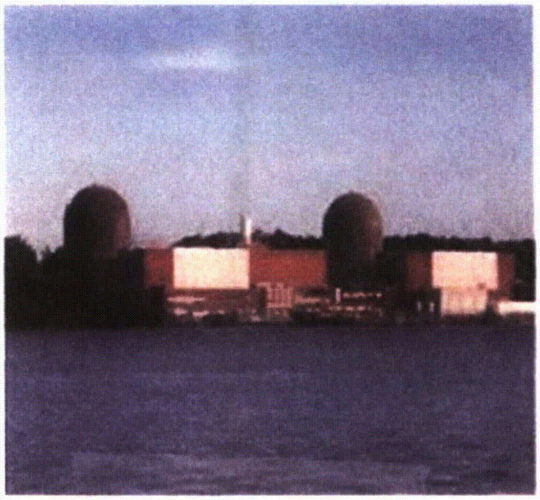
INDIAN POINT UNIT 2 AND UNIT 3



Coastal Zone Management Act Consistency Certification

In support of
Renewal of Indian Point Unit 2 and Unit 3 USNRC Operating Licenses

Submitted by:

Entergy Nuclear Indian Point 2, LLC
Entergy Nuclear Indian Point 3, LLC
Entergy Nuclear Operations, Inc.

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**SUPPLEMENTAL INFORMATION
REGARDING NYSDEC RECORD**

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STATE OF NEW YORK
DEPARTMENT OF ENVIRONMENTAL CONSERVATION

In the Matter of Entergy Nuclear Indian Point 2, LLC and Entergy Nuclear Indian Point 3, LLC For a State Pollution Discharge Elimination System Permit Renewal and Modification	DEC No.: 3-5522-00011/00004 SPDES No.: NY-0004472
In the Matter of Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations Inc.'s Joint Application for CWA § 401 Water Quality Certification	DEC App. Nos. 3-5522-00011/00030 (IP2) 3-5522-00105/00031 (IP3)

**PREFILED TESTIMONY OF DAVID HARRISON, JR., PH.D.
IN SUPPORT OF ENTERGY NUCLEAR INDIAN POINT 2, LLC, ENTERGY
NUCLEAR INDIAN POINT 3, LLC, AND ENTERGY NUCLEAR OPERATIONS, INC.**

CLOSED CYCLE COOLING AND STATE ENVIRONMENTAL QUALITY REVIEW ACT

ENTERGY NUCLEAR INDIAN POINT 2, LLC, ENTERGY NUCLEAR INDIAN POINT 3, LLC, AND ENTERGY NUCLEAR OPERATIONS, INC.

By its attorneys,

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February 28, 2014

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I. INTRODUCTION

Q. Please state your name, current position, and business address.

A. My name is David Harrison, Jr. I am an economist and Senior Vice President at NERA Economic Consulting ("NERA"), an international firm of economists specializing in microeconomics, and am co-head of NERA's global environmental practice. My business address is 200 Clarendon Street, Boston, Massachusetts 02116.

Q. Are you the same David Harrison, Jr. who submitted prefiled testimony in July 2013 as an expert witness for Entergy Nuclear Indian Point 2, LLC, and Entergy Nuclear Indian Point 3, LLC (collectively, "Entergy") in support of their application for SPDES Permit Renewal (DEC No.: 3-5522-00011/00004, SPDES No.: NY-0004472) and a Water Quality Certification (DEC App. Nos. 3-5522-00011/00030 (IP2) and 3-5522-00105/00031 (IP3)) for Indian Point Units 2 and 3 (together, the "proceeding")?

A. Yes, I am.

Q. Have you conducted any additional analysis that is relevant to the opinions and conclusions expressed in your prior July 2013 testimony?

A. Yes, I have.

Q. In broad terms, what additional analyses have you performed?

A. My additional analyses are detailed in three reports that I prepared for this proceeding in December 2013.

First, I have updated my earlier report, *Benefits and Costs of Cylindrical Wedgewire Screens at Indian Point Energy Center* (March 2013) (the "March 2013 Benefit-Cost Report"), in a new report entitled, *Benefits and Costs of Cylindrical Wedgewire Screens and Cooling Towers at IPEC* (December 2013) (Entergy Ex. 296D) (the "December 2013 Benefit-Cost Report"). As I mentioned in my prior prefiled testimony, the unavailability of certain data from other parties in this proceeding regarding their proposed alternative technologies for reducing impingement and entrainment mortality at Indian Point Energy Center ("IPEC") prevented me from completing a benefit-cost analysis regarding the use of cylindrical wedgewire screens ("CWWS") at IPEC as a means of reducing impingement and entrainment mortality, and so my earlier testimony indicated that I would be supplementing my analysis to evaluate the other parties' proposals, and to compare them economically to CWWS, once those data were available. Having received cooling tower design proposals from New York State Department of Environmental Conservation ("NYSDEC") Staff and from Riverkeeper (though I understand that Riverkeeper has since withdrawn its proposal), my December 2013 Benefit-Cost Report supplemented and completed my earlier benefit-cost analysis, including with respect to the following issues:

- construction, operation and maintenance costs for CWWS;
- construction, operation and maintenance costs for cooling towers;
- theoretical benefits of employing cooling towers; and
- the potential impacts of uncertainties on the results of benefit-cost analysis for CWWS and for cooling towers, using both sensitivity and Monte Carlo uncertainty analyses.

Second, I prepared and submitted a report that addresses the fourth step of the "best technology available" ("BTA") analysis prescribed under New York law, as applied both to CWWS and the cooling tower technologies that had been proposed in this proceeding as BTA: whether the costs of employing the technology are "wholly disproportionate" to the theoretical environmental benefits that the proposed BTA technology is hoped to yield. My analysis and findings on these issues are detailed in my report entitled, *"Wholly Disproportionate" Assessments of Cylindrical Wedgewire Screens and Cooling Towers at IPEC* (December 2013) (Entergy Ex. 297) (the "Wholly Disproportionate Report").

Finally, I have prepared a report entitled, *Impacts to the New York State Electricity System if Indian Point Energy Center Were Not Available* (December 2013) (Entergy Ex. 296E) (the "Impacts Report"), which analyzes the implications for the New York state electrical system if IPEC were to undergo an extended outage or even shut down.

II. UPDATED BENEFIT-COST ANALYSIS AND RESULTS

Q. Beginning with your December 2013 Benefit-Cost Report, you mentioned that this report supplements your earlier March 2013 Benefit-Cost Report to include additional discussion concerning construction, operation and maintenance costs for CWWS. What specific cost components have you analyzed?

A. Specifically, I have updated my earlier analysis with respect to the social cost of CWWS to include discussion of three different categories of social costs, which are referred to in the December 2013 Benefit-Cost Report as "compliance costs." First, I analyzed "capital costs," which are defined as one-time costs associated with acquiring, constructing, and installing the equipment needed to implement the proposed BTA technology, in this instance CWWS. Second, I analyze operation and maintenance costs or "O&M costs," which are defined as recurring costs associated with the operation and maintenance of the equipment, excluding costs related to ongoing power losses. Third and finally, I analyzed "electricity costs," which represent the costs to society related to changes in net electricity generation at IPEC. These include, for example, materials (*e.g.*, fuels) and other costs incurred to supply energy, capacity and ancillary services needed to replace any change in electricity output at IPEC. Other possible "external" costs associated with changes in generation, such as the costs associated with certain air emissions, also may be included within "electricity costs."

Q. Please describe how you determined what the construction and O&M costs would be for CWWS.

A. To estimate capital and O&M costs for CWWS, I relied on information provided by ENERCON. Though ENERCON was unable to supply complete O&M cost information for CWWS, those unquantified costs—for the most part resulting from the need for occasional defouling of the equipment—likely would be insignificant relative to quantified costs and therefore I concluded that the omissions would not significantly affect cost-benefit comparisons. I also determined that annual O&M cost savings were likely to result from reduced use of IPEC's current impingement and entrainment mitigation equipment. As noted in the December 2013 Benefit-Cost Report, I used current IPEC conditions as the baseline from which to measure the construction and O&M costs of CWWS. For the sake of consistency, I expressed all cost estimates in 2012 dollars, and calculated all present values as of January 1, 2013, using real (net of inflation) discount rates of 3 and 7 percent, as recommended in guidance published by the federal Office of Management and Budget ("OMB") and the Environmental Protection Agency ("EPA"). Costs were projected until September 2033 for Unit 2 and until December 2035 for Unit 3 at IPEC, corresponding to the end of each Unit's respective 20-year Nuclear Regulatory Commission ("NRC") license renewal term.

Q. Please describe how you determined what the construction and O&M costs would be for the cooling tower technologies that have been proposed as BTA in this proceeding.

A. For cooling towers, I relied on information provided by Tetra Tech in its design proposal for NYSDEC Staff, as it was more fully developed than the design proposal submitted on behalf of Riverkeeper, the only other party in this proceeding that had proposed cooling towers as BTA for IPEC—and now I understand that Riverkeeper has withdrawn its cooling towers proposal.[1] Still, the information provided by Tetra Tech was not complete, and therefore I have relied on supplemental information from other sources. In particular, I have assumed, based on information from TRC, that the operation of cooling towers would not comply with air emissions permitting requirements during some periods of the year—a factor that Tetra Tech did not assess—and I have presumed that the cooling towers would be operated at IPEC only when operation would not violate these air quality constraints. I have relied on information provided by ENERCON regarding the operations implications of air permit restrictions and air quality constraints, as that information was not provided by either Tetra Tech or by NYSDEC Staff. Based on that information, I have assumed that cooling towers would be operated only about 13 percent of the year on average (with the operating percentage varying each month in accordance with the ENERCON schedule). I have further assumed that, when cooling towers could not be operated due to air quality constraints, IPEC's current impingement and entrainment mitigation equipment would be used and would incur ongoing O&M

[1] In particular, I understand that Riverkeeper has recently withdrawn the Powers Report and, in an email from Riverkeeper counsel dated February 24 at 8:45 p.m., declined to specify what CCC proposals it actually will be advancing. My testimony is therefore limited to addressing the Tetra Tech proposal. If Riverkeeper in fact advances some other CCC proposal, then to the extent necessary I will address such proposal in rebuttal.

costs, albeit reduced to reflect the 13 percent of the time in which cooling towers would operate. As was true of the CWWS cost estimates, the cooling tower cost estimates were based upon the following methods: current IPEC conditions were used as the baseline from which to measure the construction and O&M costs of cooling towers; all cost estimates were expressed in constant 2012 dollars; all present values were calculated as of January 1, 2013, using real discount rates of 3 and 7 percent; and costs were projected until September 2033 for Unit 2 and until December 2035 for Unit 3 at IPEC.

Q. Turning to the benefits side of the analysis, please describe how you determined the theoretical benefits of the cooling tower technologies that have been proposed by DEC Staff.

A. To date, DEC Staff has not actually provided a benefits estimate for its cooling towers proposal. I therefore set about estimating the possible benefits from reducing impingement and entrainment at IPEC by the use of cooling towers. To estimate theoretical use-related benefits—*i.e.*, the theoretical benefits that would inure, directly or indirectly to those who make use of the fish resources, such as commercial or recreational fishers—from the employment of cooling towers to reduce impingement and entrainment mortality, I relied on theoretical fishery harvest estimates developed by ASA Analysis & Communication, Inc. ("ASAAC") (Entergy Ex. 300). I use the term "theoretical benefits" here because, as discussed by ASAAC separately, biological assessments indicate that reducing impingement and entrainment at IPEC would not in fact increase fish populations or harvests; ASAAC has developed theoretical calculations of fishery harvest impacts nonetheless for purposes of this analysis. To estimate the amount of theoretical benefits from cooling towers, I employed the standard economic approaches (as set forth in relevant EPA guidelines) of using market prices and non-market valuation methods to estimate the value to society of the theoretical change in fish harvests. In other words, the social benefits resulting from cooling towers are the maximum amount of money that individuals as a group voluntarily would pay to obtain the environmental improvements, *i.e.*, the theoretical increases in various fish populations. To determine those values, consistent with EPA guidance and sound economics practice, I relied on additional information including annual average *ex-vessel* commercial fish price data reported by the National Marine Fisheries Service ("NMFS") to quantify the theoretical benefits to commercial fish resource users, and also relied on a detailed, statistical meta-analysis that in turn relies on various studies of recreational fishing habits to quantify the theoretical benefits to recreational fish resource users. All theoretical benefits were discounted to present value, using real discount rates of 3 and 7 percent, consistent with EPA guidance.

Q. Was your method of determining the theoretical use benefits of cooling towers any different from the method you used to determine the theoretical use benefits of CWWS in the March 2013 Benefit-Cost Report?

A. No. To determine the theoretical use benefits of employing CWWS at IPEC, I employed the same methodology, and relied on the same basic data and analysis described above, to determine the theoretical use benefits of employing cooling towers at IPEC in the March 2013 Benefit-Cost Report.

Q. Did your analysis consider other categories of theoretical benefits, such as non-use benefits?

A. Yes. Consistent with EPA guidelines, I considered, in addition to the theoretical use-related benefits described above, the benefits that would accrue from reductions in impingement and entrainment to those who do not make use of the fish resources, *e.g.*, the benefit one may receive from knowing that a particular species of fish in the Hudson River and Atlantic Ocean continues to exist. These "non-use" benefits can be monetized only through stated preference surveys, which are both difficult and costly to perform and can often produce unreliable results. EPA guidelines recognize these difficulties and do not require that all categories of benefits be monetized or quantified, especially if it is expected that the likely cost of gathering the information necessary to do so will exceed the expected value of the additional information in the decision-making process; rather, EPA's guidance recommends a qualitative discussion of potential benefits that cannot be quantified. Here, the biological information on which I relied suggests that any non-use benefits accruing from the use of CWWS or cooling towers are unlikely to be important/significant, based on criteria from the economics literature. In light of this evaluation, and taking into account the cost and potential unreliability of conducting the stated preference survey needed to quantify or monetize them, I instead analyzed non-use benefits on a qualitative rather than a quantitative basis, consistent with EPA guidance.

Q. For purposes of the State Environmental Quality Review Act ("SEQRA"), what conclusions have you drawn with respect to the costs and benefits to be expected from CWWS and cooling tower technologies, respectively?

A. Using the cost and benefit methodologies and data described above, I calculated the present values of the social costs and theoretical social benefits for both CWWS and cooling towers. In each case, social costs exceeded theoretical social benefits by a substantial amount using either of the two discount rates employed (3 and 7 percent), meaning that the alternative that would yield the greatest positive net benefits would be leaving in place the status quo cooling water intake structure ("CWIS") configuration at IPEC, rather than installing either CWWS or cooling towers.

Q. Based on your findings, which proposed technology would impose the least costs?

A. Of the two alternatives proposed, CWWS would impose the least costs compared to IPEC's current configuration: I estimate the present value of the social costs from CWWS to be about $123.8 million (using a 7 percent discount rate) or $169.5 million (using a 3 percent discount rate), compared with $670.9 million or $1,056.6 million, respectively, for cooling towers.

Q. Based on your findings, which proposed technology would yield the most theoretical social benefits?

A. Of the two alternatives proposed, CWWS would yield the greatest theoretical benefits relative to IPEC's current configuration: I estimate the present value of the theoretical benefits from CWWS to be about $6.1 million (using a 7 percent discount rate) or $11.3 million (using a 3 percent discount rate), compared with $0.6 million or $1.2 million, respectively, for cooling towers. Cooling towers would have lower benefits than CWWS on a present value basis primarily because (1) cooling towers would only operate for about 13 percent of the year on average (as discussed above); and (2) based on engineering and permitting schedules that I used in the analyses, cooling towers would begin operation in 2026 while CWWS would be in place by 2024, and thus CWWS can reasonably be expected to provide theoretical benefits for two or more years more than cooling towers.

Q. Earlier you mentioned "uncertainty analyses"; what is an uncertainty analysis?

A. In general, uncertainty analysis is a means of evaluating the robustness of one's conclusions with respect to estimates of costs and benefits. In the context of the December 2013 Benefit-Cost Report, the benefit and cost results presented above may be thought of as "base-case" results, or "best" estimates based on sound methods applied by experts in the relevant fields using technical information, analysis of biological sampling data, reasonable assumptions, and best professional judgment. Nevertheless, some of the components of the benefit and cost estimates are inevitably subject to some degree of uncertainty. The uncertainty analysis seeks to address those uncertainties systematically and to identify their magnitudes, in accordance with well-established economic analytical practice and regulatory guidance from EPA, OMB and New York State agencies.

Q. What types of uncertainty analyses did you use?

A. I undertook both a sensitivity analysis and a "Monte Carlo" analysis of the cost and benefit estimate components.

Q. How does your sensitivity analysis work?

A. My sensitivity analysis seeks to determine which uncertainties are most critical, by examining whether plausible changes in certain variables—*e.g.*, the values of a given parameter or a certain assumption—alone and in combination with each other, could change one's overall results or conclusions.

Q. In employing your sensitivity analysis in the context of the December 2013 Benefit-Cost Report, what variables did you change?

A. I identified nine different parameters that could have significant impacts on costs and biological outcomes and that are subject to some degree of uncertainty. Two parameters could affect only cost estimates. These two parameters comprise construction costs and wholesale electricity prices. Five parameters could affect only biological outcome estimates. These five parameters comprise the biological effectiveness of CWWS; the share of fish harvested for commercial vs. recreational use for all modeled fish species; the recreational harvest value; commercial fish prices; and the extent to which commercial benefits may be reduced by incremental costs or entry into open-access fisheries resulting from higher catches. The final two parameters potentially could affect both cost and biological outcome estimates. These two parameters comprise cooling tower permitting and construction schedule, and cooling tower construction outage length.

Q. What were the results of your sensitivity analysis?

A. In every sensitivity case, costs are much higher than benefits for both CWWS and cooling towers. The lowest net costs (*i.e.*, costs minus benefits) in any sensitivity case are $103 million for CWWS and $540 million for cooling towers, based on applying a 7 percent discount rate in the "all-favorable" sensitivity case (*i.e.*, where all the sensitivity parameters were designed to lead to greater benefits and smaller costs than the initial set of parameters). The highest net costs in any sensitivity case are $197 million for CWWS and $1.494 billion for cooling towers, based upon applying a 3 percent discount rate in the "all-unfavorable" sensitivity case (*i.e.*, where all the sensitivity parameters were designed to lead to smaller benefits and greater costs than the initial set of parameters). Even combining the "all-favorable" sensitivity case for cooling towers and the "all unfavorable" sensitivity case for CWWS, the cooling towers option continues to impose many times the net costs of CWWS. These sensitivity case results lead to the conclusion that, of the two alternatives proposed as BTA, the net costs of cooling towers are always many times larger than those of CWWS under a variety of alternative assumptions.

Q. You also mentioned performing a "Monte Carlo" uncertainty analysis; what is that?

A. A Monte Carlo analysis, or Monte Carlo simulation, is a computer-assisted method of uncertainty analysis that uses statistical sampling techniques to approximate a probability distribution that generally cannot be derived analytically from point estimates of individual parameters. It builds on sensitivity analysis, generating not just a range of possible outcomes, but also a formalized mechanism for estimating the likelihoods of different outcomes.

Q. How do economists go about performing a Monte Carlo analysis?

A. Monte Carlo analysis requires explicitly defining a probability distribution of the values for each parameter that is to be included in the analysis. These probability distributions capture the ranges of possible values the inputs might take and the likelihood of the occurrences of these values: input values associated with higher probabilities will be selected more often during the simulation, while those associated with lower probabilities will be selected less often. Each iteration of the Monte Carlo simulation draws a random sample value from each of the input probability distributions, and then uses those values to calculate a value for the outcome measure or measures, here net benefits or net costs. The process is then repeated a large number of times (*e.g.*, one thousand times) to simulate the probability distribution of the result (*e.g.*, net costs): the greater the number of iterations or trials run, the more precisely the probability distribution of the outcome measure can be simulated.

Q. Is Monte Carlo analysis generally accepted and practiced by members of the economic, scientific and statistical communities?

A. Yes. Monte Carlo analysis is an important method for developing formal quantitative uncertainty assessments, and it is particularly useful because it explicitly characterizes analytical uncertainty and variability. EPA, among other regulators, has specifically approved the use of Monte Carlo analysis.

Q. What were the results of your Monte Carlo analysis?

A. Using most of the same parametric sources of uncertainty that were considered in connection with the sensitivity analysis and developing probability assumptions for the various parameters, I ran 1,000 trials or iterations of the Monte Carlo simulation described above. Comparing CWWS and cooling towers, there was not a single trial in which the net cost of cooling towers was lower than the net cost of CWWS. Further, in every single trial, cooling towers were found to have higher costs and lower benefits than CWWS.

Q. Having performed these uncertainty analyses, what are your findings?

A. The results of the uncertainty analyses also confirm my previously stated conclusions that of the two proposed BTA technologies, cooling towers have much greater costs and lower benefits than do CWWS.

III. <u>WHOLLY DISPROPORTIONATE REPORT ANALYSIS AND CONCLUSIONS</u>

Q. Let us turn to your analysis and conclusions in your Wholly Disproportionate Report. What was the purpose of that Report?

A. The purpose of the Wholly Disproportionate Report was to provide the required economic assessment of the two CWIS technologies that have been proposed as BTA for reducing impingement and entrainment mortality at IPEC: CWWS and cooling towers. I understand that, under New York law, a four-step analysis governs whether a particular CWIS technology is BTA, comprising (1) whether the facility's CWIS may result in adverse environmental impact; (2) if so, whether the location, design, construction and capacity of the CWIS reflects BTA for minimizing adverse environmental impact; (3) whether practicable alternate technologies are available to minimize the adverse environmental effects; and (4) whether the costs of practicable technologies are "wholly disproportionate" to the environmental benefits they confer. Specifically, the Wholly Disproportionate Report's analysis and conclusions pertain to the fourth step, *i.e.*, whether the costs of CWWS or of cooling towers are "wholly disproportionate" to their respective benefits.

Q. **In preparing the Wholly Disproportionate Report, did you consider the same cost and benefit information that you discussed in your December 2013 Benefit-Cost Report?**

A. Yes, with the exceptions that the theoretical benefits were not translated into monetary values and various measures of theoretical biological benefits were included.

Q. **How did you use that cost and benefit information to support the analysis reported in the Wholly Disproportionate Report?**

A. As is standard and accepted practice in the economic evaluation of competing policy alternatives and consistent with NYSDEC's explication of the "wholly disproportionate" test, I sought to compare the incremental costs and incremental benefits for each of the BTA technologies proposed with alternatives ordered in terms of their costs. Specifically, in evaluating whether costs are "wholly disproportionate" to benefits for CWWS and cooling towers, I compared (1) the costs and theoretical benefits of CWWS incremental to the current configuration of IPEC; and (2) the costs and theoretical benefits of cooling towers incremental to CWWS.

Q. What were your findings?

A. I found that, compared to IPEC's current configuration, CWWS yield costs and theoretical harvest benefits (with respect to fish populations) that would equate to a cost of about $885 or $1,199 per additional fish harvested (at 3 and 7 percent discount rates, respectively), many times the values that individuals place on commercial and recreational harvests. Compared to CWWS, I found that cooling towers would have substantially greater costs and substantially lower theoretical harvest gains. Stated another way, CWWS "dominate" cooling towers—that is, CWWS are superior to cooling towers by any benefit-cost criterion because their benefits are greater and their costs are smaller. Based on the "dominant" relationship that is evident between the proposed alternatives, I conclude that the costs of cooling towers are "wholly disproportionate" to their theoretical environmental benefits, vis-à-vis CWWS.

Q. Did you conduct any additional uncertainty analysis to confirm the findings of your Wholly Disproportionate Report, as you did with your December 2013 Benefit-Cost Report?

A. Yes, I conducted a sensitivity analysis similar to that described above in connection with the December 2013 Benefit-Cost Report.

Q. What were the results of your sensitivity analysis?

A. Using even extreme assumptions in favor of CWWS (relative to the current conditions) and of cooling towers (relative to CWWS), neither would pass the "wholly disproportionate" test under step four of New York's BTA analysis. The results of the sensitivity analysis further confirm the correctness of the conclusion that the expected additional costs of cooling towers are "wholly disproportionate" to any plausible additional environmental benefits that cooling towers would achieve in comparison to CWWS.

Q. Did those results affect your conclusion that CWWS dominate cooling towers?

A. No.

Q. Having performed this uncertainty analysis, are you confident in your conclusion that CWWS dominate cooling towers?

A. Yes.

Q. Did you consider which proposed technology provides the most benefit on an annual basis in addition to which provides the most benefit on an aggregate basis over the license renewal term?

A. Yes.

Q. What were your findings regarding annual benefits?

A. I determined that the theoretical annual benefits are similar for CWWS and cooling towers, although CWWS would yield greater theoretical benefits on an annual basis as well as on an aggregate basis. This annual result arises because, contrary to Tetra Tech's implicit assumption, and as discussed previously, I assume cooling towers cannot be operated continuously throughout the year. Instead, due to the air quality constraints, cooling towers would be available to reduce impingement and entrainment mortality at IPEC only approximately 13 percent of the year on average. As a result, during most of the year when cooling towers could not be used consistent with air quality requirements, cooling towers would yield no incremental biological benefits compared to either CWWS or the current configuration of IPEC.

Q. What were your findings with respect to aggregate benefits?

A. As noted above, based on engineering and permitting assumptions used in my analysis, CWWS would be operational starting in 2024 whereas cooling towers would be in operation starting in 2026. Together with the findings discussed above that CWWS provide greater benefits on an annual basis, CWWS leads to much greater theoretical benefits than cooling towers on an aggregate or cumulative basis.

Q. Under any circumstances you considered do cooling towers provide greater theoretical benefits than CWWS on an annual basis?

A. Only in a scenario where one assumes no restrictions on the extent to which cooling towers can be operated due to, *e.g.*, air quality considerations. Even in that situation, however, CWWS continue to have greater benefits on an aggregate basis, because the shorter construction period for CWWS (based on engineering and permitting assumptions) results in two extra years of benefits.

Q. Is it reasonable to base an economic analysis on the benefits expected in a single year as opposed to the benefits expected in the aggregate?

A. No. When benefits are spread out over a long time, *e.g.*, the 20-year NRC license extension term, decision-makers considering whether the incremental benefits of a proposed alternative exceed its incremental costs should consider benefits in the aggregate, not just in a single year. That is the proper methodology for a sound economic analysis. Indeed, I understand that Mr. Nieder noted this principle during his testimony at the previous set of hearings before the Tribunal, stating that "you're supposed to take as thorough of a look at it as you can to understand all the impacts and all the benefits over the life of the project." July 17, 2013 Tr. at 6403:23-6405:15.

Q. In your Wholly Disproportionate Report, did you make any assumptions regarding future wholesale electricity prices?

A. Yes.

Q. Why is the future wholesale price of electricity relevant to your economic analysis of costs, benefits and wholly disproportionate results?

A. Future wholesale electricity prices are relevant to benefit-cost analysis, and therefore to BTA analysis, because both CWWS and cooling towers would lead to changes in IPEC's electricity generation, with CWWS increasing output and cooling towers decreasing output relative to the current conditions at the plant. Cooling towers lead to decreased generation because of both construction outages and ongoing increases in parasitic and efficiency losses. Future wholesale electricity prices represent the price that would have to be paid to secure replacement power to make up for IPEC's reduced output, and thus provide a measure of the social cost of replacement power. These costs are relevant to an assessment of the social cost of the two proposed BTA technologies.

Q. Please describe how you arrived at the assumptions you used for future wholesale electricity prices in your two reports.

A. I developed forecasts of monthly wholesale electricity prices over the relevant time period for a region consisting of New York City and Westchester County, New York, based on annual wholesale electricity price projections from the U.S. Energy Information Administration ("EIA") and historical data on wholesale electricity prices from the New York Independent System Operator ("NYISO").

Q. Did you rely on any projections by Entergy of what future wholesale electricity prices may be?

A. No.

Q. Why not?

A. It is my understanding that Entergy's projections of future wholesale electricity prices are sensitive, confidential business information that the company protects as a trade secret, and to which it strictly limits access. There was ample information that was publicly available from EIA and NYISO, and thus it was not necessary to use Entergy's internal price forecasts.

IV. IMPACTS REPORT ANALYSIS AND CONCLUSIONS

Q. Let us turn finally to your Impacts Report. Why did you prepare and submit this report?

A. The purpose of the Impacts Report was to analyze under SEQRA the impacts to the New York State electricity system that result from disruption of IPEC's operations, in connection with evaluating the proposal from NYSDEC Staff that IPEC be required to employ closed-cycle cooling towers. I understand that under SEQRA, specifically Section 617.7(c)(1)(vi), consideration of the potential environmental, social and economic impacts of proposed actions is required, including whether the proposed action would lead to "a major change in the use of either the quantity or type of energy." To that end, the Impacts Report assesses the potential electricity reliability and price impacts of requiring IPEC to install and make use of cooling towers to reduce impingement and entrainment mortality at IPEC, which may lead to IPEC being unavailable to supply electricity some or all of the time.

Q. How did you go about preparing the analysis that underlies the Impacts Report?

A. I analyzed the impacts to the electricity system and other related impacts if IPEC were not available to supply electricity, along various relevant dimensions—*i.e.*, reliability, capacity, wholesale electricity prices, consumer electricity prices, greenhouse gas emissions, local air emissions, and fuel diversity—using a state-of-the-art electricity market model (PROMOD IV) that is widely used by utilities, regulators, power suppliers, and other electricity market participants. The PROMOD model simulates the operation of regional electricity markets on an hourly basis to project market-clearing prices and production operating costs. Use of the model requires the development of projected values for key market inputs, including (as relevant here) generation capacity, electricity demand, transmission constraints, fuel prices, and other factors.

Q. What were your findings?

A. My conclusions are that IPEC is a major component of the New York State electricity system, and so any unavailability to supply electricity would result in substantial adverse near-term impacts on various aspects of the electricity system, including system reliability, system capacity, wholesale and consumer electricity prices, New York State electricity expenditures, greenhouse gas and local air emissions (as natural gas and other fossil fuel-burning sources provided replacement power) and fuel diversity. For example, New York State consumers would pay increased annual expenditures for electricity that range from about $1.6 billion to about $2.0 billion per year.

END OF TESTIMONY

Appendix E

Impacts to the New York State Electricity System if Indian Point Energy Center Were Not Available
(NERA)

Appendix E

December 2013

Impacts to the New York State Electricity System if Indian Point Energy Center Were Not Available

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Executive Summary

This report analyzes the benefits to the New York State electricity system from Indian Point Energy Center (IPEC) in the context of a review under the State Environmental Quality Review Act (SEQRA) of proposals by the New York State Department of Environmental Conservation (NYSDEC) and Riverkeeper to require closed-cycle cooling towers at IPEC. SEQRA requires that proponents evaluate the potential environmental, social and economic impacts of proposed actions, including whether the proposed action would lead to "a major change in the use of either the quantity or type of energy" (Section 617.7(c)(1)(vi)). This report assesses potential reliability and price impacts if a requirement to install cooling towers made IPEC unavailable to contribute to the electricity system, including the possibility of an extended outage due to blasting or other conditions. Neither NYSDEC nor Riverkeeper has considered these potential energy impacts of their proposal.

We evaluate the energy system impacts if IPEC were not available in terms of the following effects:

1. New York State reliability impacts;
2. New York State electricity capacity prices;
3. New York State wholesale electric energy prices;
4. New York State consumer electricity expenditures;
5. Greenhouse gas emissions in relation to New York State climate change goals;
6. Local air emissions in relation to New York State air quality goals; and
7. New York State fuel diversity in relation to New York State concerns.

Our analysis of capacity price impacts is based on the capacity market framework in New York State. Our empirical results for the wholesale energy price and related system impacts are based on a state-of-the-art electricity market model, PROMOD IV—which has been extensively used in analysis of electricity markets in New York State and throughout North America—and on up-to-date projections of model inputs. To provide an indication of the nature of the potential near-term effects of IPEC not being available, we model the five-year period from 2015 to 2019.

A. New York State Reliability Impacts

All else equal, loss of IPEC from the New York State electricity system would have significant adverse impacts on reliability in New York State. Electricity system reliability refers to the ability of the system to provide power under projected demand conditions and typically is measured in terms of loss-of-load expectation (LOLE), which is the expected number of days in a given year in which lack of sufficient electricity capacity would cause customer load to be involuntarily cut off. The maximum LOLE level allowed by New York State electricity system regulators is 0.1—i.e., a situation in which an involuntary load cutoff would be expected to occur on one day per ten years when electricity capacity was not sufficient to meet demand.

The National Research Council (NRC) and the New York Independent System Operator (NYISO) have evaluated the potential effects on electricity system reliability if IPEC were not available. The NRC—an independent group of experts organized by the National Academy of Sciences—performed detailed analyses of various potential scenarios. In one scenario, the NRC assumed baseline growth in capacity around the time of IPEC retirement but no new capacity added specifically to address the retirement. In this scenario, the NRC concluded that LOLE in New York State would increase to over 13 times the allowable level (NRC 2006, p. 62). The NRC also developed scenarios with significant capacity additions and demand reductions to address IPEC retirement, but it noted that "[a]ll these measures will take time to implement, and several factors may converge to make it even more difficult" (NRC 2006, p. 73).

Recent studies by NYISO also conclude that IPEC retirement would pose serious reliability challenges for New York State. In its *2012 Reliability Needs Assessment (RNA)*, the most recent version, NYISO concluded that LOLE in New York State would rise to almost five times the allowable level in 2016 assuming baseline conditions for other capacity, demand, and transmission (NYISO 2012, p. 43). NYISO reiterated the reliability risks of IPEC retirement in the *2013 Power Trends* report (NYISO 2013b, p. 43) and testimony to the New York State Senate Energy and Telecommunications Committee in September 2013 (NYISO 2013c).

The prior studies indicate that substantial amounts of additional generation capacity and perhaps also transmission capacity would be necessary to prevent violations of New York State's reliability standard if IPEC were not available to the electricity system. The New York State Public Service Commission's (PSC) Reliability Contingency Plan (RCP) proceeding was initiated to develop a contingency plan concerning IPEC-related system needs. In November 2013, the PSC adopted a series of "no regrets" transmission measures and an incremental energy efficiency program as part of the contingency plan, which it described as providing system benefits irrespective of IPEC's future operating status.

The price and consumer expenditures impacts presented in this report assume that the transmission and energy efficiency increases approved in the RCP proceeding are implemented for the purposes of this analysis, although they were approved without regard to the status of IPEC. We also presume that various additional adjustments are made—including reactivation of some mothballed units—to meet the reliability requirements if IPEC were not available. These adjustments are consistently applied in the modeling of capacity price and electric energy price impacts.

B. New York State Electricity Capacity Price Impacts

New York State capacity prices would increase substantially if IPEC were not available, leading to increased electricity capacity payments by load-serving entities (LSEs). Capacity markets are designed to provide financial incentives to electricity generators in order to provide sufficient capacity to meet electricity demand in all periods. The increase in capacity prices reflects the increased value of capacity on the system and is required to induce market-based solutions that would mitigate the reliability impacts if IPEC were not available. Capacity prices in these markets are measured in dollars per kilowatt of installed capacity per month (kW-month).

Table S-1 shows our estimates of increases in capacity prices during summer months in the New York Control Area (NYCA)—which represents the entire state—if IPEC were not available.[1] NYCA prices are estimated to increase by between \$2.34/kW-month and \$3.23/kW-month. The increases represent between 32 percent and 72 percent of baseline projected capacity prices.

Table S-1. Increases in New York Control Area Summer Capacity Prices if IPEC Were Not Available (nominal \$/kW-month)

		IPEC Not Available		
	Base	Price	Increase	% Increase
2015	\$4.42	\$7.61	\$3.20	72%
2016	\$5.51	\$8.74	\$3.23	59%
2017	\$6.24	\$9.27	\$3.02	48%
2018	\$6.31	\$8.88	\$2.57	41%
2019	\$7.19	\$9.53	\$2.34	32%

Source: NERA calculations as explained in text

C. New York State Wholesale Electric Energy Price Impacts

Table S-2 summarizes our estimates of the average annual increases in New York State wholesale electric energy prices from 2015 to 2019 if IPEC were not available. The increases range from \$2.27 to \$2.57 per megawatt-hour (MWh). Baseline statewide average annual wholesale electric energy prices are projected to be about \$39/MWh during this period; thus, the overall New York State impacts represent an increase of about 6 percent from baseline prices. Electricity price increases in the densely populated Southeastern New York region would be substantially greater than the statewide average, as shown in the report body.

1 Capacity prices are reported in nominal dollars to facilitate exposition of the underlying calculations. Electric energy prices and consumer expenditures are reported in constant 2012 dollars. We converted nominal dollars to constant 2012 dollars using projected GDP price deflators in OMB (2013, p. 6).

Table S-2. Increases in New York State Wholesale Energy Prices if IPEC Were Not Available (2012$/MWh)

		IPEC Not Available		
	Base	Price	Change	% Change
2015	$37.88	$40.26	$2.39	6.3%
2016	$38.34	$40.91	$2.57	6.7%
2017	$39.05	$41.37	$2.32	5.9%
2018	$39.09	$41.36	$2.27	5.8%
2019	$39.90	$42.29	$2.39	6.0%

Source: NERA calculations as explained in text

D. New York State Consumer Expenditure Impacts

New York State residents currently face among the highest retail electricity prices in the nation. Retail electricity prices include components based on wholesale electricity and capacity prices (as well as other components). Not having IPEC available would lead to substantial increases in retail prices and commensurate increases in power expenditures for New York State consumers.

Figure S-1 shows estimates of the increases for New York State consumer expenditures over our modeling period if IPEC were not available. These values include the effects of both increased capacity prices and increased wholesale electricity prices. New York State consumers would pay increased annual expenditures for electricity that range from about $1.6 billion to about $2.0 billion per year. The total projected increase in New York State consumer payments for electricity from 2015 to 2019 is projected to be almost $9 billion if IPEC were not available. The impacts do not, however, include any costs for constructing or reactivating facilities to meet reliability requirements that would be required in addition to market prices.

Figure S-1. Increases in New York State Consumer Electricity Expenditures if IPEC Were Not Available (millions of 2012$)

Source: NERA calculations as explained in text

E. Regional Greenhouse Gas Emission Impacts

IPEC produces virtually no carbon dioxide (CO_2) emissions, but empirical modeling indicates that much of the power to replace IPEC generation would come from fossil-fired power plants that produce CO_2 emissions. If IPEC were not available, replacement generation would lead to substantial initial increases in CO_2 emissions, increasing the cost of achieving climate change goals as embodied in the Regional Greenhouse Gas Initiative (RGGI). RGGI is an agreement among nine Northeastern states to provide an overall regional cap on CO_2 emissions based upon target reductions set by the individual states.

Table S-3 shows estimated initial increases in CO_2 emissions across the RGGI region if IPEC were not available. We report results for the RGGI region rather than just New York State because the climate change effects of CO_2 emissions do not depend on the location of the emissions and because generators from outside New York State would produce different levels of electricity if IPEC were unavailable. The average annual initial CO_2 emissions increase if IPEC were not available would be about 6.7 million tons.[2] The table also shows New York State's CO_2 reduction goals for the RGGI program in each year relative to the state's target

[2] RGGI sets an overall cap on emissions, so increases resulting from replacement generation would have to be offset by reductions in emissions from other covered sources. Nonetheless, the initial or gross increases in emissions provide a useful sense of the extent to which replacing the lost output associated with cooling towers at IPEC would make achievement of the caps more difficult and/or more costly.

emission level for 2014. In each year of the modeling period, the estimated increase in CO_2 emissions in the RGGI region is many times larger than New York State's target CO_2 reduction.

Table S-3. Initial Increases in Regional CO_2 Emissions if IPEC Were Not Available (million tons)

		IPEC Not Available			Change As % of NYS RGGI Goals	
	Base	Emissions	Change	% Change	Annual Goal	Change / Goal
2015	115.7	122.3	6.6	5.7%	0.9	747%
2016	117.9	124.6	6.6	5.6%	1.7	381%
2017	120.5	126.8	6.2	5.2%	2.4	260%
2018	119.9	127.0	7.1	5.9%	3.2	221%
2019	120.0	126.9	6.9	5.8%	4.0	172%

Note: NYS RGGI reduction goals are relative to the state's emissions cap in 2014.
Source: NERA calculations as explained in text

F. New York State NO_x Emission Impacts

Replacement generation if IPEC were not available also would lead to significant initial increases in nitrogen oxides (NO_x) emissions, which are important for air quality requirements related to ozone concentrations. Table S-4 shows increases in NO_x emissions if IPEC generation were not available. On average, loss of IPEC from the electricity system would increase annual NO_x emissions by about 3,000 tons. As part of its state implementation plan (SIP) for the New York Metropolitan Area particulate matter ($PM_{2.5}$) non-attainment area, New York aims to reduce NO_x emissions from relevant point sources, including power plants, by 1,100 tons between 2007 and 2017. The table shows that the annual increases in New York State NO_x emissions if IPEC generation were not available are about three times the NO_x reduction goal for New York State's SIP.

Table S-4. Increases in New York State NO_x Emissions if IPEC Were Not Available (tons)

		IPEC Not Available			Change As % of NYS SIP Goal	
	Base	Emissions	Change	% Change	'07-'17 Goal	Change / Goal
2015	17,723	20,841	3,119	18%	1,100	284%
2016	17,574	20,867	3,292	19%	1,100	299%
2017	18,203	21,562	3,359	18%	1,100	305%
2018	17,792	20,373	2,582	15%	1,100	235%
2019	17,815	20,319	2,504	14%	1,100	228%

Note: NO_x SIP goal is reduction of 1,100 tons from point sources (including power plants) from 2007 to 2017.
Source: NERA calculations as explained in text

G. Fuel Diversity Impacts

Regulators in New York State have raised concerns for many years about the state's reliance on natural gas-fired generation, especially in downstate areas, and about the adverse implications for fuel diversity if IPEC were not available. A 2008 NYISO white paper on fuel diversity stated that "comparatively limited downstate fuel diversity poses certain risks for the New York City and Long Island areas" (NYISO 2008, p. 3-6) and that "closure [of IPEC] could exacerbate New York City's existing dependence on natural gas for power production" (NYISO 2008, p. 3-6). NYISO's *2013 Power Trends* report notes that the state's reliance on natural gas-fired generation has more than doubled in recent years, from 27 million MWh in 2004 to almost 60 million MWh in 2012 (NYISO 2013b, p. 35). The report also notes that increased reliance on natural gas for power generation means that any disruption in natural gas supply could have significant implications for system reliability, and volatility in natural gas prices could cause large swings in power prices for New York State power consumers (NYISO 2013b, pp. 35-36).

Table S-5 shows the additional natural gas that would be consumed by power plants in New York State if IPEC were not available. Annual natural gas usage for electricity would increase by about 94 million MMBtu if IPEC were not available, an increase of more than 18 percent over base case levels. This increase is roughly equivalent to the annual natural gas usage of 1.4 million New York State households, based on average annual natural gas consumption of 69 MMBtu per household for all fuel uses (EIA 2013b).

Table S-5. Increases in New York State Electricity Sector Natural Gas Consumption if IPEC Were Not Available (million MMBtu)

		IPEC Not Available		
	Base	Consumption	Change	% Change
2015	497	593	95	19%
2016	510	601	91	18%
2017	513	611	97	19%
2018	518	611	93	18%
2019	512	608	95	19%

Source: NERA calculations as explained in text

I. Introduction and Overview

This report analyzes the effects on the New York electricity system if Indian Point Energy Center (IPEC) were not available in the context of a review under the State Environmental Quality Review Act (SEQRA) of proposals to require closed-cycle cooling towers (Cooling Towers) at IPEC. The report assesses various potential near-term impacts if a requirement to install Cooling Towers made IPEC unavailable to contribute power to the electricity system for some reason, such as an extended outage. First, we consider the potential impacts of IPEC not being available on New York State electricity system reliability. Second, we analyze effects on capacity and wholesale electricity prices if IPEC were not available. Third, we consider the implications of these price changes on total electricity expenditures by New York State consumers. Finally, we consider the implications of IPEC not being available for New York State goals related to three energy and environmental issues: climate change, local air quality, and fuel diversity.

This chapter provides background information and an overview of the structure of the remainder of the report.

A. Background on Indian Point Energy Center

IPEC is located in the Village of Buchanan in upper Westchester County, New York. The generating plant consists of two pressurized light water reactors, Unit 2 and Unit 3,[3] owned by Entergy Nuclear Indian Point 2, LLC and Entergy Nuclear Indian Point 3, LLC. The combined summer net capacity of the two units is approximately 2,070 megawatts (MW) (NYISO 2013a, p. 30).

1. Role within New York State Electricity System

As a nuclear generating station, IPEC generally has lower marginal costs than fossil-fired generating units and different operating characteristics. Thus, it provides base-load generation service to the New York Independent System Operator (NYISO), the entity responsible for operating the electric transmission system and New York's competitive wholesale electricity markets. IPEC generally operates at full capacity except during scheduled outages for refueling and maintenance (typically, fewer than 30 days per year).

IPEC is situated in NYISO's Zone H (Millwood), in the southeastern New York region. In 2012, IPEC generated 16.9 million megawatt-hours (MWh) of energy, more than twice as much power as any other single facility in southeastern New York (NYISO 2013a, p. 30).[4] IPEC also provides voltage services necessary to maintain transmission capabilities both locally and on certain major interfaces (NYISO 2005, 2012). Moreover, IPEC contributes to the ability of New York to meet key climate change and air quality targets, including carbon dioxide (CO_2) targets related to the

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[3] Unit 1 at IPEC ceased operation in 1974.

[4] We define southeastern New York to comprise NYISO Zones G through K (see map below).

Regional Greenhouse Gas Initiative (RGGI) as well as nitrogen oxides (NO_x), sulfur dioxide (SO_2), and mercury targets related to conventional and toxic air quality goals.

2. Key Characteristics of IPEC

IPEC has five major characteristics that make it critical to meeting New York State needs related to capacity, energy, climate change, and air quality.

1. *Location.* IPEC is located in southeastern New York State, which represents the majority of the state's electricity demand and has been supply-constrained because of the difficulty and cost of siting new generation and transmission infrastructure there.

2. *Capacity.* IPEC represents more than 10 percent of the total generating capability in southeastern New York (NYISO 2013a, pp. 30, 48).

3. *Baseload operation and generation.* Except during outages, IPEC produces power all months of the year and hours of the day. As a result of its large size and high utilization, IPEC generated more energy in 2012 than any other facility in southeastern New York. Indeed, IPEC's power amounted to approximately 18 percent of the energy consumed in southeastern New York in that year (NYISO 2013a, pp. 30, 16).

4. *Voltage service.* In addition to the energy and capacity it provides, IPEC is a critical source of voltage support in the Lower Hudson Valley and is thus essential to the local transmission system (NYISO 2005, 2012). This contribution to transmission capacity is particularly important because of the difficulty of siting additional generation and transmission capacity in or around New York City.

5. *Non-emitting.* IPEC produces virtually no CO_2, NO_x, SO_2, mercury, or other air emissions. Thus, IPEC contributes substantially to the ability of New York State to meet key climate change and air quality goals.

These characteristics mean that loss of IPEC would have substantial negative effects on electricity system, climate change, and air quality objectives in New York State.

B. Background on Cooling Tower Proposals and SEQRA Review

The New York State Department of Environmental Conservation (NYSDEC) Staff and Riverkeeper have proposed that Cooling Towers be considered Best Technology Available (BTA) and thus required for IPEC to obtain a state cooling water permit under Section 316(b) of the federal Clean Water Act. SEQRA requires that proponents consider the potential environmental, social and economic impacts of proposed actions. In particular, Section 617.7(c)(1)(vi) states that environmental impact statements should include discussion of "a major change in the use of either the quantity or type of energy." Moreover, section 617.9(b)(5)(iii)(e) states that environmental impact statements should include "impacts of the proposed action on the use and conservation of energy (for an electric generating facility, the statement must include a demonstration that the facility will satisfy electric generating capacity needs or other electric systems needs in a manner reasonably consistent with the most recent state energy plan)."

NYSDEC has sponsored a report by Tetra Tech that considers the costs of their proposed Cooling Tower design, including electricity costs due to construction and operation of their towers (Tetra Tech 2013). In addition, Riverkeeper has sponsored a report by Powers Engineering (Powers 2013). But neither NYSDEC nor Riverkeeper has provided an analysis of the potential electricity system impacts if a requirement to install Cooling Towers made IPEC unavailable to contribute to the electricity system for an extended period.

C. Study Objectives

The objective of this study is to assess the electricity system and related impacts if IPEC were not available. Thus, the study provides information on the potential energy-related impacts under SEQRA of a requirement to install cooling towers. We consider impacts along the following dimensions:

1. New York State reliability impacts;
2. New York State electricity capacity prices;
3. New York State wholesale electric energy prices;
4. New York State consumer electricity expenditures;
5. Greenhouse gas emissions in relation to New York State climate change goals;
6. Local air emissions in relation to New York State air quality goals; and
7. New York State fuel diversity in relation to New York State concerns.

Together these various impacts provide an indication of the potential impacts to the electricity and energy system from IPEC operation and the potential changes that could occur if IPEC were not available. The timeframe we consider is from 2015 to 2019.

D. Background on PROMOD Model

We use PROMOD IV to estimate the effects on electric energy prices and related environmental and fuel effects if IPEC were not available. PROMOD IV is a state-of-the-art electricity market model that is widely used by utilities, power marketers, traders, and other market participants. PROMOD simulates the operation of regional electricity markets on an hourly basis to project market clearing prices and production operating costs. PROMOD is recognized for its flexibility and breadth of technical capability, incorporating extensive details in transmission constraints, generation analysis, and unit commitment/operating conditions. Information on the PROMOD model is provided in Appendix C.

Modeling the electricity system with PROMOD requires the development of projected values for key market inputs. We develop detailed PROMOD modeling inputs for generation capacity, electricity demand, transmission, fuel prices, and other factors. Fuel price estimates are based on information from forward markets. Forecasts of demand are obtained from the relevant ISOs and RTOs. Detailed information on our PROMOD modeling inputs is provided in Appendix D.

E. Organization of This Report

The remainder of this report is organized as follows. Chapter II provides an overview of the New York State electricity system, including conceptual frameworks for evaluating the impacts of IPEC unavailability on reliability, capacity prices, and wholesale energy prices. Chapter III provides information on electricity system reliability effects. Chapter IV provides the results of our analyses of the impacts of IPEC unavailability on near-term capacity and wholesale electricity prices. Chapter V provides the implications of the electricity price increases for New York State consumer electricity expenditures. Chapter VI provides results for environmental and fuel diversity goals. Chapter VII provides conclusions.

Appendix A describes modeling assumptions based on reliability requirements. Appendix B describes the methodology for modeling capacity price impacts. Appendix C provides an overview of PROMOD. Appendix D describes the PROMOD modeling inputs.

II. New York State Electricity System

This chapter provides an overview of the New York State electricity system, including conceptual frameworks for evaluating impacts on reliability, capacity prices, and wholesale energy prices if IPEC were not available.

A. New York Electricity System Reliability

Providing adequate electricity to meet demand at essentially all times is a reliability requirement for the New York State electricity system. This section provides background on New York State reliability requirements and how reliability would be affected if IPEC were not available.

1. Background on New York State Electricity System Reliability

The New York State Reliability Council (NYSRC) is charged with determining the minimum level of installed capacity supply in New York State that must be available to meet electricity demand. In advance of each summer peak period, NYSRC (in coordination with NYISO) establishes statewide reserve margin requirements for that summer. NYISO establishes the locational requirements within the State. The reserve margin is the ratio of available capacity to expected peak demand during a given summer period. For example, if a hypothetical electricity system had an expected peak demand of 1,000 MW and 1,100 MW of available capacity, then the reserve margin would be 100 MW relative to 1000 MW, or 10 percent.

The standard that NYSRC uses to establish the reserve requirement is known as loss-of-load expectation (LOLE), a metric that measures the expected number of days per year during which lack of sufficient available capacity would require involuntarily disconnecting some customers' loads from the grid. The North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and NYSRC mandate a maximum LOLE of 0.1 in New York State—that is, they require an expected frequency of involuntary load disconnection of no more than one day per ten years (NYISO 2012).

To mitigate the risk of involuntarily disconnecting customer load, NYISO maintains emergency operating procedures to help preserve reliability in the event of a capacity shortage. Table 1 lists the measures that NYISO may take in the event of threats to electric reliability. The measures are listed in the order in which they are likely to be utilized (as specified by NYSRC). All of these measures are costly, and are generally used only when conventional resources are insufficient. Table 1 briefly summarizes the potential adverse impact of each measure. For example, special case resources (SCRs) are resources that are compensated to discontinue or reduce industrial/commercial loads during peak demand times. These reductions can lead to decreased productivity and/or decreased efficiency at the companies. Voltage reductions can increase the risk of damage to electric equipment. Emergency purchases are often highly costly to the wholesale power system. Involuntary customer disconnections can have wide-ranging negative impacts, including on public safety (e.g., traffic lights).

Table 1. NYISO Emergency Operating Procedures

Measure	Potential Adverse Effect
Special Case Resources (SCRs)	Economic impact
Emergency demand response programs	Economic impact
5% manual voltage reduction	Risk to equipment
30 minute reserve to zero	Risk to electricity system security
5% remote voltage reduction	Risk to equipment
Voluntary industrial curtailment	Economic impact
General public appeals	Economic impact
Emergency purchases	Economic impact
10 minute reserve to zero	Risk to electricity system security
Customer disconnections	Economic and public safety effects

Source: NYSRC (2012, p. 83)

2. Potential Impacts on Electricity System Reliability if IPEC Were Not Available

Loss of IPEC would impair electricity system reliability and would increase the likelihood that the measures listed in Table 1 would need to be taken. IPEC plays an important role in maintaining electricity system reliability in southeastern New York State for two main reasons. First, IPEC represents a large amount of capacity (about 2,070 MW) in a supply-constrained part of the State. Thus, removing IPEC from the electricity system would significantly reduce the cushion of excess capacity relative to demand (which is often a few thousand megawatts or less). Second, IPEC provides voltage support for southeastern New York State, which helps maintain the transmission system. For example, NYISO issued a study in 2005 indicating that removal of IPEC would reduce transmission capabilities for the Sprain Brook-Dunwoodie South and UPNY-Con Edison transmission interfaces (NYISO 2005).

The New York State Public Service Commission (PSC) has initiated a proceeding called the Reliability Contingency Plan (RCP) to develop a contingency plant concerning IPEC-related system were IPEC to become unavailable even though IPEC's owners are actively pursuing a 20-year license renewal (PSC 2013a). The RCP is discussed in detail in Chapter III.

B. Overview of New York State Capacity Markets

As noted above, NYISO administers capacity markets to encourage investment in generation capacity in order to provide New York electricity system reliability. This section provides background on New York State capacity markets and how capacity prices would be affected if IPEC were not available.

1. Background on New York State Capacity Markets

In a capacity market auction process, capacity providers (power plants) make their generation capacity available to load-serving entities (that is, they "bid into" the capacity market), and in return receive payments from LSEs. In effect, LSEs pay the power plants for the assurance that the power plants would provide power if called upon. The presence of capacity markets thus provides the "missing money" to incentivize investment in generation capacity—beyond the payments for electric energy—so that there will be capacity sufficient to meet load even in times of peak electricity demand.

To set capacity prices, NYISO starts with a defined "reserve margin" by which generation capacity should exceed projected peak demand (or "load"). NYISO sets the installed capacity (ICAP) requirement for each capacity market by increasing the peak demand by the reserve margin. Capacity prices are then determined based on the amount of excess capacity relative to the ICAP requirement that clears the auction. As described in more detail below, NYISO uses an administrative demand curve (based on parameters described below and in more detail in Chapter IV) to set capacity prices.

NYISO divides the New York electricity system into various capacity markets, each of which has separate demand curves (and thus separate prices). The New York Control Area (NYCA) capacity market covers all of New York State. In addition, New York City (NYC), Long Island (LI), and the Lower Hudson Valley (LHV) consisting of Zones G through J (see Figure 2 below) have their own capacity markets to address generation concerns particular to those areas.[5] NYCA capacity prices set a floor on NYC, LI, and LHV prices, and LHV capacity price set a floor on NYC prices. NYISO administers capacity markets for these four areas during six-month summer (May through October) and winter (November through April) periods.

2. Potential Impacts on Capacity Markets if IPEC Were Not Available

Capacity prices and volumes in the NYISO capacity markets would be affected if IPEC were not available. As IPEC represents roughly 5 percent of installed statewide capacity, near-term prices in the statewide (NYCA) capacity market would rise significantly if IPEC were not available. Indeed, the loss of 5 percent of New York capacity, particularly in the summer, would consume most of the summer excess capacity New York has experienced. The capacity price impact could be even larger in LHV, because IPEC represents an even larger percentage of total LHV capacity.

The capacity price that clears in each zone is given by the intersection of capacity supply based on bids, measured as excess or deficiency relative to ICAP requirement, and the demand curve.[6] Figure 1 provides a stylized and simplified illustration of the capacity demand curve for NYCA. The horizontal axis represents capacity supply measured as a percentage of the ICAP requirement. If the percentage is above 100 percent, there is an excess of capacity supply relative to the ICAP requirement, and if the percentage is below 100 percent, there is a deficiency of capacity supply relative to the ICAP requirement. In this generic example, the capacity price is zero if capacity supply exceeds the ICAP requirement by 12 percent or more (i.e., if capacity supply is at least 112 percent of the ICAP requirement).

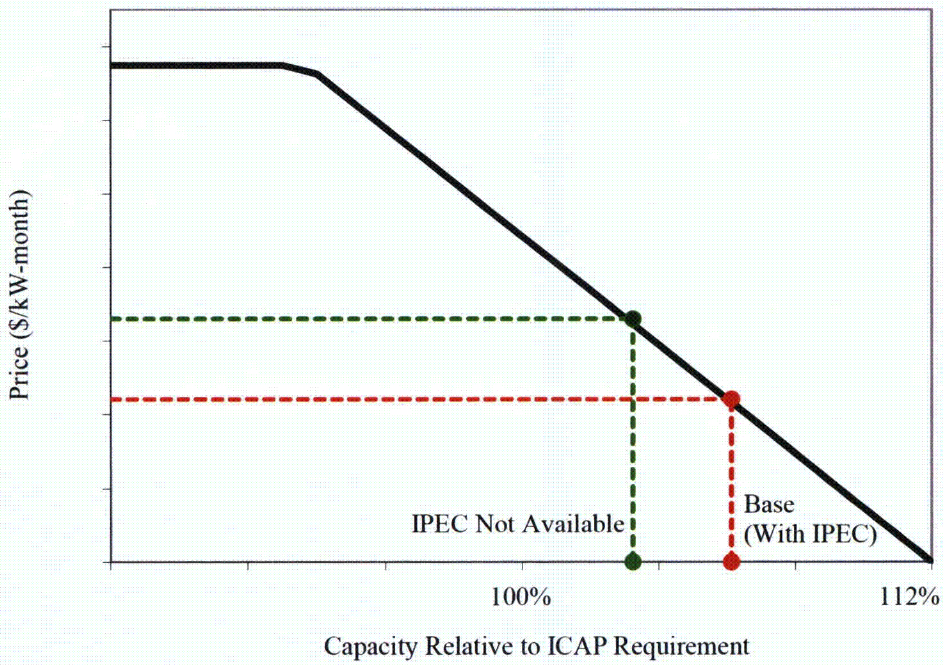
5 The Lower Hudson Valley capacity market area, which NYISO also refers to as the New Capacity Zone (NCZ), will take effect in Summer 2014.

6 As noted above, the system is actually balanced in terms of UCAP, meaning that somewhat higher prices are paid on somewhat lower levels of useful capacity. We have ignored that distinction here, which will not be affected greatly unless the replacement units over time have much different operating capability than the nuclear units.

The demand curve is set by two major parameters: (1) the capacity supply percentage relative to the ICAP requirement at which capacity price falls to $0, which is 112 percent in Figure 1; and (2) the capacity price when capacity supply is 100 percent of the ICAP requirement, which is determined every three years based upon the annual levelized cost of a proxy peaking gas/oil unit in each area less the expected net energy and ancillary service revenues that such unit would earn under equilibrium supply and demand conditions. Connecting these two points yields a demand curve for capacity, i.e., the price of additional capacity at any given level of capacity. As Figure 1 shows, the demand curve also includes a maximum capacity price (although this maximum is usually not reached).

Figure 1 also provides a simple illustration of how the capacity price would be affected if IPEC capacity were not available. The vertical line on the right represents an initial level of capacity supply (relative to the ICAP requirement) with IPEC available. The intersection of this vertical line with the demand curve determines the initial capacity price for this market. The vertical line on the left represents a lower level of capacity (relative to the ICAP requirement) that would result if IPEC were not available. At the lower level, capacity supply would be lower and the price for additional capacity would increase. LSEs would pass the higher capacity payments on to electricity consumers in the form of higher retail rates. Thus, a loss of IPEC capacity would lead to higher capacity prices, higher retail electricity rates, and larger expenditures by electricity consumers.

Figure 1. Illustrative Capacity Market



Note: This is a simplified illustration of the capacity market in New York.

C. Overview of New York State Wholesale Electric Energy Markets

This section discusses how the New York State electricity system, under NYISO, sets wholesale electric energy prices and how electric energy prices would be affected if IPEC generation were not available.

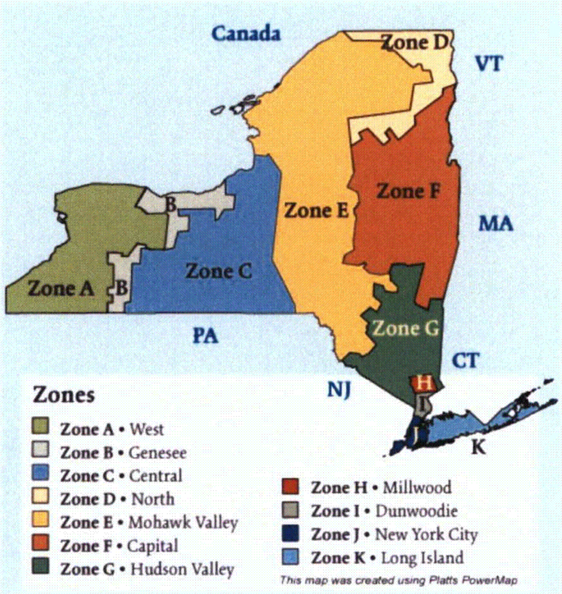
1. Background on New York State Electric Energy Market

Deregulation of wholesale electric energy markets in the United States in the 1990s gave rise to the development of independent system operators (ISOs) and regional transmission organizations (RTOs) as means of administering transmission grids on a regional basis. In 1996, the Federal Energy Regulatory Commission (FERC) issued Order No. 888 requiring that transmission line operators provide non-discriminatory transmission access to electric energy suppliers; the FERC suggested that RTOs or ISOs could be implemented as independent entities tasked with ensuring competitiveness in wholesale markets (EIA 1998 and FERC 2007).

NYISO was formed in 1999 to oversee wholesale electricity market functionality in New York State. NYISO takes bids to supply electric energy from wholesale suppliers. Based on the bids from wholesale suppliers (which generally reflect the short-term marginal cost of generating electric energy, i.e., the cost to a wholesale supplier of producing one additional unit of electric energy), NYISO dispatches generating units and other resources to meet electricity demand in the most cost-effective way, subject to transmission and other electricity system constraints.

NYISO manages bids and transmission wholesale energy markets. Figure 2 shows the zones within the New York electricity system. In this system, a location-based marginal price indicates the price of wholesale electric energy at a specific location, based on the wholesale market bids accepted by the ISO and the transmission costs, congestion, and other constraints specific to that location.

Figure 2. NYISO Zones

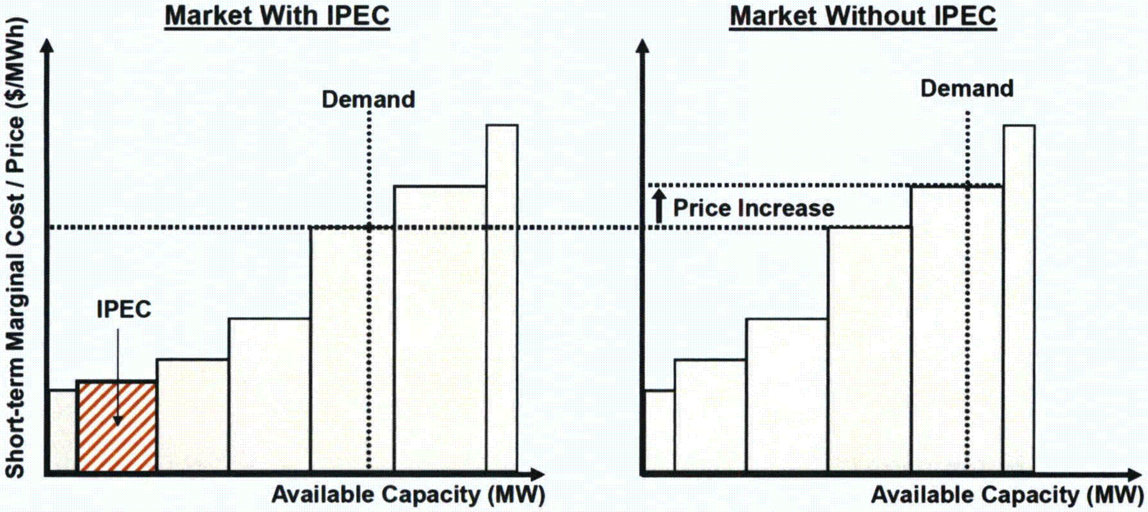


2. Potential Impacts on Energy Markets if IPEC Were Not Available

Because of their lower marginal cost of generation and operating characteristics, nuclear facilities are routinely deployed as baseload facilities, and therefore typically provide power that is consumed by customers at all times of the day and year. If IPEC were not available, other plants would need to provide replacement energy. At most times, generators that would provide replacement energy would operate at higher marginal costs, leading to increases in wholesale electricity prices. The higher wholesale energy prices would lead to higher electricity retail rates and larger electricity expenditures for consumers.

Figure 3 provides a stylized and simplified illustration of the potential effect of loss of IPEC generation on the electricity price in a given demand period. The left half of the figure represents a situation with IPEC present in the market. Each individual rectangle represents a generating facility, with the facilities arranged according to their marginal cost of generation. The lowest-cost units (typically including nuclear units) toward the left side of each figure below are among those dispatched in all demand periods. The market price is set as the marginal cost of generation for the last unit dispatched to meet demand in that period (i.e., where the vertical "Demand" line intersects with the supply stack that reflects available capacity). The right half of the figure illustrates the situation without IPEC. The removal of IPEC means that a more costly unit would need to be dispatched in this example in order to meet demand, thus causing the wholesale market price to increase.

Figure 3. Conceptual Illustration of Wholesale Electricity Price Effects if IPEC Were Not Available



Several features of IPEC tend to magnify the potential effects on electric energy prices if IPEC were not available compared to the effects if other facilities were not available. First, as a baseload unit, IPEC generally operates at full capacity except during specific outage periods, and thus the price increases would occur in virtually all demand periods. Second, IPEC has a large generating capacity, and thus loss of its generation is likely to lead to increases in wholesale prices. Third, since IPEC is in a capacity-constrained region (southeastern New York State), the potential replacement power (to the extent available) is generally more costly and thus the potential price increases required to induce replacement generation would be relatively large.

III. Impacts on New York State Electricity System Reliability if IPEC Were Not Available

This chapter provides information on the reliability impacts if IPEC were not available. We begin with summaries of independent studies that have evaluated the potential effects on New York electricity system reliability if IPEC were not available. We then summarize the ongoing Reliability Contingency Plan (RCP). As noted below, the PSC recently has approved Con Edison's proposals for three transmission projects and an incremental energy efficiency program in New York City as part of the RCP (PSC 2013a). The final section summarizes our assessment of the market-related adjustments that could be made to meet reliability requirements in the near term if IPEC were not available. These assumptions and our methodology are discussed in detail in Appendix A. Our assessments of price impacts in the following chapter presume these near-term adjustments are made because New York State must meet applicable reliability requirements.

A. Independent Assessments of Reliability Impacts if IPEC Were Not Available

Two independent entities—the National Research Council and NYISO—have developed assessments of the potential effects on reliability if IPEC were not available.

1. National Research Council

In 2003, Congress asked the National Research Council (NRC) of the National Academies to form a committee to evaluate the feasibility and desirability of alternative means of replacing the generation and capacity that IPEC currently provides to the New York State electricity system. NRC (2006) provides an evaluation of the reliability implications of loss of IPEC under alternative scenarios. Its modeling "included additional, aggressive programs to improve efficiency of electricity use and stronger demand-side measures to reduce peak demand" (p. 62), but nonetheless found that loss of IPEC could result in major reliability problems.

The first modeling case in NRC (2006) assumed substantial capacity growth before and after the loss of IPEC, but no incremental new capacity added specifically to address the loss of IPEC. In this case, the committee determined that the loss of IPEC would raise reliability risks "to unacceptable levels" (p. 62), including a loss-of-load expectation (LOLE) more than 13 times greater than the standard.

NRC also developed a scenario in which a combination of aggressive demand-side measures and new capacity would be added to maintain an acceptable LOLE despite loss of IPEC. The scenario relied on addition of over 1,000 MW of gas-fired generation capacity in New York City and additional wind capacity around New York City (beyond baseline capacity additions). As the NRC notes,

> "[i]dentifying the generation and transmission system capability that must be provided to replace Indian Point is much easier than determining whether it

actually would get built when needed. All these measures would take time to implement, and several factors may converge to make it even more difficult" (NRC 2006, p. 73).

2. New York Independent System Operator

In its most recent Reliability Needs Assessment (RNA) published in September 2012, NYISO evaluated risk scenarios that could adversely affect the reliability of the New York electricity system. NYISO concluded:

> "Reliability violations of transmission security and resource adequacy criteria would occur in 2016 if the Indian Point Plant were to be retired by the end of 2015 (the latter of the current license expiration dates) using the Base Case load forecast assumptions.
>
> "The Indian Point Plant has two base-load units...located in Zone H in Southeastern New York, an area of the State that is subject to transmission constraints that limit transfers in that area as demonstrated by the reliability violations in the Base Case and Econometric Forecast Scenario. Southeastern New York, with the Indian Point Plant in service, currently relies on transfers to augment existing capacity, and load growth or loss of generation capacity in this area would aggravate those transfer limits. ...
>
> "Transfer limit analysis was performed with both Indian Point units out-of-service (i.e. beginning 2016), and it was assumed all other generation capacity in Zones G through I would be fully dispatched, supporting Southeastern New York load. The analysis shows that, under typical load conditions, the ability to transfer power to Zone J and Zone K would be limited by the upstream UPNY-SENY interface. If the Indian Point Plant were to be retired and new generation interconnected below the UPNY-SENY interface without proper system reinforcement, the UPNY-ConEd and I to J and K interface may be constrained by voltage or thermal limits. ...
>
> "For the Base Case load forecast, LOLE was 0.48 in 2016, a significant violation of the 0.1 days per year criterion. Beyond 2016, due to annual load growth the LOLE continues to escalate for the remainder of the Study Period reaching an LOLE of 3.63 days per year in 2022" (NYISO 2012, pp. 42-43).

Thus, NYISO has concluded that loss of IPEC could have significant adverse impacts on electricity system reliability in New York State. NYISO reiterated this conclusion in the 2013 Power Trends report (NYISO 2013b, pp. 41-43) and in testimony to the New York State Senate Energy and Telecommunications Committee (NYISO 2013c). In *the 2013 Power Trends* report, NYISO noted:

> "To meet reliability requirements, replacement resources have to be in place prior to a closure of the Indian Point Energy Center. Failure to do so would have

serious reliability consequences, including the possibility of rolling customer blackouts" (NYISO 2013b, p. 43).

B. Reliability Contingency Plan

The studies described above (and previous versions of NYISO studies) indicate that substantial system investment would be necessary to prevent violations of New York State's reliability requirement (measured as LOLE) if IPEC were not available to the electricity system. As noted, the PSC's ongoing RCP proceeding was initiated to develop a plan concerning IPEC-related system needs in the event of IPEC becoming unavailable.

The PSC initiated the RCP proceeding in November 2012 through an order directing Con Edison and the New York Power Authority (NYPA) to develop a contingency plan for maintaining electricity system reliability if IPEC were to retire (PSC 2012). Potential elements of these plans could include transmission system expansions to allow southeastern New York to import more power, generation capacity additions in the region, and demand reduction programs or energy efficiency initiatives. The initial order called for Con Edison and NYPA to submit their plans to the PSC by February 2013 for review.

The plan submitted by Con Edison and NYPA proposed several measures to address reliability concerns if IPEC were to retire (Con Edison and NYPS 2013). These proposals included three transmission system expansion projects: (1) a new high-voltage transmission line between Ramapo and Rock Tavern in the Hudson Valley; (2) improvements to transmission lines between Marcy and Coopers Corners in the Mohawk Valley; and (3) improvements to transmission lines between Staten Island and neighboring areas. In addition, the power companies proposed 100 MW of new energy efficiency programs and a solicitation process for other power companies to build and operate alternative new generation and transmission projects. Con Edison and NYPA specified that each element of their plans could be completed by June 1, 2016 (the first summer after both current NRC licenses for the two IPEC units expire).

In November 2013, the PSC accepted the elements of Con Edison and NYPA's proposal (PSC 2013b). The PSC concluded that the three transmission projects described above were "no regrets" projects, i.e., they would have larger benefits than costs even if IPEC were to continue operating. In addition to the original 100 MW of proposed new energy efficiency programs, the PSC took into account plans for 25 MW of combined heat and power (CHP) resources and 60 MW of demand reduction programs identified by the New York State Energy Research and Development Authority (NYSERDA) and NYPA that had not been included in NYISO's 2012 RNA. The PSC noted that many proposals had been submitted by other power companies to build and operate new generation and transmission projects to mitigate the adverse reliability impacts were IPEC to become unavailable but took no action on these proposed projects.

The PSC order from November 2013 also recognizes that market forces would play an important role in electricity system responses to potential IPEC retirement. The PSC noted that higher expected capacity prices in the future resulting specifically from two initiatives underway at NYISO, with or without IPEC in the electricity system, could provide economic incentive for certain projects (PSC 2013b, pp. 6-7). Specifically, the PSC stated that "market conditions are changing and may result in the development of market-based solutions" (PSC 2013b, p. 22).

C. Potential Responses if IPEC Were Not Available

As noted above, the New York State electricity system is a market system. Generation resources are developed, maintained, and operated in response to market prices and opportunities. While we report separately the impact of IPEC unavailability on capacity and energy prices, the decisions that market participants would make with respect to developing, maintaining and operating generation resources if IPEC were not available would be influenced by opportunities in both capacity and energy markets.

In order to model capacity and wholesale electricity prices accurately, we need to make certain assumptions to first ensure that steps are taken to meet reliability requirements in New York State. We provide background on specific potential responses if IPEC were not available in Appendix A. We developed our modeling assumptions based on the requirement to maintain capacity supply at (or above) the ICAP requirement in each capacity market and the assumptions seem reasonable based on financial evaluations as described in Appendix A. We also summarize these modeling assumptions in Appendix B on capacity market analyses and in Appendix D on PROMOD inputs.

As a result of these presumed actions and the transmission and increased energy efficiency that will proceed in the baseline as a result of the RCP (that we assume will be implemented for purposes of this analysis), the potential responses would be sufficient to enable New York to meet reliability requirements if IPEC were not available. However, the energy price, capacity price, consumer expenditure and environmental impacts of IPEC unavailability would still be significant. The remainder of this report presents quantified impacts for these measures.

IV. Impacts on New York State Capacity and Wholesale Electric Energy Prices if IPEC Were Not Available

This chapter provides the results of our analyses of the effects on capacity and wholesale electric energy prices in the period from 2015 to 2019 if IPEC were not available. As noted in the prior chapter, these empirical results presume that adjustments are made to meet reliability requirements.

A. Electricity Capacity Price Impacts

This section describes our methodology and results for estimating the impacts on capacity prices if IPEC were not available. Appendix B provides complete detail of our capacity analysis and results.

1. NERA Methodology

Our methodology to estimate the impacts on capacity prices if IPEC were not available is based upon the demand curve described in Chapter II. This formulation involves several empirical steps. First, we estimate the demand curve that will prevail during the relevant period, from 2015 to 2019. Second, we estimate the minimum required level of capacity and the anticipated actual level of capacity. Third, we calculate the amount of capacity clearing the curve and the price with and without IPEC. We do this separately for a summer month and a winter month (because of the differences in projected capacity ratings and hence supply). To estimate the annual impact, we multiply the summer and winter monthly results by six and add these summer and winter totals.

In addition, we consider the three transmission upgrades outlined in the RCP to take effect in the base line for purposes of this analysis and contribute 600 MW of capacity support in the LHV capacity zone as discussed in the previous chapter (PSC 2013a).

In the scenario where IPEC would become unavailable, the level of required capacity in NYC will likely change based on conclusion drawn from the NYISO 2005 voltage analysis. The local capacity requirement in NYC is essentially a function of the peak load less the import capability. IPEC becoming unavailable reduces the possible imports into NYC and therefore local capacity would need to increase to make up the difference. We therefore increase the ICAP requirement for NYC by 500 MW in the scenario without IPEC.

Hence the unavailability of IPEC would have two impacts. First, the New York State capacity supply would be reduced, causing statewide capacity prices to rise. Second, the amount of capacity required to be purchased against the NYC demand curve would increase because the required amount of local capacity relative to load would increase. This would result in higher capacity prices for the NYC locality if other mitigating actions were not taken.

2. New York Control Area (Statewide) Capacity Price Impacts

Table 2 below shows estimated capacity prices in NYCA in summer months. For this market, capacity prices would increase between 32 and 72 percent.

Table 2. NYCA Capacity Price Increases (nominal $/kW-month): Summer

		IPEC Not Available		
	Base	**Price**	**Increase**	**% Increase**
2015	$4.42	$7.61	$3.20	72%
2016	$5.51	$8.74	$3.23	59%
2017	$6.24	$9.27	$3.02	48%
2018	$6.31	$8.88	$2.57	41%
2019	$7.19	$9.53	$2.34	32%

Source: NERA calculations as explained in text

Table 3 shows estimated capacity prices in NYCA in winter months. For this market, capacity prices would increase between 48 and 105 percent.

Table 3. NYCA Capacity Price Increases (nominal $/kW-month): Winter

		IPEC Not Available		
	Base	**Price**	**Increase**	**% Increase**
2015	$3.05	$6.26	$3.21	105%
2016	$4.13	$7.37	$3.24	79%
2017	$4.85	$8.13	$3.29	68%
2018	$4.89	$7.64	$2.74	56%
2019	$5.76	$8.53	$2.77	48%

Source: NERA calculations as explained in text

3. Regional Capacity Price Impacts

Table 4 shows estimated capacity prices in NYC in summer months. For this market, capacity prices would increase between 6 and 27 percent.

Table 4. NYC Capacity Price Increases (nominal $/kW-month): Summer

		IPEC Not Available		
	Base	Price	Increase	% Increase
2015	$20.39	$22.11	$1.72	8%
2016	$23.10	$24.73	$1.63	7%
2017	$25.29	$26.86	$1.57	6%
2018	$21.83	$27.83	$5.99	27%
2019	$24.33	$28.39	$4.07	17%

Source: NERA calculations as explained in text

Table 5 shows estimated capacity prices in NYC in winter months. For this market, capacity prices would increase between 14 and 70 percent.

Table 5. NYC Capacity Price Increases (nominal $/kW-month): Winter

		IPEC Not Available		
	Base	Price	Increase	% Increase
2015	$9.74	$11.97	$2.23	23%
2016	$12.38	$14.51	$2.13	17%
2017	$14.46	$16.53	$2.07	14%
2018	$10.90	$18.56	$7.66	70%
2019	$13.31	$20.94	$7.63	57%

Note: Dollar values are in nominal dollars.
Source: NERA calculations as explained in text

Table 6 shows estimated capacity prices in LHV in summer months. Shading indicates that LHV prices would be bound below in the base scenario by NYCA prices. For this market, capacity prices would increase between 117 and 265 percent.

Table 6. LHV Capacity Price Increases (nominal $/kW-month): Summer

		IPEC Not Available		
	Base	Price	Increase	% Increase
2015	$4.42	$16.10	$11.69	265%
2016	$5.51	$18.41	$12.90	234%
2017	$6.24	$19.04	$12.80	205%
2018	$6.31	$14.88	$8.57	136%
2019	$7.19	$15.60	$8.41	117%

Note: Shading indicates that LHV prices would be bound below by NYCA prices.
Source: NERA calculations as explained in text

Table 7 shows estimated capacity prices in LHV in winter months. Shading indicates that LHV prices would be bound below in the base scenario in all years and in 2015 if IPEC were not available. For this market, capacity prices would increase between 85 and 216 percent.

Table 7. LHV Capacity Price Increases (nominal $/kW-month): Winter

		IPEC Not Available		
	Base	Price	Increase	% Increase
2015	$3.05	$9.63	$6.58	216%
2016	$4.13	$11.90	$7.77	188%
2017	$4.85	$13.67	$8.82	182%
2018	$4.89	$9.05	$4.15	85%
2019	$5.76	$11.02	$5.26	91%

Note: Shading indicates that LHV prices would be bound below by NYCA prices.
Source: NERA calculations as explained in text

B. Wholesale Electric Energy Price Impacts

This section describes our methodology and results for estimating the impacts of IPEC not being available on wholesale electric energy prices.

1. NERA Methodology

Our estimates of electricity prices and consumer expenditures were developed using PROMOD IV, which was described above and in more detail in Appendix C. The inputs and methodology used in the modeling are described in detail in Appendix D, but are consistent with the reliability and capacity assumptions detailed in Appendices A and B. PROMOD generates estimates of wholesale prices for each hour of our modeling period, with separate estimates for the eleven zones defined by NYISO (as described below). We calculate the monthly average price in each zone as the average of the hourly prices within the month. To convert the monthly price streams to average annual prices, we use the average of the monthly prices, with each month weighted according to its share of the year's total electricity demand in the relevant zone.

The electricity market zones in NYISO are shown above in Figure 2. IPEC is located in NYISO zone H. For ease of display, we combine zones A through F into a single category called "Upstate/Western" for tables in this report. This aggregated regional price is the average of the annual prices in each of the six zones, with each zone weighted by its share of the total electricity demand in the area. Zones G through K (i.e., southeastern New York State) are reported individually.

2. Results for Wholesale Electric Energy Prices

This section presents the wholesale electricity price results from our modeling with PROMOD IV. We begin with statewide average prices and then summarize results by region within New York State for the first and last years of the modeling period (2015 and 2019).

a. Statewide Wholesale Electric Energy Price Impacts

Table 8 presents our estimates of the changes in New York State average wholesale electric energy prices from 2015 to 2019 if IPEC generation were not available. The price increases range from $2.27 to $2.57 per MWh.[7] Based on average baseline statewide projected baseline wholesale prices of about $39 per MWh, these price changes represent increases of about 6 percent.

Table 8. NYS Wholesale Electricity Price Increases (2012$/MWh)

		IPEC Not Available		
	Base	Price	Change	% Change
2015	$37.88	$40.26	$2.39	6.3%
2016	$38.34	$40.91	$2.57	6.7%
2017	$39.05	$41.37	$2.32	5.9%
2018	$39.09	$41.36	$2.27	5.8%
2019	$39.90	$42.29	$2.39	6.0%

Source: NERA calculations as explained in text

b. Regional Wholesale Electric Energy Price Impacts

This section provides estimates of impacts in wholesale electric energy prices by region within New York State over the modeling period for the first year (2015) and last year (2019) of our modeling period. Table 9 provides the results for 2015 and Table 4 provides the results for 2019. The price increases are greatest in the densely populated southeastern New York region. For example, wholesale electricity prices in New York City in 2015 are projected to increase by 9.3 percent if IPEC were not available, compared to 6.3 percent for the state as a whole.

[7] All dollar values in this report are constant 2012 dollars except where noted as nominal dollars. We converted nominal dollars to constant 2012 dollars using projected GDP price deflators in OMB (2013, p. 6).

Table 9. NYS Wholesale Electricity Price Increases by Region in 2015 (2012$/MWh)

		IPEC Not Available		
	Base	Price	Change	% Change
Upstate/Western	$34.42	$35.33	$0.90	2.6%
Hudson Valley	$39.85	$43.38	$3.53	8.9%
Millwood	$41.24	$45.06	$3.82	9.3%
Dunwoodie	$39.93	$43.65	$3.72	9.3%
New York City	$39.93	$43.66	$3.72	9.3%
Long Island	$41.53	$44.17	$2.64	6.3%
State	$37.88	$40.26	$2.39	6.3%

Note: "Upstate/Western" refers to NYISO zones A, B, C, D, E, and F.
Source: NERA calculations as explained in text

Table 10 provides price results for 2019. In this year, wholesale electricity prices in New York City are projected to increase by 9 percent if IPEC were not available compared to 6 percent for the state as a whole.

Table 10. NYS Wholesale Electricity Price Increases by Region in 2019 (2012$/MWh)

		IPEC Not Available		
	Base	Price	Change	% Change
Upstate/Western	$36.02	$36.85	$0.83	2.3%
Hudson Valley	$42.09	$45.29	$3.20	7.6%
Millwood	$43.67	$47.49	$3.83	8.8%
Dunwoodie	$42.20	$46.01	$3.81	9.0%
New York City	$42.20	$45.99	$3.79	9.0%
Long Island	$43.86	$46.66	$2.80	6.4%
State	$39.90	$42.29	$2.39	6.0%

Note: "Upstate/Western" refers to NYISO zones A, B, C, D, E, and F.
Source: NERA calculations as explained in text

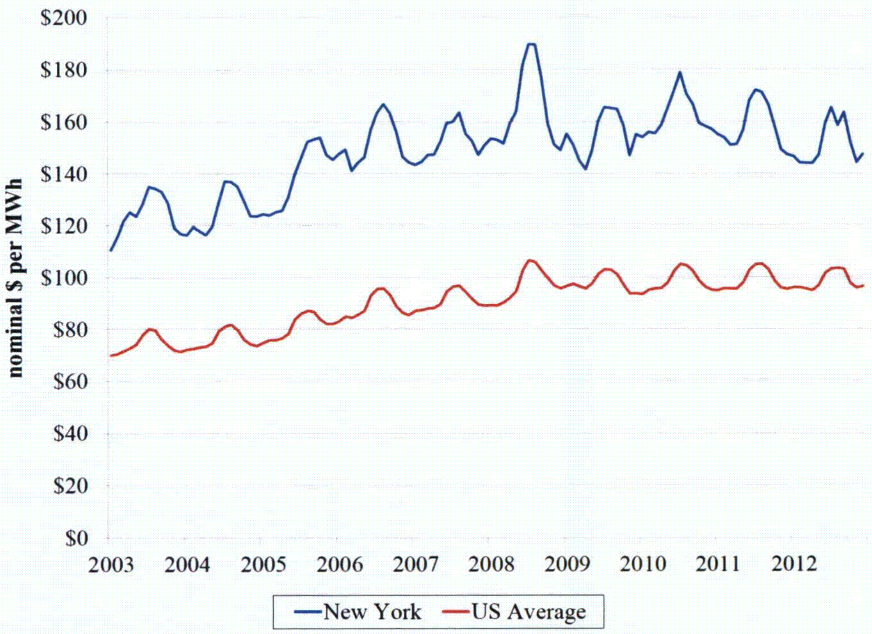
V. Impacts on New York State Consumer Electricity Expenditures if IPEC Were Not Available

This chapter uses the price impact results from the previous chapter to develop estimates of the increased consumer expenditures for electricity if IPEC were not available. The consumer impacts include the effects of increases in wholesale electric energy prices as well as the effects of increases in capacity prices. The impacts do not, however, include any costs for constructing or reactivating facilities to meet reliability requirements that would be required in addition to market prices.

A. Background on New York State Retail Electricity Prices

New York State retail electricity prices are among the highest in the country even with the low-cost power provided by IPEC. Figure 4 shows average monthly retail electricity prices in New York State and the United States from 2003 to 2012. On average over this period, New York State retail electricity prices have been about 65 percent higher than U.S. prices. Note that these retail electricity prices include the costs of the commodity itself (wholesale electricity), transmission, and distribution.

Figure 4. NYS and US Average Monthly Retail Electricity Prices



Source: EIA (2013a)

B. Consumer Expenditure Impacts due to Capacity Price Increases

As discussed above, load-serving entities (LSEs) pass capacity payments on to electricity consumers in the form of higher retail rates. This section shows the estimated increases in electricity expenditures by New York State consumers due to capacity price increases if IPEC were not available.

1. Statewide Capacity Payment Impacts

The figure below presents information on increases in statewide capacity payments if IPEC were not available. These payments are the sum of summer period payments (during the six months from May to October) and winter period payments (during the six months from November to April). If IPEC were not available, the increase in annual capacity payments would range from about $1.2 billion to almost $1.6 billion per year. This increase in required capacity payments by LSEs would be passed on to New York State electricity customers in the form of higher electricity prices. Over the six-year period, increased expenditures related to capacity price effects would total nearly $7 billion if IPEC were not available.

Figure 5. NYS Capacity Expenditure Increases under IPEC Not Available Scenario

Source: NERA calculations as explained in text

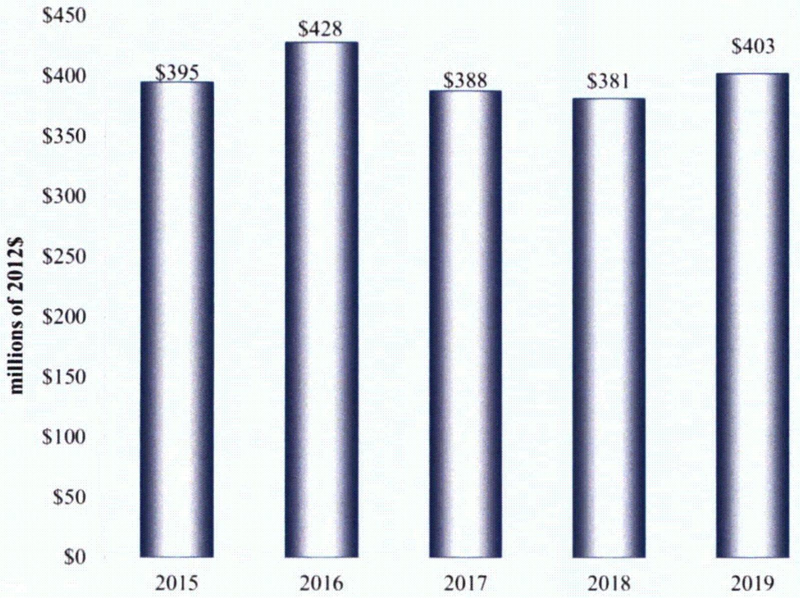
C. Consumer Expenditure Impacts due to Wholesale Electric Energy Price Increases

Increases in wholesale electricity prices would lead to increases in retail electricity prices and thus to increases in electricity expenditures for New York State consumers. This section summarizes results both for New York State as a whole and for consumers within various regions of the state.

1. Statewide Electricity Expenditure Impacts

Figure 6 shows the increases in consumer electricity expenditures if IPEC were not available based on wholesale electric energy price impacts. New York State consumers would pay substantially more for electricity without IPEC. Annual expenditures would increase between $381 million and $428 million. Over the six-year period, increased expenditures would total $2 billion if IPEC were not available.

Figure 6. NYS Electricity Expenditure Increases if IPEC Were Not Available



Source: NERA calculations as explained in text

2. Regional Electricity Expenditure Impacts

The tables below provide detailed geographical results for the first year (2015) and last year (2019) of our modeling period. Table 11 displays the regional impacts on New York State consumer expenditures if IPEC were not available. New York City consumers, for example, would pay $202 million more for electricity in 2015 if IPEC were not available.

Table 11. NYS Consumer Expenditures Increases for Electricity in 2015 (millions of 2012$)

		IPEC Not Available		
	Base	Expend	Change	% Change
Upstate/Western	$2,376	$2,439	$62	2.6%
Hudson Valley	$405	$440	$36	8.9%
Millwood	$122	$133	$11	9.3%
Dunwoodie	$245	$268	$23	9.3%
New York City	$2,169	$2,371	$202	9.3%
Long Island	$955	$1,015	$61	6.3%
State	$6,271	$6,666	$395	6.3%

Note: "Upstate/Western" refers to NYISO zones A, B, C, D, E, and F.
Source: NERA calculations as explained in text

Table 12 displays results for 2019. In that year, New York City electricity expenditures would increase by $210 million if IPEC were not available.

Table 12. NYS Consumer Expenditures Increases for Electricity in 2019 (millions of 2012$)

		IPEC Not Available		
	Base	Expend	Change	% Change
Upstate/Western	$2,509	$2,567	$58	2.3%
Hudson Valley	$434	$467	$33	7.6%
Millwood	$131	$143	$12	8.8%
Dunwoodie	$264	$288	$24	9.0%
New York City	$2,334	$2,544	$210	9.0%
Long Island	$1,050	$1,117	$67	6.4%
State	$6,722	$7,125	$403	6.0%

Note: "Upstate/Western" refers to NYISO zones A, B, C, D, E, and F.
Source: NERA calculations as explained in text

D. Total Consumer Expenditure Impacts

The impacts on total NYS consumer expenditures if IPEC were not available are shown in Figure 7. If IPEC were not available, New York State consumers would pay increased expenditures that range from about $1.6 billion to about $2.0 billion per year over the period. The total increase in New York State consumer payments for electricity from 2015 to 2019 is projected to be almost $9 billion if IPEC were not available. As noted above, this does not include any costs for bringing the presumed resources to meet reliability requirements into the electricity system in addition to costs that would be covered by market revenues.

Figure 7. NYS Total Consumer Expenditure Increases under IPEC Not Available

Source: NERA calculations as explained in text

VI. Impacts on Greenhouse Gas Emissions, Air Quality, and Fuel Diversity Goals if IPEC Were Not Available

This chapter provides information on the implications for climate change, air emissions, and fuel diversity goals if IPEC were not available. These results are based upon the electricity market modeling with PROMOD IV.

A. Greenhouse Gas Emission Impacts

Increases in fossil-fired electricity generation lead to increases in emissions of CO_2, the major greenhouse gas. Leading atmospheric scientists have concluded that emissions of CO_2 and other greenhouse gases are contributing to global climate change, although the pace and impacts of climate change remain highly uncertain.

1. Estimated Increases in CO_2 Emissions

Table 13 displays the effects on initial[8] CO_2 emissions if IPEC were not available. The table presents total emissions for all states participating in the Regional Greenhouse Gas Initiative (RGGI) rather than just New York State. We report broader results because the climate change effects of CO_2 emissions do not depend on the location of the emissions. Since IPEC unavailability would lead to increases in out-of-state generation, as well as in-state generation, it is important to look at the regional effects.

Table 13. Initial Regional Increases in CO_2 Emissions if IPEC Were Not Available (million tons)

		IPEC Not Available		
	Base	Emissions	Change	% Change
2015	115.7	122.3	6.6	5.7%
2016	117.9	124.6	6.6	5.6%
2017	120.5	126.8	6.2	5.2%
2018	119.9	127.0	7.1	5.9%
2019	120.0	126.9	6.9	5.8%

Source: NERA calculations as explained in text

The unavailability of IPEC would increase initial RGGI-area CO_2 emissions by about 6.7 million tons (on an annual average basis).

[8] Initial emissions are those that would take place in the absence of a cap. The base scenario emissions in Table 13 exceed the planned RGGI caps for the relevant years, but covered entities have accumulated a large bank of allowances which would allow their emissions to exceed future caps (RGGI 2013, p. 9).

2. Significance of Increases in CO_2 Emissions

These increases in emissions can be compared with existing regulatory requirements to provide a sense of perspective. New York and eight other Northeastern states have joined together in the RGGI program to reduce emissions of greenhouse gases from the electricity sector. When New York announced the completion of enabling rules for RGGI in 2007, then-governor Eliot Spitzer stated: "Global warming is the most significant environmental problem of our generation, and by helping lead this regional program, we can reduce emissions from power plants – one of the main sources of carbon dioxide emissions in the Northeast," (Spitzer 2007). When Governor David Paterson opened the first RGGI auction of allowances in 2008, he stated: "Global warming is the most pressing environmental issue of our time," and that "by coming together with…other states, New York is showing that we can take our own bold action in reducing greenhouse gas emissions" (Paterson 2008).[9]

The increased emissions if IPEC generation were not available would make it more difficult for New York to achieve its goals under RGGI, and would lead to an increase in allowance prices and therefore an increase in emissions leakage. (Leakage refers to the increase in emissions outside the geographic area covered by the emissions trading program so that the net reduction in emissions is less than the reduction implied by the cap; leakage generally increases as the level of allowance prices increases subject to transmission capability limitations.) Under RGGI, New York electric generators are required to reduce their annual emissions of CO_2 by about 4.8 million tons between 2014 and 2020, from about 35.2 million tons to about 30.4 million tons, with intermediate goals for years in between (NYSDEC 2013a). Thus, the potential annual increases in emissions across the RGGI states from IPEC becoming unavailable are significantly larger than New York State's CO_2 reduction goals for RGGI, as shown below in Table 14.

Table 14. Regional Increases in CO_2 Emissions if IPEC Were Not Available (million tons) Relative to New York State RGGI Reduction Goals

		IPEC Not Available			Change As % of NYS RGGI Goals	
	Base	Emissions	Change	% Change	Annual Goal	Change / Goal
2015	115.7	122.3	6.6	5.7%	0.9	747%
2016	117.9	124.6	6.6	5.6%	1.7	381%
2017	120.5	126.8	6.2	5.2%	2.4	260%
2018	119.9	127.0	7.1	5.9%	3.2	221%
2019	120.0	126.9	6.9	5.8%	4.0	172%

Note: RGGI reduction goals are relative to the state's emissions cap in 2014.
Source: NERA calculations as explained in text

9 RGGI sets an overall cap on emissions, so increases resulting from replacement generation would have to be offset by reductions in emissions from other covered sources. Nonetheless, the initial or gross increases in emissions provide a useful sense of the extent to which replacing the lost output associated with cooling towers at IPEC would make achievement of the caps more difficult and/or more costly.

B. Air Emissions Impacts

In addition to CO_2, the increased reliance on fossil fuels under the IPEC not available scenario would increase NO_x, SO_2, mercury, particulate matter and other emissions.[10] Coal-fired plants emit all five pollutants. Gas-fired units generally emit only CO_2 and NO_x in material quantities. Because the vast majority of the replacement power would likely be generated by gas-fired units, we focus here on NO_x emissions.

Elevated ambient concentrations of fine particles ($PM_{2.5}$) formed from emissions of NO_x and other air pollutants have been linked by the U.S. EPA to a wide range of health effects, ranging from premature death to respiratory disease requiring hospitalization to less significant restrictions on individuals' activities (EPA 2010). NO_x emissions also react with volatile organic compounds to form ground-level ozone, which has been linked to adverse impacts on health and welfare. Over the past decade, federal, regional, and state efforts to control ozone in the eastern United States have focused primarily on reducing emissions of NO_x from power plants and other large stationary sources.

1. Estimated Increases in NO_x Emissions

Table 15 shows the effects on emissions of NO_x in New York State if IPEC were not available. On an annual average basis, the lack of IPEC would increase state electricity NO_x emissions by about 3,000 tons, roughly a 17 percent increase in statewide emissions.

Table 15. NYS NO_x Emissions Increases (tons)

		IPEC Not Available		
	Base	Emissions	Change	% Change
2015	17,723	20,841	3,119	18%
2016	17,574	20,867	3,292	19%
2017	18,203	21,562	3,359	18%
2018	17,792	20,373	2,582	15%
2019	17,815	20,319	2,504	14%

Source: NERA calculations as explained in text

2. Significance of Increases in NO_x Emissions

As part of its state implementation plan (SIP) for the New York Metropolitan Area particulate matter (PM2.5) non-attainment area, New York aims to reduce NOx emissions from relevant point sources, including power plants, by about 1,100 tons between 2007 and 2017 (NYSDEC 2013b, Appendix H, Chapter 3). The table below shows that the increases in NOx emissions if

[10] Emissions of some of these pollutants are covered by a cap-and-trade program that limits total emissions. With a cap-and-trade program, total emissions for sources covered by the cap would not be expected to increase, although the increase in fossil fuel generation and the initial increases in emissions would lead to increases in allowance prices and could lead to increases in overall emissions in some circumstances.

IPEC generation were not available are about three times the NOx reduction goal for New York State's SIP.

Table 16. NYS NO_x Emissions Increases (tons) Relative to New York State SIP Goal

		IPEC Not Available			Change As % of NYS SIP Goal	
	Base	Emissions	Change	% Change	'07-'17 Goal	Change / Goal
2015	17,723	20,841	3,119	18%	1,100	284%
2016	17,574	20,867	3,292	19%	1,100	299%
2017	18,203	21,562	3,359	18%	1,100	305%
2018	17,792	20,373	2,582	15%	1,100	235%
2019	17,815	20,319	2,504	14%	1,100	228%

Note: NO_x SIP goal is reduction of 1,100 tons from point sources (including power plants) from 2007 to 2017.
Source: NERA calculations as explained in text

C. Fuel Diversity Impacts

Regulators in New York State have raised concerns for many years about the state's reliance on natural gas-fired generation, especially in downstate areas, and about the adverse implications for fuel diversity if IPEC were not available. A 2008 NYISO white paper on fuel diversity stated that "comparatively limited downstate fuel diversity poses certain risks for the New York City and Long Island areas" (NYISO 2008, p. 3-6) and that "closure [of IPEC] could exacerbate New York City's existing dependence on natural gas for power production" (NYISO 2008, p. 3-6). NYISO's *2013 Power Trends* report notes that the state's reliance of natural gas-fired generation has more than doubled in recent years, from 27 million MWh in 2004 to almost 60 million MWh in 2012 (NYISO 2013b, p. 35). The report also notes that increased reliance on natural gas for power generation means that any disruption in natural gas supply could have significant implications for system reliability, and volatility in natural gas prices could cause large swings in power prices for New York State power consumers (NYISO 2013b, pp. 35-36).

1. Increase in Natural Gas Consumption

Table 17 shows the PROMOD model estimates of the additional natural gas that would be consumed by electricity generators in New York State if IPEC generation were not available. The IPEC unavailability is forecasted to increase New York State natural gas consumption by about 94 million MMBtu on an annual average basis, more than a 18 percent increase in expected electricity sector gas usage. As a point of comparison, the average household in New York State that uses natural gas (generally for heating) consumes about 69 MMBtu per year (EIA 2013b). Thus, unavailability of IPEC would require an increase in natural gas consumption for electricity generation equivalent to the natural gas usage of nearly 1.4 million New York State households.

Table 17. NYS Electricity Sector Natural Gas Consumption Increases (million MMBtu)

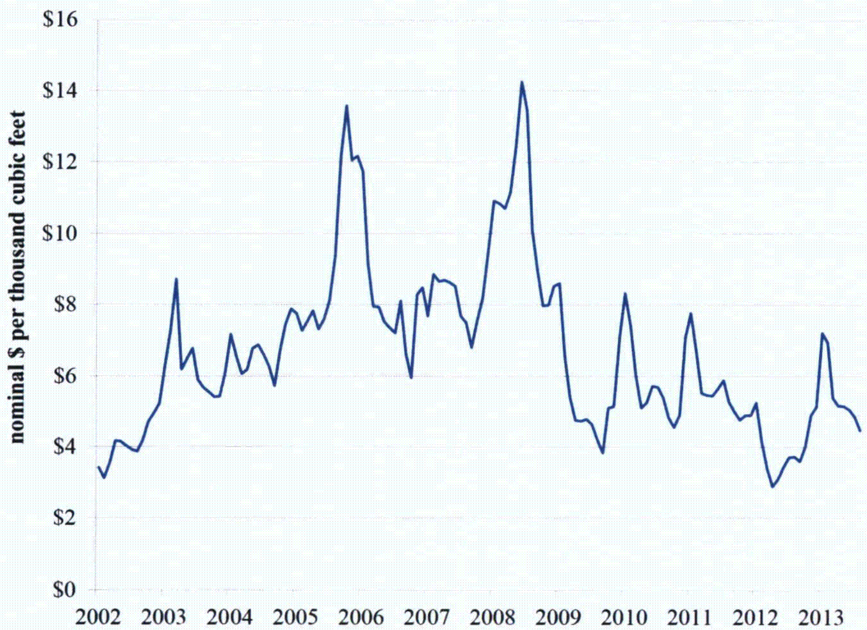
		IPEC Not Available		
	Base	Consumption	Change	% Change
2015	497	593	95	19%
2016	510	601	91	18%
2017	513	611	97	19%
2018	518	611	93	18%
2019	512	608	95	19%

Source: NERA calculations as explained in text

2. Significance of Increased Natural Gas Dependence

As noted above, since natural gas is already the predominant price-setting fuel in New York State, the state's electricity prices are already significantly exposed to changes in natural gas prices, which are highly volatile. Figure 8 shows prices for natural gas delivered to the New York State electricity sector from January 2002 to October 2013. This history shows the significant volatility in natural gas prices, which translates into volatile electricity prices since natural gas-fired generating units set prices in most demand periods in New York State. The increased reliance on natural gas due to the unavailability of IPEC would lead to even greater consumer exposure to natural gas price volatility.

Figure 8. Historical Natural Gas Prices Delivered to NYS Electricity Sector



Source: EIA (2013c)

VII. Conclusions

IPEC is a major element of the New York State electricity system. If IPEC were not available, there would be substantial near-term impacts on system reliability, electricity prices and consumer expenditures, as well as on policy goals for climate change, air quality, and fuel diversity. This section provides a brief summary of our conclusions regarding the adverse near-term electricity market and related impacts if IPEC were not available.

1. *Reliability impacts*. New York electricity system reliability would be compromised if IPEC were not available. Many experts have raised such concerns, including the National Research Council and the NYISO.

2. *Capacity price increases*. If IPEC were not available, capacity supply would decrease, causing a rise in capacity prices. The NYCA would realize a state-wide capacity price increase of between $2.34 and $3.23 per kW-month over the period from 2015 to 2019.

3. *Wholesale electricity prices*. If IPEC were not available, wholesale electricity prices would increase over the period from 2015 to 2019 between $2.27 and $2.57 per MWh, an increase of about 6 percent.

4. *New York State electricity expenditures*. Higher capacity and wholesale electricity prices would mean that New York State consumers would spend over $1.6 billion more on electricity per year on average than they otherwise would over the 5-year near-term timeframe, or a total of almost $9 billion over the period.

5. *Greenhouse gas emissions*. Removal of IPEC would also have important environmental implications. The generation that would replace lost output from IPEC would emit about 6.7 million tons of CO2 per year, an amount significantly greater than New York State's annual reduction goals under the RGGI program. This increase would make meeting the RGGI targets more difficult and costly.

6. *Air emissions*. The increase in NOx emissions if IPEC were not available would be approximately three times the target decrease under the SIP. Thus, attainment of New York State NOx emission reduction goals would be significantly more difficult if IPEC were not available.

7. *Fuel diversity*. Natural gas consumption by New York State electricity generators would increase substantially if IPEC were not available, amplifying existing concerns about the diversity of the state's electric fuel supply. Each year of IPEC unavailability would lead to an average increase in electricity natural gas usage of about 94 million MMBtu, equivalent to the annual natural gas usage of more than 1.4 million New York State households. Natural gas prices are extremely volatile, and natural gas-fired generating units determine New York State electricity prices for most hours of the year. Thus, New

York State electricity customers would be more vulnerable to volatility in electricity pricing if IPEC were not available.

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Appendix A: Responses to Reliability Impacts

This appendix provides information on potential responses to meet the reliability requirements of the New York State electricity system if IPEC were not available, potentially including reactivation of mothballed and retired power plants, construction of new power plants and transmission capacity, and demand response/energy efficiency programs. This appendix summarizes our modeling assumptions related to reliability requirements for our capacity and PROMOD analyses. As described in Appendices B and D, our modeling assumptions are consistently applied to both the capacity and PROMOD analyses.

A. Reliability Contingency Plan

As discussed in the report body, the New York State Public Service Commission (PSC) has initiated a Reliability Contingency Plan (RCP) proceeding to develop a contingency plan concerning IPEC-related system needs in the event of IPEC becoming unavailable. Con Edison and the New York Power Authority (NYPA) submitted a plan proposing three transmission projects and an incremental energy efficiency program as part of the RCP proceeding. The PSC has concluded that these transmission projects and demand response/ energy efficiency programs were "no regrets" projects that provided benefits larger than costs irrespective of IPEC's future operating status. The PSC has accepted these measures as plan components. The transmission owners will file at FERC concerning the cost allocation and cost recovery for the projects.

The three transmission projects are projected to provide 600 MW of additional transmission capacity, which is less than one third of IPEC capacity (PSC 2013a). These projects would benefit the UPNY/SENY interface, as the projects would allow for more power transfers.

The RCP proceeding remains open, and the PSC has indicated that is providing time for market solutions to develop. This is consistent with the policy that the state has adopted to rely on markets to meet energy and capacity needs and to use non-market or regulated solutions only when market solutions do not fully address identified reliability system needs, as stated by NYISO in its reliability needs assessments (see, e.g., NYISO 2012).

B. Challenges for Near-Term Responses if IPEC Were Not Available

Substantial lead time is required to plan, permit, and construct new capacity in New York. Experience under the original Article X process suggests this process takes many years. Thus, most projects that have not yet begun that process would probably not be implemented and operational in time to mitigate the reliability shortfall if IPEC were not available within the time period covered by the analysis. With regard to existing units with available capacity not currently being utilized, economic considerations and air emission requirements can limit their potential reactivation if IPEC were not available.

C. Potential Responses to Reliability Concerns

The responses to a near-term IPEC reliability shortfall would have to come from resources that would be available within the five-year time period of the analysis. The resources that could respond and fill the reliability gap resulting from IPEC's unavailability include three potential categories.

- capacity that has been mothballed or retired but retains its permits, interconnection, and deliverability rights and does not otherwise face operating limits, thus could be returned to service on short notice;
- new generation and transmission capacity; and
- expanded (but likely expensive) demand response/energy efficiency programs.

We provide background on specific potential responses if IPEC were not available in the near-term. We describe our modeling assumptions regarding these potential responses in Appendix B, because we base these assumptions on meeting reliability as measured by ICAP requirements in capacity markets. New York will be required to meet its reliability requirements. To the extent that market prices do not support additional capacity if IPEC is not available, regulated costs will also be borne by consumers which are not quantified herein.

1. Reactivation of Mothballed and Retired Power Plants

This section identifies specific power plants in New York State that have recently been derated, taken out of service, mothballed, or retired and could potentially be reactivated if IPEC were not available.

- *Bowline.* Approximately 300 MW of gas/oil-fired capacity at the Bowline plant in Haverstraw (LHV) that is over 40 years old has been unavailable to operate due to physical damage.
- *Astoria GT Units 10 & 11.* Approximately 40 MW of gas-fired capacity at the NRG Astoria power plant in New York City, which had been mothballed but was reactivated in 2013 and therefore its capacity was not reflected in the 2013 Goldbook.
- *Astoria 2 & 4.* Approximately 560 MW of gas/oil-fired capacity at the USPG Astoria power plant in New York City, all of which is over 40 years old, has recently been mothballed.
- *Danskammer.* Over 500 MW of capacity (a mix of natural gas and coal units) at the Danskammer plant in Newburgh (LHV) that is over 50 years old received approval from NYISO and the PSC to retire and dismantle. The PSC, however, recently appears to be reopening the possibility that the facility will delay retirement to ameliorate potential impacts on consumer prices (PSC 2013b).

- *Dunkirk*. Over 500 MW of coal capacity at the Dunkirk plant in Zone A that is over 50 years old has been mothballed or will be mothballed in 2015.

2. Construction of New Power Plants

This section provides background on significant specific power plants that could potentially be constructed in the near-term if IPEC were not available. As discussed above, these construction projects require several years of lead time to acquire permits, arrange fuel supply, and obtain interconnection rights.

- *CPV Valley*. This 677 MW natural gas combined cycle plant in the Lower Hudson Valley has received SEQRA approval and has accepted its cost allocation for transmission upgrades and can interconnect to the NYISO grid with capacity rights. Assuming a three year financing/construction period, the earliest possible date for this unit would be the beginning of 2018.

- *Cricket Valley*. This 1000 MW natural gas combined cycle plant in the Lower Hudson Valley has received SEQRA approval but has not received capacity or energy interconnection rights. It has been assigned about $280 million in interconnection costs and has not accepted this cost allocation due to the interconnection point that it proposed on the system (NYISO 2013a).

- *Berrians*. Approximately 280 MW of natural gas-fired capacity have been proposed for the Astoria site in New York City.

3. Demand Response/Energy Efficiency Programs

As noted above and in the report body, the PSC has approved an incremental demand response/energy efficiency program as part of the RCP proceeding, which we accept as being implemented for the purposes of this analysis. Conceivably, additional new programs could be created to meet reliability requirements if IPEC were not available, including emergency demand response programs, assuming existing programs have not already utilized the available MW for these programs.

D. Specific Presumed Actions

Our modeling assumes that the following actions would be taken (or not taken) to deal with reliability concerns both in the base case (i.e., with IPEC) and in the case if IPEC were not available.

- *Bowline*. For a recent consumer impact analysis, NYISO assumes that 321 MW of damaged capacity at Bowline would return to service (NYISO 2013b, p. 12). We assumed that this capacity would be available beginning in 2015 in the base case and if IPEC were not available.

- *Astoria GT 10 & 11 (NRG) and Astoria 2 & 4 (USPG).* As noted above, our capacity analysis (see Appendix B) indicates that NYC would have a shortfall even in the base case. We assumed that 220 MW at Astoria (units 2, 10, and 11) would return to service in at the start of our study period in 2015 in the base case (note that as mentioned above, Astoria units 10 and 11 will be continue operation as they were reactivated in 2013). This is two years before the projected beginning of a capacity shortfall (2017), but it seems reasonable that some capacity would return to service somewhat early based on higher projected capacity prices than historical prices (see Appendix B).[11] Moreover, we assumed that the 380 MW of capacity at Astoria 4 would return to service in 2018. If IPEC were not available, NYC would have significant shortfalls in all years (because of higher ICAP requirements related to transmission constraints), and we assumed that all 600 MW of relevant capacity at Astoria would be restored to, or continuing service in 2015. For purposes of this analysis we do not speculate as to whether Astoria 4 may return to service earlier in either scenario in order to retain its capacity interconnection service rights. In the event it did, the capacity price impacts of not having IPEC available would likely be much larger than reported herein.

- *Danskammer.* LHV does not have a shortfall of capacity in the base case, so we assume that Danskammer would not reactivate in the base case. If IPEC were not available, LHV would have a shortfall of capacity even with the Astoria reactivations. However, we assume that Danskammer would not reactivate in this case because of operating constraints related to air emissions considerations.

- *Dunkirk.* We assume that this coal plant in Zone A would not reactivate, because of operating constraints related to air emission considerations.

- *CPV Valley.* CPV Valley seems to have the highest likelihood of construction given its status in the permitting and interconnection permitting processes. Whether it would be economic and constructed depends upon many uncertain factors. In the interest of being conservative (i.e., understating the potential impacts on consumer expenditures if IPEC were not available), we assume that CPV Valley would be available at the beginning of 2018. Note that this is an assumption only for purposes of this analysis and does not address factors such as whether the unit would be deemed to be economic for Mitigation Exemption Test purposes or would be subject to an offer floor under the LHV buyer side market power rules.

- *Cricket Valley.* As noted above, Cricket Valley was given a large cost assignment by NYISO and was not included in the October 15 notice on settlements for Class Year 2011 (NYISO 2013c). We assume that Cricket Valley would not be built based upon a rough assessment that it would not likely be economic even if IPEC were not available.

- *Berrians.* NYC would still have small shortfalls in some years if IPEC were not available. We presume that Berrians would not be built based upon a rough assessment that it would not likely be economic even if IPEC were not available. A recent evaluation from Potomac Economics confirmed that the Berrians facility would not be exempt from the Offer Floor

[11] The Astoria 10 and 11 units were returned to service in Summer 2013 (NRG 2013).

and thereby subject to the lower of the Default net CONE and Unit net CONE, should the unit begin operation (Potomac 2013).

- *Demand response programs*. The reactivations described above for Astoria would still leave near-term capacity shortfalls in NYC, LHV, and NYCA in some years if IPEC were not available. For purposes of this analysis, we have assumed that additional demand response would be available. We increase demand response programs in the capacity and PROMOD modeling to make up for near-term shortfalls, as described in Appendices B and D.

Table A-1 summarizes the incremental value in megawatts of our responses for the summer of 2019. Note that LHV values do not include NYC, and NYCA values do not include LHV or NYC. As context for these values, IPEC's capacity is about 2,070 MW.

Table A-1. Incremental Capacity Changes by Capacity Zone (MW)

	Base Case			
	NYC	**LHV**	**NYCA**	**Total**
Generation	600	321	0	921
Demand Response	0	0	0	0
Total	600	321	0	921

	IPEC Not Available			
	NYC	**LHV**	**NYCA**	**Total**
Generation	600	998	0	1,598
Demand Response	214	0	0	214
Total	814	998	0	1,812

Source: NERA calculations as explained in text

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Appendix B: Modeling of Electricity Capacity Price Impacts

This appendix provides background on New York State capacity markets and describes the methodology and inputs that were used to model the impacts on capacity prices if IPEC were not available.

A. Background on New York State Capacity Markets

This section provides background on capacity markets organized and administered by the New York Independent System Operator (NYISO).

1. Rationale for Capacity Markets[12]

Capacity may be less than its socially optimal level in the absence of capacity payments because capacity additions represent a positive externality on the electricity system. As discussed above, disruptions in electricity supply can cause serious economic damage across large sections of the electricity system. As capacity is added in the electricity system, the probability of a disruption in electricity supply decreases and the expected losses associated with breaches in electrical system reliability are reduced. Under energy-only schemes, generators have to take large risks to add capacity and cannot capture the additional value for the broader electric system because system reliability is a "public good," unless the price they are paid includes the true social cost of outages in times of scarcity. Since such payments are usually politically infeasible, virtually every organized power market in the United States exhibits a gap between net revenues from energy markets and the capital costs of investing in new capacity.

There are two main approaches to address the under-investment problem for generation capacity. System administrators can mandate a reserve capacity margin and let participants buy capacity from the least cost providers and demonstrate compliance, or administrators can provide for capacity by making payments based on generators' installed capacity. As discussed below, NYISO uses the second approach. Generators that clear the market are paid for the capacity they make available. The capacity markets are designed so that capacity prices supplement energy-only revenues to allow investors to recoup the fixed capital costs of a new power plant.

2. Evolution of Capacity Markets in NYISO

In New York State, the level of installed capacity (ICAP) required to meet reliability requirements is set by the New York State Reliability Council (NYSRC). NYISO ensures that each load-serving entity (LSE) secures sufficient installed capacity to meet the capacity level established by the capacity market rules. An LSE may be a competitive retailer or a utility (e.g., Consolidated Edison) serving customers who are not served by competitive retailers.

Prior to 2003 each LSE was required to provide the minimum required capacity on a monthly basis. The NYISO would conduct monthly deficiency auctions to ensure that each LSE in need

[12] This section draws on Jaffe and Felder (1996) and Joskow (2006).

of supplemental capacity bought the required minimum. If there was excess capacity, some generators would be unable to sell capacity. This system had a tendency to result in extreme prices (Paynter 2004, pp. 8-9). When there was even a small amount of excess capacity, the clearing price was at or near zero, and when there was a shortage the clearing price was at or near the maximum permitted price. The market was short term, but the capacity entry decision was long term. The demand curve for capacity was effectively a vertical line: the NYISO would pay for the capacity it required, but would pay nothing for any further excess capacity. As a result, there was always either an excess or shortage. To stabilize prices, the NYISO in 2003 implemented the demand curve, as discussed in the following section.

The NYISO administers four separate but interrelated capacity markets for New York City (NYC), Long Island (LI), Lower Hudson Valley (LHV), and the statewide New York Control Area (NYCA).[13] Every summer (May-October) and winter (November-April), the NYISO offers one six-month strip auction, six monthly auctions, and six spot auctions (ICAP manual, section 2.1); participation in the first two auctions is voluntary. The primary reason for the separate summer and winter capacity markets is that net capacity at generation stations typically varies with ambient temperature. (Net capacity is typically highest in winter when low ambient temperatures allow waste heat from generation stations to be removed most efficiently.)

3. Description of Demand Curve

Under the demand curve method each LSE remains responsible for providing capacity and has the opportunity to self-supply capacity or bid to buy capacity in the strip auction and the monthly auctions.[14] However, the amount of installed capacity required is not fixed to the minimum level set by the NYSRC. Instead, each LSE must buy its share of the capacity offered in the aggregate and that clears in the spot auction. For example, if the NYSRC sets a statewide minimum 17 percent reserve margin, but capacity providers (including self-suppliers and purchasers in the strip auctions) provide bids that clear amounting to 21 percent reserve capacity (4 percentage points in excess of the requirement), then LSEs must pay for a 21 percent reserve level. This is implemented through the demand curve, which specifies the price at which NYISO buys offered capacity in the spot auctions (ICAP manual, section 2.1).

An illustration of the demand curve is presented below in Figure B-1. Although the demand curve only directly sets prices in the spot auctions, capacity prices in the other auctions closely track the spot auction price (Paynter 2004, p. 16). Presumably, bilateral transactions also seek to come within the range of these prices generally. Thus we can effectively use the demand curve to predict all near-term capacity prices.

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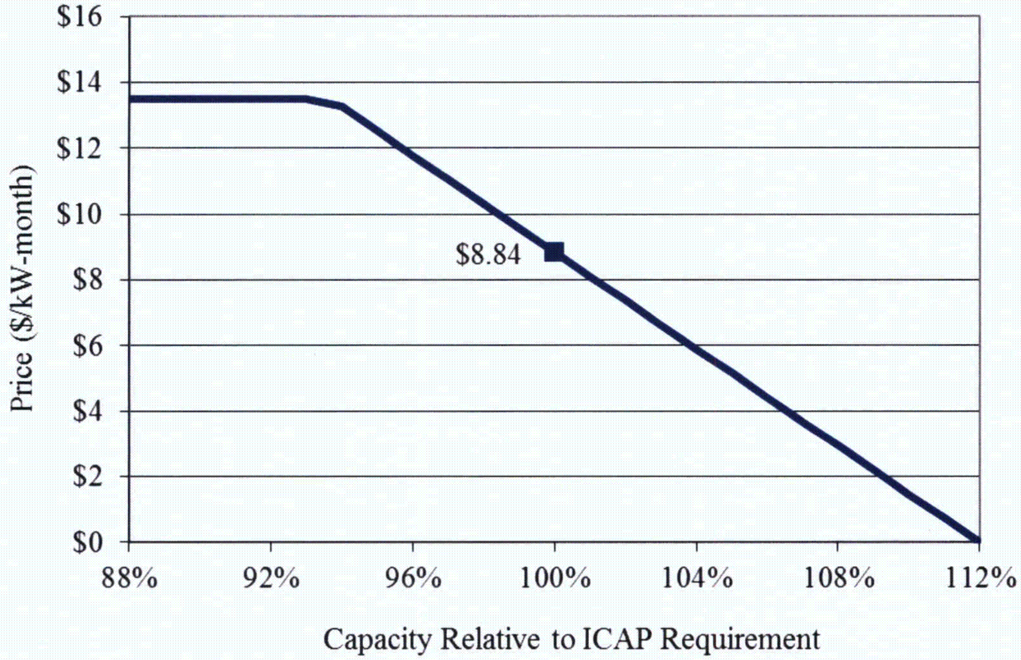
[13] The capacity locality for the Lower Hudson Valley will take effect in May 2014.

[14] These auctions actually function in terms of unforced capacity (UCAP), not ICAP, with distinctions based on unforced capacity and derating for hot conditions. This report ignores this distinction, which introduces substantial complexities without changing any of our conclusions. The results would be exactly the same if new capacity exactly matched the lost nuclear capacity in terms of forced outage and derate. Since these factors are difficult to project, we will assume that there is no additional loss or gain in moving between UCAP and ICAP for the nuclear units. Capacity payments are then the same whether capacity is measured in terms of UCAP or ICAP.



Source: NYISO (2013a, p. 24)

Figure B-1. NYCA 2014/2015 Demand Curve

The 100 percent point represents the NYSRC required capacity level. That level is currently an 18 percent statewide reserve margin or 118 percent of forecast statewide peak load (NYISO 2013a). Each month the offered capacity will be cleared against the curve and the cleared level will be purchased by NYISO. As shown above based on the current structure, on a statewide basis when there is 12 percent more capacity than needed (resulting in an overall statewide reserve margin of 118 percent x 112 percent – 100 percent = 31 percent), the capacity price is zero.

Each LSE must self-supply or buy in the capacity auction the reserve level that clears the auction. Hence if there is a 6 percent statewide excess reserve level relative to the ICAP requirement (resulting in an overall statewide reserve margin of 118 percent x 106 percent – 100 percent = 24 percent), each LSE must buy 124 percent of its own forecasted peak load. The demand curve is designed so that price drops more steeply than volume rises so even when buying excess, total capacity payments decline compared to what would be bought at the minimum level (Paynter 2004, p. 14). The price level on each demand curve changes every year, but is established and known for a three-year period.

As noted above, NYISO has four different capacity markets for NYC, LI, LHV and NYCA. The demand curve in each market reflects the ICAP requirement for that zone. The current ICAP requirements for NYC, LI, LHV and NYCA are 86, 105, 88 (indicative) and 118 percent of projected peak load in each zone (NYISO 2013a), which will be revised in January 2014 with the new levels to be applied to the 2014-2015 Capability Year.

NYC capacity is first cleared against a demand curve that has a target level of 86 percent of NYC load. As with the statewide process, all capacity is cleared against the demand curve and the NYISO may actually buy, for example, 86 percent of NYC load. Given the assumptions in this example, if in the statewide (NYCA) market NYISO buys 124 percent of statewide load, LSEs in NYC would be required to buy capacity equal to 86 percent of NYC peak load from NYC resources clearing on the NYC demand curve as well as 38 percent (124 percent - 86 percent) of NYC peak load from resources outside NYC at the capacity price that clears the NYCA demand curve. The cleared NYC capacity would count toward the statewide purchase level.

In the event that the NYC demand curve were to clear below the statewide (NYCA) demand curve, all NYC capacity would clear against the statewide demand curve and LSEs in NYC would just buy 124 percent of NYC peak load against the statewide demand curve. Unlike the statewide demand curve, which drops to zero at 12 percent excess, the NYC and LI demand curves are less steep and reach zero at 18 percent excess; the LHV demand curve reaches zero at 15 percent excess. The above discussion summarizes how things work prior to the addition of the LHV zone. With the addition of the LHV zone there is another step. If the NYC Demand Curve clears below the LHV curve but above the NYCA curve, all capacity requirements up to the LHV local capacity requirement in NYC would be bought at the higher LHV clearing price.

4. Historical Experience

NYISO has for the last several years been consistently clearing capacity above the minimum required level. This may be due, in part, to the impact of the recession on load. Table B-1 shows capacity levels cleared in the auction statewide (NYCA), New York City (NYC), and Long Island (LI).[15] Clearing levels are usually greater in the winter than the summer because, as noted above, generating stations tend to have higher net capacities in the winter when low ambient temperatures and high air densities allow for more efficient disposal of waste heat.

[15] As noted above, the capacity locality for the Lower Hudson Valley will take effect in May 2014.

Table B-1. NYISO Historical Capacity Supply Relative to ICAP Requirements

Monthly Excess Percent: Summer Average								
	2006	2007	2008	2009	2010	2011	2012	2013
NYCA	7.1%	6.9%	8.5%	8.0%	10.1%	11.7%	9.2%	5.1%
NYC	2.9%	3.1%	10.5%	8.5%	5.0%	9.4%	7.8%	4.2%
LI	8.5%	8.6%	13.8%	12.0%	15.2%	17.8%	14.0%	6.4%

Monthly Excess Percent: Winter Average							
	2006	2007	2008	2009	2010	2011	2012
NYCA	8.9%	8.8%	10.2%	10.4%	11.6%	11.8%	9.5%
NYC	11.0%	13.4%	17.3%	13.3%	14.1%	14.4%	13.9%
LI	13.2%	12.9%	17.4%	18.0%	18.0%	18.0%	17.9%

Source: NYISO capacity auction data

B. Overview of Methodology for Modeling Capacity Price Impacts

The methodology for modeling capacity price impacts in each future year of our analysis period can be summarized in seven steps. Note that we do not model changes in the LI capacity market because it would not be directly affected by IPEC becoming unavailable (and see the discussion below regarding indirect effects through changes in NYCA capacity prices).

1. Estimate demand curve parameters (reference price for 100 percent of ICAP requirement, maximum price, and ICAP percentage corresponding to capacity price of $0) for each future year for each locality (NYCA, NYC, and LHV).

2. Estimate peak demand for each future year for each locality.

3. Estimate ICAP requirements for each future year for NYCA (118 percent of peak demand), NYC (86 percent of peak demand), and LHV (88 percent of peak demand).[16] As discussed below, we include an adjustment to the LHV ICAP requirement in the base scenario and IPEC not available scenario to reflect Con Edison's transmission projects as part of the IPEC Retirement Contingency Plan.

4. Estimate capacity supply in each locality in summer and winter periods, and express capacity supply as a percentage of the ICAP requirement. Capacity supply includes generation units as well as special case resources (SCRs) and external resources (based on unforced capacity delivery rights [UDRs] for NYC and LI). Capacity supply and ICAP requirements differ between the base scenario and IPEC not available scenario because the IPEC unavailability removes IPEC from the electricity system and involves changes to the NYC ICAP requirement, as discussed below.

[16] Current ICAP requirement percentages are assumed to remain constant throughout our analysis period, and the indicative level calculated by NYISO for the upcoming LHV capacity market is presumed to hold.

5. If capacity supply is ever below the ICAP requirement (i.e., less than 100 percent) for any locality in either the base scenario or IPEC not available scenario based on the calculations above, increase capacity supply or decrease peak load (through demand response programs) to achieve the ICAP requirement. Possible modifications to avoid violations of ICAP requirements include:

    a. Reactivate mothballed generation units to increase capacity supply;

    b. Add new generation units to increase capacity supply if feasible and economic; and

    c. Include emergency demand response programs to decrease peak load.[17]

6. Using the demand curve parameters and ICAP percentages calculated above (including any modifications to capacity supply or peak load to avoid violations of ICAP requirements in either the base scenario or IPEC not available scenario), estimate capacity prices in each locality and period. This involves reading the capacity price corresponding to the ICAP percentage for the relevant demand curve for each locality, as shown above in Figure B-1. Note that capacity prices for each low-level locality must be at least as high as capacity prices in higher-level localities that include the low-level localities. Thus, NYC capacity prices must be at least as high as LHV capacity prices, which in turn must be at least as high as NYCA capacity prices.[18]

7. Estimate capacity payments by multiplying each locality's relevant capacity supply by its capacity price. For NYC, the relevant capacity supply is simply NYC capacity supply. For LHV, the relevant capacity supply is LHV capacity supply excluding NYC capacity supply (i.e., LHV capacity payments are based on capacity supply in zones G through I). And for NYCA, the relevant capacity supply is NYCA capacity supply excluding LHV and LI capacity supply (i.e., NYCA capacity payments are based on capacity supply in zones A through F).[19]

As noted above, differences in capacity payments between the base scenario and IPEC not available scenario arise from several different inputs in our calculations. The most fundamental difference is that IPEC does not contribute to LHV and NYCA capacity supply in the IPEC not available scenario. Moreover, the lack of IPEC transmission system support in the IPEC not available scenario leads to an increase in the NYC ICAP requirement (i.e., we assume that

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17 Technically these emergency demand response programs are considered increases in supply, but we analyze them as reductions in demand.

18 Since LI is within NYCA, LI capacity prices must be at least as high as NYCA capacity prices. Indeed, LI capacity prices have been set by NYCA capacity prices in some recent capacity auctions. We do not model any changes in LI capacity payments based on changes in NYCA capacity prices in the IPEC not available scenario.

19 The actual NYISO capacity payment system involves payments by LSEs in lower-level localities based on prices in higher level localities. For example, NYC LSEs make some payments at LHV and NYCA prices based on NYC shares of LHV and NYCA peak loads. This is simply a different way of assigning capacity payment obligations than the calculations described above. Total capacity payments in the base scenario and IPEC not available scenario are the same using our system of calculations as with the system based on LSE obligations.

NYISO would require more capacity supply in NYC because less power could flow into NYC without IPEC providing transmission system support). In addition, the base scenario and IPEC not available scenario differ in some of their modifications to avoid violations of ICAP requirements in certain localities.

C. Data Inputs Based on NYISO Materials

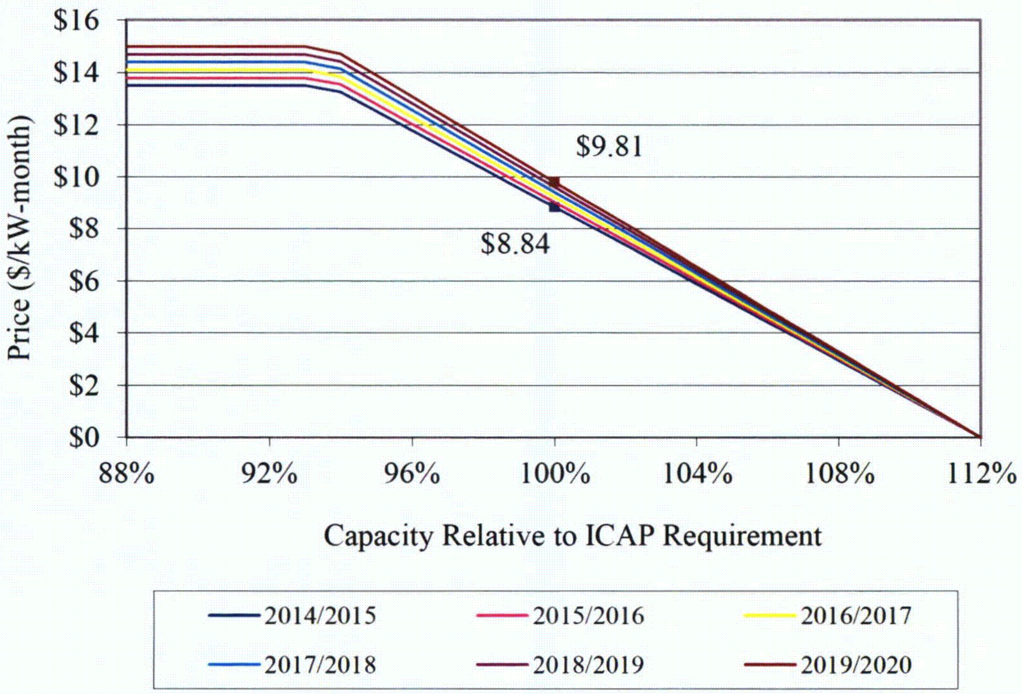
This section describes the data inputs based on NYISO materials (including the demand curve parameters and demand and capacity supply from the Gold Book) for estimating the capacity market impacts of IPEC becoming unavailable. Our modifications to capacity supply and demand to avoid violations of ICAP requirements are described in the following section.

1. Demand Curves

The NYISO Staff on September 6, 2013 published the recommended demand curves for Summer 2014 to Winter 2016/2017.[20] We extended these demand curves to 2019 (including Winter 2019/2020) using linear extrapolation of the maximum clearing price. Figure B-2 shows estimated demand curves for NYCA. Note that the NYCA demand curves fall to zero at a 12 percent excess.

[20] We have used the Demand Curves recommended by NYISO Staff on September 6, 2013. However, based on a report developed by Brattle (Brattle 2013), the NYISO Board on November 27, 2013 filed with FERC proposed lower Demand Curves. The ultimate outcome at FERC is not known at the time of this filing. We show capacity payments based on the lower Demand Curve parameters in Brattle (2013) at the end of this appendix. As shown there, using lower Demand Curves would reduce the price and consumer expenditure impacts, but they would still be substantial.

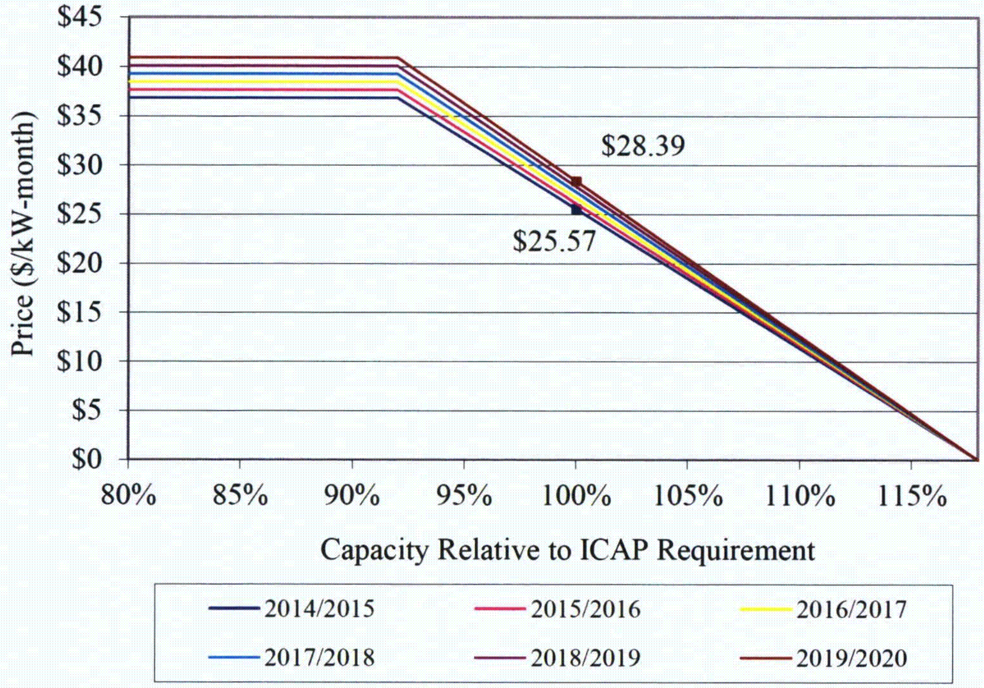
Figure B-2. NYCA Demand Curves



Note: Dollar values are in nominal dollars.
Source: NYISO (2013a, p. 35) for 2014/2015, 2015/2016, and 2016/2017;
NERA for 2017/2018, 2018/2019, and 2019/2020 based on linear extrapolation of the max clearing price

Figure B-3 shows estimated demand curves for NYC. Note that the NYC demand curves fall to zero at an 18 percent excess.

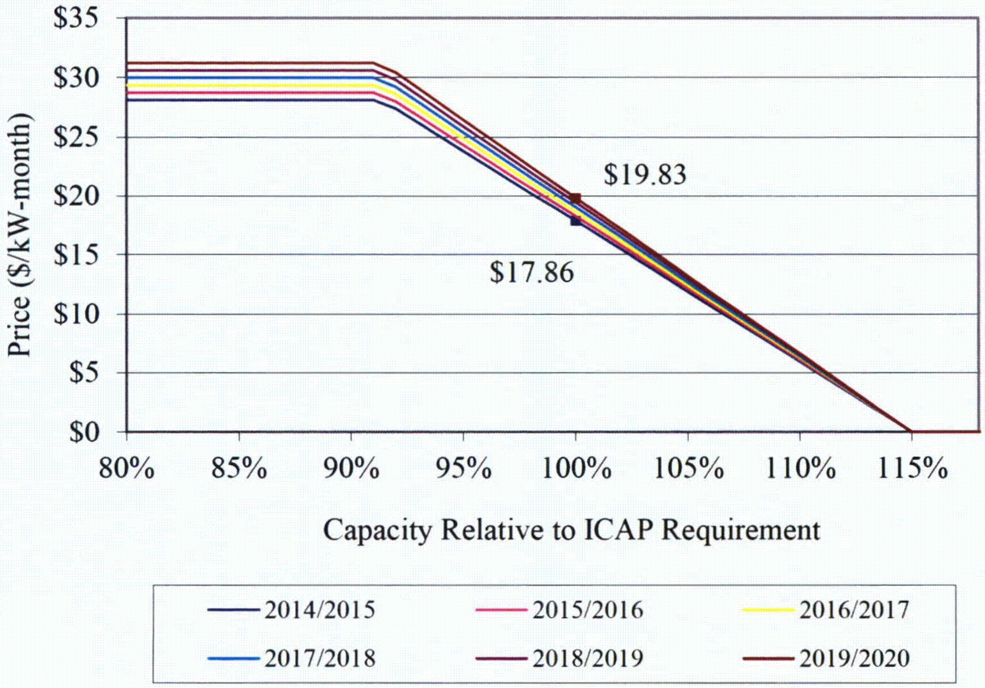
Figure B-3. NYC Demand Curves



Note: Dollar values are in nominal dollars.
Source: NYISO (2013a, p. 35) for 2014/2015, 2015/2016, and 2016/2017;
NERA for 2017/2018, 2018/2019, and 2019/2020 based on linear extrapolation of the max clearing price

Figure B-4 shows estimated demand curves for LHV. Note that the LHV demand curves fall to zero at 15 percent excess.

Figure B-4. LHV Demand Curves



Note: Dollar values are in nominal dollars.
Source: NYISO (2013a, p. 35) for 2014/2015, 2015/2016, and 2016/2017;
NERA for 2017/2018, 2018/2019, and 2019/2020 based on linear extrapolation of the max clearing price

2. Peak Load and ICAP Requirements

NYISO's 2013 Gold Book provides projected coincident peak demand (taking into account energy efficiency measures) in NYCA from 2015 to 2019. Table B-2 shows these demand projections. In addition, we assumed that Con Edison would implement an additional 185 MW of energy efficiency program in NYC (lowering demand in LHV and NYCA as well) as part of the Retirement Contingency Plan (RCP) (PSC 2013). Table B-2 shows the adjusted NYCA peak demand with the additional energy efficiency and the calculated ICAP requirement (118 percent of peak demand).

Table B-2. NYCA Peak Demand and ICAP Requirements (MW)

	Initial Peak Demand	RCP Energy Efficiency	Adjusted Peak Demand	ICAP Requirement
2015	34,138	-185	33,953	39,725
2016	34,556	-185	34,371	40,214
2017	34,818	-185	34,633	40,521
2018	35,103	-185	34,918	40,854
2019	35,415	-185	35,230	41,219

Note: ICAP requirements are based on an 18 percent reserve margin (the current level).
Source: NYISO (2013b, p. 8) and NERA calculations as explained in text

Table B-3 shows initial NYC demand projections from the 2013 Gold Book, the assumed Con Edison RCP additional energy efficiency, and adjusted peak demand. It also shows the ICAP requirement for the base scenario (86 percent of adjusted peak demand). As noted above, we assume that IPEC unavailability would lead NYSRC to raise the NYC ICAP requirement by 500 MW because IPEC's transmission support services would no longer be available for moving power into NYC from the north. The rightmost column of Table B-3 shows the resulting ICAP requirement for the IPEC not available scenario.

Table B-3. NYC Peak Demand and ICAP Requirements (MW)

	Initial Peak Demand	RCP Energy Efficiency	Adjusted Peak Demand	ICAP Requirement Base Scenario	IPEC Ret Adjustment	ICAP Requirement IPEC Ret Scenario
2015	11,832	-185	11,647	10,016	500	10,516
2016	12,006	-185	11,821	10,166	500	10,666
2017	12,137	-185	11,952	10,279	500	10,779
2018	12,266	-185	12,081	10,390	500	10,890
2019	12,419	-185	12,234	10,521	500	11,021

Note: ICAP base scenario requirements are based on an 86 percent local requirement (the current level).
Source: NYISO (2013b, p. 9) and NERA calculations of ICAP requirements

Table B-4 shows LHV demand projections and ICAP requirements based on an assumed continuation of the 88 percent local requirement. Note that the 2013 Gold Book does not provide projections for total LHV peak demand. Instead, the 2013 Gold Book provides projections for coincident peak demand (in all zones at the same time) and non-coincident peak demand (in each zone potentially at different times). To estimate total LHV peak demand, we increased coincident peak demand for Zones G through J by one-half of the difference between coincident and non-coincident peak demand for Zones G through I. In addition, we assumed that Con Edison's transmission projects as part of the RCP would lower LHV ICAP requirements by 600 MW (PSC 2013, p. 6). The adjusted LHV ICAP requirements apply for both the base scenario and IPEC not available scenario.

Table B-4. LHV Peak Demand and ICAP Requirements (MW)

	Initial Peak Demand	RCP Energy Efficiency	Adjusted Peak Demand	Initial ICAP Requirement	RCP Adjustment	Adjusted ICAP Requirement
2015	16,331	-185	16,146	13,771	-600	13,171
2016	16,565	-185	16,380	13,977	-600	13,377
2017	16,740	-185	16,555	14,131	-600	13,531
2018	16,913	-185	16,728	14,283	-600	13,683
2019	17,110	-185	16,925	14,457	-600	13,857

Note: Initial ICAP requirements are based on an 88 percent local requirement (the current level).
Source: NYISO (2013b, p. 9) and NERA calculations as explained in text

1. IPEC Capacities

Table B-5 shows summer and winter capacities for the IPEC units from the 2013 Gold Book.

Table B-5. IPEC Capacities (MW)

	Summer	Winter
Indian Point 2	1,024.5	1,031.3
Indian Point 3	1,044.2	1,044.3

Source: NYISO (2013b, p. 30)

2. Capacity Supply

The 2013 Gold Book (NYISO 2013b, pp. 66-67) provides summer and winter capacity supply for NYCA for 2013 and future years (including 2015 through 2019). As noted above, capacity supply includes generation units as well as SCRs and external resources. Table B-6 shows projected capacity supply for NYCA from the 2013 Gold Book and shows percentages relative to the NYCA ICAP requirements (shown above in Table B-2). Note that for the base scenario, NYCA capacity supply is above the ICAP requirement for all years for both summer and winter. If IPEC is not available, however, NYCA capacity supply decreases based on IPEC's capacity. In this scenario, NYCA capacity supply is below the ICAP requirement for all years for summer and for 2017-2019 for winter. Thus, modifications are necessary to avoid violating the NYCA ICAP requirement if IPEC is not available, as discussed below.

Table B-6. Initial NYCA Capacity Supply (MW) from Percentage of ICAP Requirement

	Base Scenario				IPEC Not Available			
	Capacity Supply (MW)		% of ICAP Requirement		Capacity Supply (MW)		% of ICAP Requirement	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2015	41,620	42,439	104.8%	106.8%	39,551	40,363	99.6%	101.6%
2016	41,620	42,439	103.5%	105.5%	39,551	40,363	98.4%	100.4%
2017	41,620	42,439	102.7%	104.7%	39,551	40,363	97.6%	99.6%
2018	41,620	42,439	101.9%	103.9%	39,551	40,363	96.8%	98.8%
2019	41,620	42,439	101.0%	103.0%	39,551	40,363	96.0%	97.9%

Source: NYISO (2013b) and NERA calculations as explained in text

Table B-7 shows projected capacity supply for NYC based on information in the 2013 Gold Book and excesses supply relative to the NYC ICAP requirements above in Table B-3. Note that for the base scenario, the table indicates that NYC capacity supply would violate the ICAP requirement in 2017-2019 for summer. This creates the need for modifications to NYC for the base scenario, as discussed below. Moreover, since we assume that the ICAP requirement for NYC would increase by 500 MW if IPEC were not available, the percentages are lower in this other scenario. Indeed, NYC would violate the ICAP requirement in all years 2015-2019 for summer and in 2019 for winter. Thus, additional modifications are necessary to maintain the ICAP requirement for NYC if IPEC were not available, as discussed below.

Table B-7. Initial NYC Capacity Supply (MW) and Percentage of ICAP Requirement

	Base Scenario				IPEC Not Available			
	Capacity Supply (MW)		% of ICAP Requirement		Capacity Supply (MW)		% of ICAP Requirement	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2015	10,193	10,927	101.8%	109.1%	10,193	10,927	96.9%	103.9%
2016	10,193	10,927	100.3%	107.5%	10,193	10,927	95.6%	102.4%
2017	10,193	10,927	99.2%	106.3%	10,193	10,927	94.6%	101.4%
2018	10,193	10,927	98.1%	105.2%	10,193	10,927	93.6%	100.3%
2019	10,193	10,927	96.9%	103.9%	10,193	10,927	92.5%	99.1%

Source: NYISO (2013b) and NERA calculations as explained in text

Table B-8 shows projected capacity supply for LHV based on information in the 2013 Gold Book and excesses relative to the LHV ICAP requirements above in Table B-4. Note that in the base scenario, LHV would satisfy the ICAP requirements for all years 2015-2019 for both summer and winter. Since LHV loses IPEC's capacity if IPEC were not available, however, it would violate the ICAP requirement if IPEC were not available in all years for summer and in 2016-2019 for winter. Thus, modifications are necessary to avoid violating the LHV ICAP requirements if IPEC were not available, as discussed below.

Table B-8. Initial LHV Capacity Supply (MW) and Percentage of ICAP Requirement

	Base				IPEC Not Available			
	Capacity Supply (MW)		% of ICAP Requirement		Capacity Supply (MW)		% of ICAP Requirement	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2015	14,536	15,243	110.4%	115.7%	12,467	13,168	94.7%	100.0%
2016	14,536	15,243	108.7%	114.0%	12,467	13,168	93.2%	98.4%
2017	14,536	15,243	107.4%	112.7%	12,467	13,168	92.1%	97.3%
2018	14,536	15,243	106.2%	111.4%	12,467	13,168	91.1%	96.2%
2019	14,536	15,243	104.9%	110.0%	12,467	13,168	90.0%	95.0%

Source: NYISO (2013b) and NERA calculations as explained in text

D. Modifications to Avoid Violations of ICAP Requirements

This section describes our modifications to capacity supply and peak demand to avoid violating ICAP requirements in any locality in any time period. The modifications were also entered into PROMOD for modeling energy prices, emissions, and natural gas consumption, as described in the Appendix D.

1. Generation Unit Reactivations

As noted above, violation of ICAP requirements in the base scenario occur only in NYC for summer in most years of the analysis period. We address the NYC deficiency by assuming that in the base scenario, 220 MW of mothballed natural gas- and oil-fired capacity at the Astoria plant would be reactivated or continue operating through 2015-2017, and an additional 380 MW representing Astoria 4, for a total of 600 MW at the Astoria plant, would be activated for 2018-2019. Note that the reactivations occur slightly before our calculations indicate a deficiency for summer. This seems reasonable given the higher capacity prices in 2015 and subsequent years relative to recent historical years when Astoria's operator decided to mothball units (see Table B-18 near the end of this appendix). For our base scenario, we also reactivate 321 MW at the Bowline plant in LHV, which has suffered damage and is expected to return to full capacity by 2015.

The calculations above indicate that all three localities would have deficiencies relative to their ICAP requirements if IPEC were not available. For this scenario, we pulled forward the reactivation of the full 600 MW of Astoria (NRG and USPG) capacity to 2015 and continued it throughout the analysis period.

2. Generation Unit Additions

As explained in Appendix A, the economic viability of the CPV Valley plant relies on a variety of assumptions so in order to make our system model conservative, we include the unit for purposes of this report only. We project that the soonest the unit would become available to supply capacity to the market is 2018 and fills the need for generation in both the LHV and NYCA zones.

3. External Resources

As noted above, external resources contribute to capacity supply for each locality. We do not adjust external resources for the base scenario. If IPEC were not available, we assume that external resources for NYC (hence also LHV) would increase from 300 MW (base scenario) to 315 MW. This additional capacity for power imports could presumably come from the Hudson Transmission Partners (HTP) line, assuming PJM requirements were met.

4. Emergency Demand Response

The modifications described above still lead to some deficiencies in NYC for summer if IPEC were not available. To allow NYC to meet its ICAP requirements in this scenario, we assume 82 MW of emergency demand response programs in 2018 and 214 MW in 2019.

5. Summary of Final Capacity Supply Relative to ICAP Requirement

The following tables summarize capacity supply relative to ICAP requirements for each locality with the modifications described above to avoid ICAP violations (i.e., stay above 100 percent). Table B-9 shows the estimates after modifications for NYCA.

Table B-9. Final NYCA Capacity Supply (MW) from Percentage of ICAP Requirement

	Base Scenario				IPEC Not Available			
	Capacity Supply (MW)		% of ICAP Requirement		Capacity Supply (MW)		% of ICAP Requirement	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2015	42,161.1	42,882.5	106.1%	107.9%	40,472.4	41,186.9	101.9%	103.7%
2016	42,161.1	42,882.5	104.8%	106.6%	40,472.4	41,186.9	100.6%	102.4%
2017	42,161.1	42,882.5	104.0%	105.8%	40,472.4	41,186.9	100.2%	101.6%
2018	42,541.1	43,262.5	104.1%	105.9%	41,149.4	41,863.9	100.9%	102.5%
2019	42,541.1	43,262.5	103.2%	105.0%	41,149.4	41,863.9	100.4%	101.6%

Source: NERA calculations as explained in text

Table B-10 shows the estimates after modifications for NYC.

Table B-10. Final NYC Capacity Supply (MW) and Percentage of ICAP Requirement

	Base				Indian Point Retirement			
	Capacity Supply (MW)		% of ICAP Requirement		Capacity Supply (MW)		% of ICAP Requirement	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2015	10,412.5	11,147.3	104.0%	111.3%	10,807.5	11,542.3	102.8%	109.8%
2016	10,412.5	11,147.3	102.4%	109.7%	10,807.5	11,542.3	101.3%	108.2%
2017	10,412.5	11,147.3	101.3%	108.5%	10,807.5	11,542.3	100.3%	107.1%
2018	10,792.5	11,527.3	103.9%	110.9%	10,807.5	11,542.3	100.0%	106.0%
2019	10,792.5	11,527.3	102.6%	109.6%	10,807.5	11,542.3	100.0%	104.7%

Source: NERA calculations as explained in text

Table B-11 shows the estimates after modifications for LHV.

Table B-11. Final LHV Capacity Supply (MW) and Percentage of ICAP Requirement

	Base				IPEC Not Available			
	Capacity Supply (MW)		% of ICAP Requirement		Capacity Supply (MW)		% of ICAP Requirement	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2015	15,076.8	15,784.5	114.5%	119.8%	13,403.1	14,103.9	101.8%	107.1%
2016	15,076.8	15,784.5	112.7%	118.0%	13,403.1	14,103.9	100.2%	105.4%
2017	15,076.8	15,784.5	111.4%	116.7%	13,403.1	14,103.9	100.0%	104.2%
2018	15,456.8	16,164.5	113.0%	118.1%	14,080.1	14,780.9	103.5%	108.0%
2019	15,456.8	16,164.5	111.5%	116.7%	14,080.1	14,780.9	103.2%	106.7%

Source: NERA calculations as explained in text

E. Capacity Price Impacts

Based on the three tables above with capacity supply as percentages of ICAP requirements, we are able to develop projections of capacity prices for the base scenario and if IPEC were not available using the demand curves. Table B-12 shows estimated capacity prices in NYCA in summer months.

Table B-12. NYCA Capacity Price Increases (nominal $/kW-month): Summer

		IPEC Not Available		
	Base	Price	Increase	% Increase
2015	$4.42	$7.61	$3.20	72%
2016	$5.51	$8.74	$3.23	59%
2017	$6.24	$9.27	$3.02	48%
2018	$6.31	$8.88	$2.57	41%
2019	$7.19	$9.53	$2.34	32%

Source: NERA calculations as explained in text

Table B-13 shows estimated capacity prices in NYCA in winter months.

Table B-13. NYCA Capacity Price Increases (nominal $/kW-month): Winter

		IPEC Not Available		
	Base	Price	Increase	% Increase
2015	$3.05	$6.26	$3.21	105%
2016	$4.13	$7.37	$3.24	79%
2017	$4.85	$8.13	$3.29	68%
2018	$4.89	$7.64	$2.74	56%
2019	$5.76	$8.53	$2.77	48%

Source: NERA calculations as explained in text

Table B-14 shows estimated capacity prices in NYC in summer months.

Table B-14. NYC Capacity Price Increases (nominal $/kW-month): Summer

		IPEC Not Available		
	Base	Price	Increase	% Increase
2015	$20.39	$22.11	$1.72	8%
2016	$23.10	$24.73	$1.63	7%
2017	$25.29	$26.86	$1.57	6%
2018	$21.83	$27.83	$5.99	27%
2019	$24.33	$28.39	$4.07	17%

Source: NERA calculations as explained in text

Table B-15 shows estimated capacity prices in NYC in winter months.

Table B-15. NYC Capacity Price Increases (nominal $/kW-month): Winter

		IPEC Not Available		
	Base	Price	Increase	% Increase
2015	$9.74	$11.97	$2.23	23%
2016	$12.38	$14.51	$2.13	17%
2017	$14.46	$16.53	$2.07	14%
2018	$10.90	$18.56	$7.66	70%
2019	$13.31	$20.94	$7.63	57%

Source: NERA calculations as explained in text

Table B-16 shows estimated capacity prices in LHV in summer months. Shading indicates that LHV prices would be bound below in the base scenario by NYCA prices.

Table B-16. LHV Capacity Price Increases (nominal $/kW-month): Summer

		IPEC Not Available		
	Base	Price	Increase	% Increase
2015	$4.42	$16.10	$11.69	265%
2016	$5.51	$18.41	$12.90	234%
2017	$6.24	$19.04	$12.80	205%
2018	$6.31	$14.88	$8.57	136%
2019	$7.19	$15.60	$8.41	117%

Note: Shading indicates that LHV prices would be bound below by NYCA prices.
Source: NERA calculations as explained in text

Table B-17 shows estimated capacity prices in LHV in winter months. Shading indicates that LHV prices would be bound below in the base scenario in all years and in 2015 if IPEC were not available.

Table B-17. LHV Capacity Price Increases (nominal $/kW-month): Winter

		IPEC Not Available		
	Base	Price	Increase	% Increase
2015	$3.05	$9.63	$6.58	216%
2016	$4.13	$11.90	$7.77	188%
2017	$4.85	$13.67	$8.82	182%
2018	$4.89	$9.05	$4.15	85%
2019	$5.76	$11.02	$5.26	91%

Note: Shading indicates that LHV prices would be bound below by NYCA prices.
Source: NERA calculations as explained in text

Table B-18 shows recent historical capacity prices for the localities (except LHV because it will take effect in May 2014) and our base case projections. Note that base case projections are higher than recent historical prices. This provides an incentive for currently mothballed units to reactivate in the future in the base scenario, as discussed above.

Table B-18. Capacity Price Comparison: Historical and Projected (nominal $/kW-month)

	Summer			Winter (a)			Annual Average		
	NYCA	NYC	LHV	NYCA	NYC	LHV	NYCA	NYC	LHV
Historical									
2010	$1.72	$12.99	(b)	$0.35	$3.73	(b)	$1.04	$8.36	(b)
2011	$0.29	$8.34	(b)	$0.17	$4.05	(b)	$0.23	$6.19	(b)
2012	$2.27	$11.88	(b)	$1.99	$4.65	(b)	$2.13	$8.27	(b)
2013	$5.80	$16.07	(b)	$2.58	$7.54	(b)	$4.19	$11.80	(b)
Projected									
2014	(c)	(c)	(c)	(c)	(c)	(c)	(c)	(c)	(c)
2015	$4.42	$20.39	$4.42 (d)	$3.05	$9.74	$3.05 (d)	$3.73	$15.06	$3.73
2016	$5.51	$23.10	$5.51 (d)	$4.13	$12.38	$4.13 (d)	$4.82	$17.74	$4.82
2017	$6.24	$25.29	$6.24 (d)	$4.85	$14.46	$4.85 (d)	$5.55	$19.88	$5.55
2018	$6.31	$21.83	$6.31 (d)	$4.89	$10.90	$4.89 (d)	$5.60	$16.37	$5.60
2019	$7.19	$24.33	$7.19 (d)	$5.76	$13.31	$5.76 (d)	$6.47	$18.82	$6.47

Notes:

(a) Winter extends from November and December of row's year through April of the following year.
(b) LHV capacity locality takes effect in Summer 2014 (no historical data).
(c) No projections developed for 2014.
(d) LHV price bounded below by NYCA price.

Sources:

Historical prices 2010 through Summer 2013: Average of monthly spot auction results (NYISO website)
Historical prices Winter 2013-2014: Strip auction results in November 2013 (NYISO website)
Projected prices: NERA calculations

F. Capacity Payments

Table B-19 shows the total value of capacity payment increases in New York State (summing all localities except LI) for the base scenario and if IPEC were not available. The increase in annual capacity payments would range from $1.2 billion per year to almost $1.6 billion per year. Over the near-term period 2015-2019, the total increase in capacity payments would be almost $7 billion.

Table B-19. NYS Capacity Payments (millions of 2012$)

		IPEC Not Available		
	Base	Payments	Increase	% Increase
2015	$2,941	$4,225	$1,285	44%
2016	$3,525	$4,803	$1,278	36%
2017	$3,920	$5,152	$1,232	31%
2018	$3,522	$5,101	$1,579	45%
2019	$3,988	$5,406	$1,418	36%

Source: NERA calculations as explained in text

G. Implications of Brattle (2013) Demand Curve Parameters

As noted above, Brattle (2013) presents alternative Demand Curve parameters. As a sensitivity case, Table B-20 shows estimated increases in annual capacity payments for New York State if the parameters from Brattle (2013) were used for the analyses outlined above. As shown in the table, increases in annual capacity payments if IPEC were not available under the Brattle (2013) demand curve parameters would range from $999 million per year to $1,244 million per year over the period 2015-2019. The total increase in capacity payments would be about $5.4 billion.

Table B-20. NYS Capacity Payments using Brattle (2013) Demand Curve Parameters (millions of 2012$)

		IPEC Not Available		
	Base	Payments	Increase	% Increase
2015	$2,438	$3,514	$1,076	44%
2016	$2,945	$3,996	$1,051	36%
2017	$3,280	$4,280	$999	30%
2018	$2,988	$4,232	$1,244	42%
2019	$3,384	$4,482	$1,098	32%

Source: NERA calculations as explained in text

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Appendix C. Overview of PROMOD IV[21]

PROMOD IV, the current version of PROMOD, is a state-of-the-art electricity market model developed and leased by Ventyx, Inc. PROMOD simulates regional electricity markets on an hourly basis in order to project production costs and market-clearing prices for periods ranging from a week to thirty years. PROMOD IV recognized in the industry for its flexibility and breadth of technical capability, incorporating extensive details in transmission constraints, generation analysis, and unit operating conditions.

The Hourly Monte Carlo Dispatch features advanced unit commitment and dispatch procedures in an hourly chronological dispatch, with a unique Monte Carlo treatment of generating unit forced outages. The method performs a deterministic commitment and dispatch on an hourly basis. This Monte Carlo treatment of generating unit forced outages has been designed to mitigate problems inherent in other Monte Carlo approaches to modeling forced outages. PROMOD also can perform Monte Carlo uncertainty analysis of demand or other electricity market parameters.

The unit commitment logic is based on Ventyx's detailed marginal scheduler logic that realistically models generator constraints for minimum runtime and minimum downtime, along with start-up costs, capacity bids, and energy bids. This process starts with an initial unit commitment loading order for each modeled week, and then performs an iterative improvement of the unit commitment schedule for each day of each week. Checking for violations of minimum runtime and minimum downtime constraints on each unit, the logic looks for alternative commitment decisions that improve the economic performance of the system. The possible actions it considers include running a unit more or fewer hours, in accordance with its runtime and downtime constraints; keeping a cycling unit on at minimum overnight; and replacing a cycling unit with a higher cost unit that may better match the system requirement. Once the unit commitment schedule has been determined, the economic dispatch is performed by loading incremental unit segments in bid order, subject to spinning and quick-start reserve constraints and other operational constraints.

The impacts of the electric grid are incorporated via transmission interface limits, loss factors and economic limitations, or tariffs. Transmission interface limits include dynamic constraints to the power that can flow between sub-regions, leading to differences in market-clearing prices between sub-regions. Tariffs can be used to model actual transmission tariffs in place, or to simulate market inefficiencies and immaturity.

PROMOD is continually being enhanced to model current and future market situations. The PROMOD Transmission Analysis Module has been used to analyze independent system operators and less formal systems to forecast energy prices, financial transmission rights, transmission congestion rents, flowgate values, new generation versus transmission upgrade decisions, and volatility of energy prices and the key underlying drivers of energy prices.

[21] This appendix is based on a description of PROMOD IV by Ventyx, Inc.

Appendix D. PROMOD Modeling Inputs

This appendix describes the inputs to the PROMOD IV model we use for both the base case scenario and scenario without IPEC. The PROMOD modeling region encompasses New York State, PJM Mid-Atlantic (consisting of New Jersey, Delaware, eastern Pennsylvania, eastern Maryland, the portion of Virginia on the Delmarva peninsula, and DC), New England, Ontario, and Quebec. We modeled individual generators and demand zones in each of these regions except Quebec, which we modeled with fixed electricity prices.

PROMOD includes built-in modeling inputs for generation units, demand, fuel prices, and other key information for modeling electricity markets. For our version of the model, Ventyx provides built-in modeling inputs that reflect market conditions and expectations as of July 2013. We reviewed and verified these built-in modeling inputs based on information from the ISOs (including generation unit additions and retirements and demand projections). We updated the PROMOD modeling inputs with up-to-date information, including recent developments related to generating units and recent fuel price projections. In addition, we adjusted inputs for both the base scenario and IPEC Not Available scenario for consistency with the reliability and capacity market analyses (see Appendices A and B). As discussed above, capacity market considerations impose constraints and requirements that influence wholesale electric energy market conditions.

This appendix provides information on the following specific inputs:

- Generation Unit Additions and Uprates;
- Generation Unit Retirements and Mothballs;
- Special Case Resources (Demand Response);
- Electricity Demand;
- Transmission;
- Fuel Prices; and
- Emission Allowance Prices

The appendix combines information from the built-in data base accompanying the PROMOD model, adjustments and updates based on recent developments, adjustments for consistency with the capacity market analyses, and information on the assumptions for changes that would occur if IPEC were not available.

A. Generation Unit Additions and Uprates

Due to the tentative nature of projected capacity changes in the electricity market, we carefully reviewed and modified the built-in modeling assumptions to reflect the most up-to-date information regarding generation unit additions and reratings (i.e., changes to capacity at existing units). We developed these inputs using information on recent and future additions and reratings from the New York Independent System Operator (NYISO) and electricity system operators in the other regions. We entered these inputs into PROMOD as adjustments to the Eastern Interconnection generator database that comes with PROMOD.

1. New York State

a. General Review and Updates

Additions and reratings in New York State are based on those that NYISO used in its *2012 Reliability Needs Assessment* (*RNA*) and NYISO's 2013 *Load and Capacity* report ("Gold Book") (NYISO 2012a, 2013a). These additions and reratings are a subset of the many projects that power companies have proposed to NYISO, which are published in the NYISO Interconnection Queue (NYISO 2013b) and the annual *Load and Capacity* report. NYISO selected projects for inclusion in its modeling for the *2012 RNA* based on rules related to project status and other assessments (NYISO 2012a, p. 14). In the 2013 *Load and Capacity* report, NYISO identifies the additions and reratings that have met base case inclusion rules in the NYISO Comprehensive Reliability Planning Process (CRPP) (NYISO 2013a, pp. 57-58). We include these same additions and reratings in our modeling.

Table D-1 identifies the New York State additions and reratings used in the modeling. Note that the table includes recent additions in 2012 as well as future additions and reratings.

Table D-1. NYS Additions and Reratings

Plant	Zone	Fuel	Capacity (MW)	Date
Bayonne Energy Center	J	Natural Gas	500	Jun-12
Marble River Wind Farm	D	Wind	83	Dec-12
Marble River II Wind Farm	D	Wind	132	Dec-12
Stony Creek Wind Farm	C	Wind	94	Mar-13

Source: NYISO (2013a, p. 57)

Reratings	Zone	Fuel	Incremental Capacity	Date
Stewarts Bridge Hydro	F	Hydro	3	May-13
Nanticoke Landfill	C	Renewable	1.6	Jun-13

Source: NYISO (2013a, p.58)

b. Base Case Changes in New York Based on Capacity Market Requirements

In addition to our base case modeling assumptions, we make adjustments to our generation capacity based on our reliability and capacity market analyses discussed in Appendices A and B. These assumptions are not included in the built-in PROMOD model and are based on NERA's expectation of likely responses to needs meeting the ICAP requirements in New York State.

With regard specifically to additions and rerates, we will activate an additional 321 MW of generation at the Bowline generating station at the start of our modeling period in 2015.

c. Changes in New York if IPEC Were Not Available

As discussed in Appendix A, we make the conservative assumption that CPV Valley would begin operation and supply a capacity of 677 MWs to the system in NYISO Zone G. We model the unit with a start date of January 1, 2018.

2. Base Scenario Changes in Other Regions

For electricity regions other than NYISO, we reviewed information regarding additions and reratings from each independent system operator (ISO). We included additions and reratings in our modeling if the ISO indicated that construction had commenced on the project. Thus, as with NYISO, the additions and reratings for other electricity regions that we included in our modeling are a subset of the many projects that have been proposed and entered into each ISO's interconnection queue.

Table D-2 shows the additions from the PJM interconnection queue (2013b) that we included in our modeling for PJM Mid-Atlantic.

Table D-2. PJM Mid-Atlantic Capacity Additions

Plant	Zone	Fuel	Capacity (MW)	Date
West Deptford	NJ	Natural Gas	650	Apr-14
Garrison	DE	Natural Gas	309	Apr-15
Howard M Down	NJ	Natural Gas	63	Apr-15
Newark Energy Center	NJ	Natural Gas	705	Jan-16

Source: PJM (2013b)

Table D-3 shows the additions from the ISO-NE interconnection queue (2013b) that we included in our modeling for New England.

Table D-3. ISO-NE Capacity Additions

Plant	Zone	Fuel	Capacity (MW)	Date
Comerford Unit #4	NH	Hydro	48	Mar-13
Plainfield Renewable Energy Project	CT	Renewable	38	Oct-13
Fair Haven Biomass	VT	Renewable	33	Mar-16

Source: ISO-NE (2013b)

Table D-4 lists the additions and reratings for Ontario as they are presented in the 18-Month Outlook and included in our model (IESO 2013).

Table D-4. IESO Capacity Additions and Reratings

Plant	Zone	Fuel	Capacity (MW)	Date
Bruce Unit 1	Bruce	Nuclear	750	Jul-12
Comber Wind	West	Wind	166	Jul-12
Bruce Unit 2	Bruce	Nuclear	750	Oct-12
Thunder Bay Condensing Turbine Project	Northwest	Biomass	40	Jan-13
Summerhaven Wind Energy Project	Southwest	Wind	125	Apr-13
Atikokan Biomass	Northwest	Biomass	205	Oct-13
Sir Adam Beck	Niagara	Hydro	30	Jan-14
South Kent Wind Project	West	Wind	270	Jan-14
East Lake St. Clair Wind	West	Wind	99	Jul-14
Erieau Wind	West	Wind	99	Jul-14

Source: IESO (2013, p. 8)

B. Generation Unit Retirements and Mothballs

Similar to additions and reratings, proposed retirements and mothballs are subject to varying schedules. We therefore update the built-in assumptions with the most current information available regarding retirements and mothballs through the ISO reports for each region and other supplemental publicly available information.

1. New York State

a. General Review and Updates

We based our generation unit retirements in New York State on recent and proposed retirements in the *2012 RNA* and the 2013 *Load and Capacity* report. Table D-5 identifies the New York State retirements used in the modeling. Note that the table includes recent retirements in 2012 as well as future retirements.

Table D-5. NYS Capacity Retirements

Plant	Zone	Date	MW
Far Rockaway ST 04	K	6/1/2012	110.6
Glenwood ST 04	K	6/1/2012	118.7
Glenwood ST 05	K	6/1/2012	122
Kensico Units 1-3	I	9/25/2012	3
Danskammer 1-6	G	1/3/2013	508
Montauk Units 2-4	K	5/4/2013	6
Niagara Biogen	A	5/9/2013	50
Total			**918.3**

Source: NYISO (2013a, p. 59)

Table D-6 identifies recently mothballed units as reported by the 2013 *Load and Capacity* report. These units have not been fully retired and may continue producing power in the future should the economic conditions change, most notably capacity prices. Repowering mothballed generation may be quicker and more cost effective than constructing new generation.

Table D-6. NYS Mothballed Units

Plant	Zone	Date	MW
Greenidge 4	C	3/18/2011	106.1
Westover 8	C	3/18/2011	83.8
Astoria 2	J	4/11/2012	177
Astoria 4	J	4/18/2012	375.6
Astoria GT 10	J	5/1/2012	24.9
Astoria GT 11	J	7/1/2012	23.6
Baldwinsville 2	A	7/3/2012	0.3
Dunkirk 3	A	9/10/2012	201.4
Dunkirk 4	A	9/10/2012	199.1
Dunkirk 1	A	9/10/2012	96.2
Dunkirk 2	A	6/1/2015	97.2
Total			**1385.2**

Source: NYISO (2013a, p. 59)

b. Base Scenario Adjustments Based on Capacity Market Analyses

In order to adhere to locational ICAP requirements in NYC and the Lower Hudson Valley, we reactivate mothballed generation at Astoria 2 in 2015 (USPG) and continue the operation of the GTs Astoria 10 and 11(NRG) reactivated in 2013 (NYISO 2011, NRG 2013).[22] To keep pace with growing energy demand, we reactivate an additional 380 MWs of mothballed generation at the Astoria 4 (USPG) plant in 2018 (NYISO 2012b).

These reactivations are necessary to keep base scenario capacity supply at least 100% of ICAP requirement and seem reasonable based on projected capacity prices being higher than the historical prices when these units were mothballed as shown in Appendix B.

c. IPEC Not Available Scenario Adjustments Based on Capacity Market Analyses

In order to fill the immediate void left should IPEC become unavailable, we pull the reactivation of Astoria 4 forward from 2018 in the base case to 2015.

2. Other Regions

For electricity regions other than NYISO, we reviewed information regarding retirements from each ISO. Table D-7 shows the retirements that we used in our modeling for PJM Mid-Atlantic.

[22] The Astoria 10 and 11 units were returned to service in Summer 2013 (NRG 2013).

Table D-7. PJM Mid-Atlantic Capacity Retirements

Plant	Zone	Fuel	Capacity (MW)	Date
Indian River 3	DPL	Coal	170	Dec-13
Burlington 9 GT	PSEG	FO2	184	Jun-14
Riverside 6	BGE	Natural Gas	118	Jun-14
Portland 1-2	MetEd	Coal	401	Jan-15
Shawville 1-4	PenElec	Coal	597	Apr-15
Titus 1-3	MetEd	Coal	243	Apr-15
Gilbert CT C1-4	JCPL	Natural Gas/FO2	98	May-15
Glen Gardner CTs	JCPL	Natural Gas	160	May-15
Kearny9	PSEG	Natural Gas	21	May-15
Werner CT C1-4	JCPL	FO2	212	May-15
Cedar 1-2	AE	Kerosene	66	May-15
Deepwater 1&6	AE	Natural Gas	158	May-15
Essex 12 (#121-124)	PSEG	Natural Gas	184	May-15
Middle Energy Center 1-3	AE	Kerosene	75	May-15
Missouri Ave CT B-D	AE	Kerosene	60	May-15
Bergen 3	PSEG	Natural Gas	21	Jun-15
Burlington 11 #111-114	PSEG	FO2	184	Jun-15
Burlington 8	PSEG	FO2	21	Jun-15
Edison 1-3 #11-34	PSEG	Natural Gas	504	Jun-15
Essex 10 #101-104	PSEG	Natural Gas	168	Jun-15
Essex 11 #111-114	PSEG	Natural Gas	184	Jun-15
Mercer 3	PSEG	FO2	115	Jun-15
National Park 1	PSEG	FO2	21	Jun-15
Sewaren 1-4	PSEG	Natural Gas	453	Jun-15
Sewaren 6	PSEG	FO2	111	Jun-15

Source: PJM (2013c)

Table D-8 shows the retirements that we used in our modeling for ISO-NE sourced from baseline PROMOD inputs and verified through NERA analysis.

Table D-8. ISO-NE Capacity Retirements

Plant	Zone	Fuel	Capacity (MW)	Date
Salem Harbor 1	NEMA/Boston	Coal	82	Jun-14
Salem Harbor 2	NEMA/Boston	Coal	80	Jun-14
Salem Harbor 3	NEMA/Boston	Coal	150	Jun-14
Salem Harbor 4	NEMA/Boston	Oil	436	Jun-14
AES Thames	CT	Coal	182	Jun-16
Kendal Steam	NEMA/Boston	Oil	53	Jun-16

Source: NERA analysis as explained in text.

Table D-9 shows the retirements we used in our modeling for Ontario sourced from original PROMOD inputs verified through NERA research and the IESO 18 Month Outlook (IESO 2013).

Table D-9. IESO Capacity Retirements

Plant	Zone	Fuel	Capacity (MW)	Date	Status
Atikokan:1	Northwest	Coal	211	Jan-13	Repower
Lambton:3	West	Coal	489	Dec-14	Retire
Lambton:4	West	Coal	502	Dec-14	Retire
Nanticoke:5	Southwest	Coal	490	Dec-14	Retire
Nanticoke:6	Southwest	Coal	490	Dec-14	Retire
Nanticoke:7	Southwest	Coal	508	Dec-14	Retire
Nanticoke:8	Southwest	Coal	490	Dec-14	Retire

Source: NERA analysis as explained in text and IESO (2013, p. 9)

C. Special Case Resources (Demand Response)

Special case resources (SCRs) are a form of demand response (i.e. reductions in demand). The companies that register as SCRs must curtail power usage by a predetermined quantity when requested to do so by the ISO, and they are compensated for their participation. PROMOD models demand response through proxy SCR generators.

1. New York State

a. General Review and Updates

We based our PROMOD SCR inputs for New York State on monthly reports of recent historical SCR quantities from NYISO (NYISO 2013c). We scaled these quantities to match the maximum SCR quantity (1,558 MW) that NYISO used in its *2013 Load and Capacity* report (NYISO 2013a, p. 22). We assumed that SCRs are available in each zone and future month in the same quantity that they were available in the corresponding zone and month during the twelve-month period between April 2012 and March 2013, with scaling for consistency with the *2013 Load and Capacity* report.

Table D-10 presents the New York State SCR quantities used in the modeling.

Table D-10. NYS Special Case Resources (MW)

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
A	202	202	204	204	267	280	282	286	293	293	198	202
B	30	30	29	29	80	90	90	91	89	89	27	30
C	55	55	54	54	97	100	104	108	113	113	54	55
D	374	374	374	374	249	250	362	362	357	357	374	374
E	11	10	11	11	31	32	33	34	34	34	9	11
F	38	38	37	37	104	105	105	107	104	104	39	38
G	21	21	20	20	46	52	52	56	56	56	20	21
H	4	4	4	5	7	8	8	8	8	8	5	4
I	7	7	7	7	30	31	32	33	33	26	7	6
J	205	202	211	215	296	309	336	338	363	350	199	202
K	33	33	33	33	102	103	109	109	108	108	32	32
Total	980	977	985	990	1,309	1,359	1,512	1,532	1,558	1,539	966	974

Source: NERA calculations based on NYISO (2013c) and NYISO (2013a p. 22)

b. Base Case Scenario Adjustments

Under baseline conditions, we do not make any changes to our SCR assumptions. Changes made to capacity are sufficient to meet 100 percent ICAP requirement in each of the capacity regions in the base case.

c. IPEC Not Available Scenario Adjustments Based on Capacity Market Analysis

In our scenario where IPEC capacity is not available, we make adjustments to our SCR assumptions, additional to adjustments made to firm capacity. In the NYC capacity region, we add 82 MWs of SCR capacity in 2018 and 214 MWs of SCR capacity in 2019. These adjustments are needed to help bring NYC in compliance with its ICAP requirement and are more likely to be available in the short term than additional firm capacity.

2. Other Regions

For electricity regions other than NYISO, we reviewed information regarding demand response from the ISOs.

PJM reports regional load management in its *2013 PJM Load Forecast Report* (2013). The PJM report lists special case resources as annual values that are constant after 2015. Table D-11 shows the SCR inputs that we used in the modeling for PJM Mid-Atlantic.

Table D-11. PJM Mid-Atlantic Special Case Resources (MW)

Generator	2015	2016	2017	2018	2019
PJM MidAtlantic - E	2,519	2,519	2,519	2,519	2,519
PJM MidAtlantic - East PA	1,451	1,451	1,451	1,451	1,451
PJM MidAtlantic - SW	1,938	1,938	1,938	1,938	1,938
PJM MidAtlantic - West PA	507	507	507	507	507
Total	6,415	6,415	6,415	6,415	6,415

Source: NERA calculations based on PJM (2013a, p57)

ISO-NE reports regional load management in its 2013 Capacity, Energy, Loads, and Transmission (CELT) report (2013a). We use the summer values for SCRs listed in the report. Table D-12 shows the SCR inputs that we used in the modeling for ISO-NE. Ontario does not provide information on SCRs.

Table D-12. ISO-NE Special Case Resources (MW)

Generator	2015	2016	2017	2018	2019
NE-East	1,313	974	1,057	1,135	1,207
NE-Maine	440	379	411	442	470
NE-SWCT	413	378	410	440	469
NE-WE	987	832	903	969	1,032
Total	3,153	2,563	2,781	2,986	3,178

Source: NERA calculations based on ISO-NE (2013a)

Ontario (IESO) reports available demand side resources in its 18-Month Outlook from June 2013 to November 2014 (IESO 2013). We use IESO's "Firm Projection" scenario as input for our model as it represents available demand resources that are certain over the outlook period. IESO assumes there will be 512 MW of firm demand side resources available in winter 2014, 502 MW in summer 2014 and 577 MW in winter 2015. We carry the winter 2015 value forward for the duration of the study period.

D. Electric Energy Demand

This section summarizes the assumptions on the electric energy demand over the modeling period.

1. New York State

a. General Review and Updates

We based our electricity demand projections for New York State on information in the 2013 *Load and Capacity* report. We used projections for non-coincident peak summer and winter demand in each zone (including the effects of energy efficiency and demand response programs). The non-coincident peak demand for the zones represents maximum demand for each zone individually for the particular season, rather than the collective maximum (when the total demand among all zones is at its highest). PROMOD uses non-coincident annual peak demand in each zone in each year of the modeling period. For most zones, the annual peak occurs in summer, but for Zone D (North), the annual peak often occurs in winter.

Table D-13 presents peak demands from the 2013 *Load and Capacity* report.

Table D-13. NYS Non-coincident Annual Peak Demand (MW)

Zone	2015	2016	2017	2018	2019
A	2,716	2,734	2,743	2,749	2,755
B	2,139	2,158	2,172	2,187	2,199
C	2,969	2,996	3,012	3,032	3,045
D	898	903	906	910	910
E	1,501	1,515	1,519	1,523	1,527
F	2,431	2,458	2,480	2,502	2,520
G	2,348	2,376	2,398	2,418	2,439
H	704	715	721	729	737
I	1,475	1,496	1,511	1,527	1,542
J	11,832	12,006	12,137	12,266	12,419
K	5,609	5,688	5,713	5,760	5,827

Note: Annual peak demand often occurs during winter in Zone D and during summer in all other zones.
Source: NERA calculations based on NYISO (2013a, p. 9)

b. Base Scenario Adjustments Based on Capacity Market Analyses

Based on recent development in the Con Edison contingency plan, we accept for the purposes of this analysis that the Con Edison demand reductions targets will be achieve and we adjust the NYC peak demand downward by 185 MWs to reflect the peak reduction estimate in Con Edison's energy efficiency program. This adjustment is included in our base case.

c. IPEC Not Available Scenario Adjustments Based on Capacity Market Analyses

Beyond the energy efficiency projected to shave NYC peak demand in the ConEd contingency plan, we do not model additional changes to peak demand projections in our IPEC Not Available scenario.

2. Other Regions

Our modeling incorporates the most recent available demand projections for PJM Mid-Atlantic (PJM 2013), New England (ISO New England 2013), and Ontario (IESO 2013).

Our electricity demand projections for PJM's Mid-Atlantic sub region are reported in the 2013 PJM Load Forecast Report. The demand projections are shown in Table D-14.

Table D-14. PJM Mid-Atlantic Non-coincident Annual Peak Demand (MW)

Zone	2015	2016	2017	2018	2019
AE	2,843	2,896	2,924	2,946	2,965
BGE	7,467	7,572	7,649	7,703	7,770
DPL	4,301	4,376	4,432	4,476	4,527
JCPL	6,503	6,637	6,704	6,737	6,795
METED	3,127	3,197	3,247	3,286	3,328
PECO	9,098	9,266	9,397	9,508	9,612
PENLC	3,100	3,183	3,243	3,285	3,338
PEPCO	7,015	7,073	7,123	7,167	7,215
PL	7,556	7,691	7,785	7,850	7,942
PS	10,861	11,002	11,083	11,138	11,208
RECO	429	434	436	437	439
UGI	203	206	209	210	211

Source: NERA calculations based on PJM (2013a, p. 42)

Our electricity demand projections for ISO-NE are reported in the 2013 CELT Report. The demand projections are shown in Table D-15.

Table D-15. ISO-NE Non-coincident Annual Peak Demand (MW)

Zone	2015	2016	2017	2018	2019
BHE	297	302	305	303	307
ME	897	910	924	934	943
SME	721	724	725	722	723
NH	2,190	2,243	2,268	2,293	2,314
VT	1,201	1,210	1,203	1,203	1,202
Boston	5,717	5,808	5,843	5,868	5,890
CMA/NEMA	1,687	1,716	1,725	1,734	1,745
WMA	2,122	2,160	2,174	2,184	2,195
SEMA	2,928	2,994	3,030	3,057	3,086
RI	2,460	2,510	2,536	2,554	2,569
CT	3,485	3,576	3,607	3,629	3,656
SWCT	2,368	2,429	2,454	2,470	2,486
NOR	1,217	1,248	1,258	1,268	1,274

Source: NERA calculations based on ISO-NE (2013a)

Our electricity demand projections for Ontario are reported in the 2013 18-Month Outlook. Since the IESO forecast is so short, there is only one full year of demand projections. We therefore keep demand steady beyond 2014 as shown in Table D-16.

Table D-16. IESO Non-coincident Annual Peak Demand (MW)

Zone	2015	2016	2017	2018	2019
Bruce	132	132	132	132	132
East	1,436	1,436	1,436	1,436	1,436
Essa	1,398	1,398	1,398	1,398	1,398
Niagara	773	773	773	773	773
NorthEast	1,747	1,747	1,747	1,747	1,747
NorthWest	586	586	586	586	586
Ottawa	1,897	1,897	1,897	1,897	1,897
SouthWest	4,592	4,592	4,592	4,592	4,592
Toronto	9,383	9,383	9,383	9,383	9,383
West	2,406	2,406	2,406	2,406	2,406

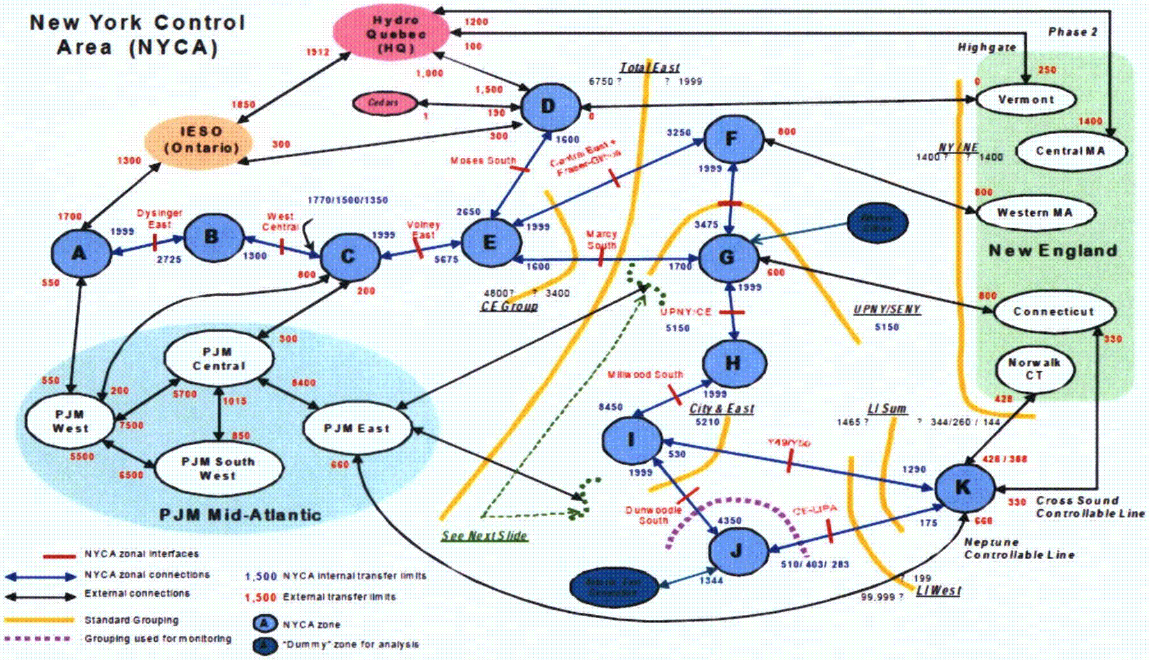
Source: IESO (2013)

E. Transmission

a. General Review and Updates

We based our transmission inputs on the transmission limits in the *2012 RNA*, using the figure below from the 2012 RNA for all transmission limits.

Transmission System Representation changes for 2013 IRM Study/2012 RNA - Summer Emergency Ratings (MW)



b. Base Scenario Adjustments

While we assumed that Con Ed's transmission projects (described in Chapter III) would reduce LHV's ICAP requirement by 600 MW, we do not explicitly model these in our electricity analysis. Much of the improvements proposed would take place within Zones G, H and I, which are grouped together as a single interface in our zonal model. Therefore, modeling these projects would not be feasible. We do not, however, expect that these projects will material affect energy prices in the region or energy price impacts from IPEC becoming unavailable (given that the transmission projects would be implemented in the base scenario as well).

c. IPEC Not Available Scenario Adjustments

We do not model any changes to our transmission system in the IPEC Not Available scenario.

F. Fuel Prices

Our modeling incorporates monthly price projections for natural gas, and oil. PROMOD calculates fuel prices for individual natural gas and oil generators based on wholesale price indices and individual price adders that primarily reflect transportation costs from pricing points such as Henry Hub and New York Harbor. PROMOD does not, however, index coal prices and instead models coal generators on a unit by unit basis. We used the default price adders in PROMOD and developed projections for the price indices based on recent settlements in the NYMEX futures market (NYMEX 2013). When these futures prices did not extend all the way to the end of our modeling horizon (2019), we applied growth rates from price projections in the Energy Information Administration's *Annual Energy Outlook ("AEO") 2013* version (EIA

2013). We show price projections in nominal dollars because PROMOD bases its production cost modeling on nominal dollars.

1. Natural Gas Prices

Table D-17 presents monthly projections for Henry Hub natural gas prices from NYMEX (2013). The NYMEX futures market includes trades for Henry Hub natural gas through 2019, so there was no need to use growth rates from *AEO 2013* for this price index.

Table D-17. Henry Hub Natural Gas Price Projections (nominal $/MMBtu)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015	$4.25	$4.22	$4.16	$3.97	$3.98	$4.01	$4.04	$4.05	$4.05	$4.07	$4.14	$4.31
2016	$4.39	$4.37	$4.30	$4.06	$4.07	$4.10	$4.13	$4.15	$4.15	$4.17	$4.24	$4.41
2017	$4.50	$4.48	$4.40	$4.16	$4.18	$4.20	$4.23	$4.25	$4.25	$4.28	$4.37	$4.55
2018	$4.64	$4.62	$4.55	$4.28	$4.29	$4.32	$4.35	$4.37	$4.37	$4.41	$4.52	$4.73
2019	$4.85	$4.83	$4.75	$4.50	$4.52	$4.55	$4.59	$4.61	$4.62	$4.66	$4.78	$4.99

Source: NYMEX (2013)

2. Oil Prices

Table D-18 presents monthly projections for New York Harbor #2 heating oil prices. Oil prices for individual generators in PROMOD use various price indices because they purchase various types of oil, including #2 heating oil and #6 residual fuel oil with various sulfur contents; the #2 heating oil price index is among the most widely used. NYMEX (2013) provides futures prices through January 2013. For later months, we applied growth rates from prices projections for #2 heating oil in *AEO 2013*.

Table D-18. New York Harbor #2 Heating Oil Price Projections (nominal $/MMBtu)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015	$21.09	$21.02	$20.92	$20.77	$20.59	$20.41	$20.33	$20.24	$20.16	$20.07	$19.99	$19.90
2016	$19.91	$19.87	$19.80	$19.70	$19.65	$19.62	$19.62	$19.60	$19.60	$19.59	$19.58	$19.57
2017	$19.56	$19.75	$19.69	$19.58	$19.53	$19.51	$19.51	$19.49	$19.48	$19.48	$19.47	$19.46
2018	$20.28	$20.47	$20.40	$20.30	$20.25	$20.22	$20.22	$20.20	$20.19	$20.19	$20.18	$20.17
2019	$21.04	$21.25	$21.18	$21.07	$21.01	$20.99	$20.98	$20.97	$20.96	$20.95	$20.95	$20.94

Note: NYMEX prices per gallon were converted to MMBtu using 1 gallon = 0.14 MMBtu.
Source: NERA calculations based on NYMEX (2013) and EIA (2013)

G. Emissions Allowance Prices

We use PROMOD built-in inputs for emission allowance prices, including SO_2, NO_x, and CO_2 prices. The built-in inputs include RGGI CO_2 prices but no national CO_2 prices. Table D-19 shows the emissions allowance prices from 2015 to 2019.

Table D-19. Emission Allowance Prices (nominal $/ton)

	2015	2016	2017	2018	2019
CAIR Annual NOx	$36.77	$37.69	$38.63	$39.60	$40.59
CAIR Seasonal NOx	$52.53	$53.84	$55.19	$56.57	$57.98
CAIR SO2	$0.00	$0.00	$0.00	$0.00	$0.00
RGGI CO2	$3.15	$3.23	$3.31	$3.39	$3.48

Source: PROMOD built-in inputs

H. Electricity Price Projections for Quebec

We modeled Quebec as an electricity market with fixed prices. The inputs are based on NYISO electricity price data for Quebec for each hour of 2012 (NYISO 2013d). We used the NYISO data to develop monthly peak and off-peak prices for Quebec in 2012. We assumed that these monthly peak and off-peak prices would be constant in real terms over the modeling period. Table D-20 displays the Quebec peak and off-peak prices used in the modeling.

Table D-20. Quebec Electricity Price Projections (nominal$/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015	$46.55	$35.12	$33.14	$30.13	$28.42	$30.31	$33.37	$30.06	$30.29	$32.23	$37.86	$32.32
2016	$47.40	$35.76	$33.74	$30.68	$28.93	$30.87	$33.97	$30.61	$30.84	$32.81	$38.54	$32.90
2017	$48.28	$36.42	$34.37	$31.25	$29.47	$31.44	$34.61	$31.18	$31.42	$33.42	$39.26	$33.52
2018	$49.20	$37.12	$35.03	$31.85	$30.03	$32.04	$35.27	$31.77	$32.02	$34.06	$40.01	$34.16
2019	$50.13	$37.81	$35.69	$32.45	$30.60	$32.64	$35.93	$32.37	$32.62	$34.70	$40.76	$34.80

Source: NERA calculations based on NYISO (2013d)

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Appendix D

Benefits and Costs of Cylindrical Wedgewire Screens and Cooling Towers at IPEC

(NERA)

Appendix D

December 2013

Benefits and Costs of Cylindrical Wedgewire Screens and Cooling Towers at IPEC

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Contents

Executive Summary

This report provides information on the costs and potential benefits of installing and operating either cylindrical wedgewire screens (CWWS) or closed-cycle cooling towers (Cooling Towers) at Indian Point Energy Center (IPEC) in the context of review under the State Environmental Quality Review Act (SEQRA). Cooling Towers have been proposed both by New York State Department of Environmental Conservation (NYSDEC) Staff and by Riverkeeper to reduce impingement and entrainment mortality (I&E) at the cooling water intake structures (CWIS) of IPEC. Entergy has proposed CWWS. Information on the costs and benefits of these alternatives is important in assessing social and economic considerations as called for in SEQRA.

The report provides descriptions of the methodologies and data used to conduct the analyses. Our analyses build on engineering and cost information on CWWS developed by ENERCON Services for CWWS and engineering and cost information on Cooling Towers developed by Tetra Tech on behalf of NYSDEC Staff (and critiques of that analysis developed by ENERCON) as well as on biological information developed by a team of expert biologists for the two technologies. We use well-established economic methods to develop social costs and social benefits estimates, drawing on guidelines developed by the U.S. Environmental Protection Agency (EPA), the U.S. Office of Management and Budget (OMB), and the economics literature (e.g., Boardman et al. 2011).

Benefit-cost analysis is a well-established methodology for providing information to decision makers faced with the task of determining whether a project should be undertaken and, if so, at what scale of activity. The approach involves systematic enumeration of costs and benefits that would accrue to members of society if a particular project were undertaken. The basic rationale for undertaking a social benefit-cost analysis of a particular decision—such as whether to require additional fish-protection technologies at IPEC—is to help put society's resources to their most valuable uses. In choosing among alternatives, the basic principle of benefit-cost analysis is to select the alternative that produces the greatest net benefits (i.e., benefits minus costs). It is possible that all alternatives produce net benefits that are negative, in other words, have costs greater than benefits (i.e., net costs). In that case, the highest value alternative is to "do nothing," which at least produces a net benefit of $0.

A. Overview of Alternatives

1. Cylindrical Wedgewire Screens

CWWS consist of specially designed screens made with wedge-shaped wires. With CWWS installed, the units at IPEC would withdraw water from the river through these structures. This modification to the CWIS would reduce I&E in three ways:

1. Through established mechanical forces, organisms are swept past the intake by the tidal flow in the Hudson River.
2. The large screen area reduces flow rates through the screens, thus facilitating behavioral avoidance and therefore I&E.

3. To a lesser degree, they provide a physical barrier preventing organisms larger than the screen spacing from being entrained.

ENERCON and the biological team investigated several alternative configurations for the screens that vary in the spacing of the slots and the velocity of water flowing through the screens (which is inversely proportional to the surface area of the screens). Entergy's proposed design includes a screen configuration with a slot size of 2 mm and through-screen flow velocity of 0.25 feet per second (ENERCON 2013a). ENERCON's analysis indicates that CWWS would take approximately six years to permit and build; based upon an assumption that the regulatory process could be completed by mid-2018, CWWS would be operational by 2024 (see ENERCON 2013a).

Our cost analyses for CWWS are based upon ENERCON (2013a). The benefit estimates for CWWS are based on theoretical estimates developed by ASA Analysis & Communication (ASAAC 2013). We measure biological benefits relative to the current configuration. We refer to benefits as theoretical biological benefits because biological analyses indicate that reducing I&E at IPEC in fact would not lead to any measurable increase in fish populations (Barnthouse et al 2008). ASAAC (2013) has developed theoretical calculations for the purposes of this analysis.[1]

2. Cooling Towers

The Cooling Towers alternatives proposed by NYSDEC Staff and Riverkeeper assume that IPEC would install closed-cycle cooling systems that would reduce the volume of water withdrawn from the Hudson River by approximately 97 percent if operated continuously over the year. ENERCON (2013b) has evaluated the Cooling Tower designs submitted by the consultants engaged by NYSDEC Staff and Riverkeeper and concluded that neither likely is feasible. For purposes of this analysis, however, we assume for sake of argument that the Cooling Towers alternative could be installed at IPEC. ENERCON (2013b) concludes that the design proposal from Tetra Tech on behalf of the NYSDEC Staff (Tetra Tech 2013) is more fully developed than the proposal from Riverkeeper (Powers 2013), although ENERCON (2013b) also concludes that the Tetra Tech design proposal is materially deficient.

For purposes of our evaluations, however, we rely upon the Tetra Tech report for information related to the cost and effectiveness of Cooling Towers, as well as for the timing of their installation. At one point Tetra Tech states that Cooling Towers would take between 7 and 9 years to install, although the Tetra Tech report provides other information on timing for individual phases that conflicts with this range. Taking the midpoint of the 7-9 year range and assuming the period would begin in mid-2018 (the same assumption as for CWWS), the Tetra Tech analysis thus would mean that Cooling Towers would be operational in mid-2026. As noted below, we also provide sensitivity analyses for different timing assumptions based upon information provided by Tetra Tech on ranges for the different phases of the project.

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[1] To avoid awkward phrasing, in some parts of the report we do not "theoretical" in our description of benefit metrics but all the estimates are understood to be theoretical because of the biological assessments noted in the text.

We supplement the Tetra Tech information on Cooling Towers where the information is incomplete. In particular, as discussed in Chapter 2 of TRC (2009), operation of the Cooling Towers would not comply with air emissions permitting requirements in some periods of the year, a factor that was not assessed by Tetra Tech. Thus, we presume that Cooling Towers would only be operated when operation would not violate air quality constraints. ENERCON (2010a) and ASAAC (2013) provide information on the implications of these constraints for operation of the Cooling Towers and their biological impacts and benefits. Appendix G to this report provides cost and benefit results assuming for sake of argument that air emissions permitting requirements do not constrain operation of the Cooling Towers.

B. Timing and Discounting

As noted above, based upon a presumed start date of mid-2018, our cost and benefit estimates presume that CWWS would begin operation in 2024 and Cooling Towers would begin operation in 2026. For Cooling Towers, we provide sensitivity cases based upon information provided by Tetra Tech on ranges for the individual elements of the project. Until the alternatives are operational, we assume that IPEC would continue to operate with its current CWIS configuration. Costs and benefits are projected until September 2033 for Unit 2, which would be the end of the 20-year license extension for which Entergy is applying at the NRC. Similarly, for Unit 3, costs and benefits are projected until December 2035, when the equivalent 20-year license extension would end.

We summarize the cumulative costs and benefits of the two alternatives during the period from 2018 to 2035 by calculating present values. For this calculation, we converted all annual costs and benefits by discounting them back to a common date (January 1, 2013) using annual real (inflation-adjusted) discount rates of 3 percent and 7 percent, based upon guidelines developed by the U.S. Office of Management and Budget (OMB) and the U.S. Environmental Protection Agency (EPA). We express all costs and benefits in constant 2012 dollars.

C. Benefit-Cost Results

Table S-1 summarizes the present values of costs, benefits, and net costs (i.e., costs minus benefits) of CWWS and Cooling Towers. Costs and benefits are calculated relative to the current configuration for both alternatives, although, as noted below, it is appropriate to evaluate the benefits and costs of the more-expensive Cooling Towers relative to those of the less-expensive CWWS alternative. (Because costs exceed benefits, for convenience we report net costs rather than negative net benefits.) Results are presented for the two discount rates (3 percent and 7 percent).

Table S-1. Present Values of Estimated Costs, Benefits, and Net Costs for CWWS and Cooling Towers ($millions)

Technology	Discount Rate 3%	7%
CWWS		
Costs	$169.5	$123.8
Benefits	$11.3	$6.1
Net Costs	$158.2	$117.7
Cooling Towers		
Costs	$1,056.6	$670.9
Benefits	$1.2	$0.6
Net Costs	$1,055.4	$670.2

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. Net costs may differ slightly from costs minus benefits because of rounding.
Source: NERA calculations as explained in text

Costs are substantially greater than benefits for both CWWS and Cooling Towers, but the net costs are considerably greater for Cooling Towers. For CWWS, the net costs range from about $118 million to about $158 million using the two discount rates. For Cooling Towers, the net costs range from about $670 million to about $1.1 billion using the two discount rates.

Because CWWS and Cooling Towers are alternative technologies that could be put in place, it is appropriate to consider the added benefits from the more-expensive Cooling Towers alternative in comparison to their added costs. Table S-2 shows the *differences* in costs and benefits between CWWS and Cooling Towers. The comparisons are quite dramatic. CWWS has much *smaller* costs than Cooling Towers, with the difference equal to either $547.0 million or about $887.1 million depending on the discount rate. In contrast, CWWS has substantially *larger* benefits than Cooling Towers, with the difference equal to either $5.5 million or about $10.1 million depending on the discount rate.

Table S-2. Comparisons of Costs and Benefits of CWWS and Cooling Towers ($million)

Technology	Discount Rate 3%	7%
Costs		
CWWS	$169.5	$123.8
Cooling Towers	$1,056.6	$670.9
Difference	+$887.1	+$547.0
Benefits		
CWWS	$11.3	$6.1
Cooling Towers	$1.2	$0.6
Difference	-$10.1	-$5.5

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. Differences may differ slightly from Cooling Tower values minus CWWS values because of rounding.
Source: NERA calculations as explained in text

Because CWWS yield *greater* benefits at substantially *smaller* costs than Cooling Towers, we conclude that Cooling Towers are "dominated" by the CWWS. Assuming there are no offsetting considerations, a rational decision maker would not choose a dominated alternative, i.e., an alternative with larger costs and smaller benefits. [2]

There are thus two principal conclusions from these results:

1. Costs exceed benefits for both CWWS and Cooling Towers using both discount rates; and

2. Cooling Towers has higher costs and smaller benefits than CWWS using both discount rates and thus can be considered "dominated" by CWWS.

D. Implications of Non-Quantified Costs and Benefits

We quantified the major cost and benefit categories, but we did not quantify some other potential cost and benefit categories. Following sound benefit-cost practice, we considered all non-quantified cost and benefit categories and evaluated whether their inclusion would be likely to affect the two basic conclusions, i.e., that both CWWS and Cooling Towers would result in large positive net costs and that Cooling Towers were dominated by CWWS.

We evaluated non-quantified costs and concluded that some (such as the costs related to additional greenhouse gas emissions) could be significant relative to quantified costs but that

[2] The economic term "dominant" or "dominate," most commonly used to describe strategies in game theory, conveys that a choice is superior to an alternative by every relevant criterion. Boardman et al. (2011, p. 469) explains its use in cost-benefit analysis: "One alternative can dominate another even if they have neither the same cost nor the same effectiveness, as long as it is superior on both dimensions. Clearly, dominated alternatives should not be selected."

quantifying them would not undermine our first basic conclusion and would reinforce our second basic conclusion. We evaluated non-quantified benefits and concluded that they would not be significant (individually or collectively) relative to quantified benefits, and thus quantifying them (if possible) would not change our two basic conclusions. Indeed, we identified several assumptions embedded in the benefit estimates that would likely lead to overstatements of potential benefits and thus reinforce our two basic conclusions.

From these considerations we conclude that the two major conclusions noted above—that both of the alternatives have costs that are significantly greater than the benefits and that Cooling Towers is dominated by CWWS—are robust with respect to assessments of non-quantified costs and benefits.

E. Implications of Uncertainties Regarding Costs and Benefits

EPA and OMB guidelines recommend that benefit-cost analyses include evaluations of the potential impacts of uncertainty on the results. These recommendations reflect the fact that benefit-cost estimates inevitably include uncertain elements. In addition, New York State guidelines for benefit-cost assessments state, "The presentation must also include enough discussion of the limitations, uncertainties and sensitivities of each part of the analysis to permit others to assess the results of the analysis (e.g., … if certain factual estimates, if off by a slight percentage, would drastically alter the conclusions reached)" (NY Governor's Office of Regulatory Reform 2008, p. 17).

We developed uncertainty analyses for cost and benefit categories, including construction costs, electricity prices, CWWS efficacy, and various parameters for converting the fishery harvest impacts into monetized benefits. All of the sensitivity cases resulted in the same conclusions as the basic analysis—i.e., that both CWWS and Cooling Towers would have significantly larger costs than benefits, and that Cooling Towers would be dominated by CWWS. We combined the uncertainty cases to develop two "extreme" cases—one in which all assumptions are "favorable" to the alternatives (i.e., costs are lower and benefits are higher) and one in which all assumptions are "unfavorable" to the alternatives (i.e., costs are higher and benefits are lower).

Table S-3 shows the results of the "all favorable" and "all unfavorable" sensitivity cases. Even with "all favorable" assumptions (leading to lower costs and higher benefits for each alternative than the base case assumptions), the two basic conclusions continue to hold: (1) costs are substantially greater than benefits for both CWWS and Cooling Towers; and (2) Cooling Towers are "dominated" by CWWS. Indeed, the Monte Carlo uncertainty analysis produced net costs for both alternatives for all draws, and Cooling Towers had lower benefits than CWWS for all draws in the Monte Carlo analysis.

Table S-3. Estimated Costs and Benefits with All Favorable Assumptions and All Unfavorable Assumptions

	Costs	Benefits	Net Costs	Change in Net Costs
r = 3%				
Base Case				
CWWS	$169.5	$11.3	$158.2	
Cooling Towers	$1,056.6	$1.2	$1,055.4	
Cooling Towers Incremental to CWWS	+$887.1	-$10.1	+$897.3	
All-Favorable				
CWWS	$153.9	$16.7	$137.2	-$21.0
Cooling Towers	$825.0	$1.9	$823.1	-$232.3
Cooling Towers Incremental to CWWS	+$671.1	-$14.8	+$685.9	-$211.3
All-Unfavorable				
CWWS	$202.5	$6.0	$196.5	$38.3
Cooling Towers	$1,494.3	$0.5	$1,493.8	$438.4
Cooling Towers Incremental to CWWS	+$1,291.8	-$5.5	+$1,297.3	+$400.1
r = 7%				
Base Case				
CWWS	$123.8	$6.1	$117.7	
Cooling Towers	$670.9	$0.6	$670.2	
Cooling Towers Incremental to CWWS	+$547.0	-$5.5	+$552.5	
All-Favorable				
CWWS	$112.2	$9.0	$103.2	-$14.6
Cooling Towers	$541.1	$1.0	$540.1	-$130.1
Cooling Towers Incremental to CWWS	+$429.0	-$7.9	+$436.9	-$115.6
All-Unfavorable				
CWWS	$148.1	$3.2	$144.9	$27.2
Cooling Towers	$815.6	$0.2	$815.4	$145.1
Cooling Towers Incremental to CWWS	+$667.5	-$3.0	+$670.5	+$118.0

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars.
"Favorable" assumptions are those that lead to lower costs and higher benefits for each alternative; "unfavorable" assumptions are those that lead to higher costs and lower benefits for each alternative

Source: NERA calculations as explained in text

F. Implications if Air Emission Permitting Conditions Are Ignored

As noted above, we estimated the potential costs and benefits of the Cooling Tower alternative under an assumption that local air quality issues were not relevant (i.e., assuming the Cooling Towers could operate continuously throughout the year). Table S-4 summarizes the results for CWWS and Cooling Towers.

Table S-4. Present Values of Estimated Costs, Benefits, and Net Costs for CWWS and Cooling Towers Ignoring Local Air Quality Requirements ($millions)

Alternative	Discount Rate r = 3%	Discount Rate r = 7%
CWWS		
Costs	$169.5	$123.8
Benefits	$11.3	$6.1
Net Costs	$158.2	$117.7
Cooling Towers		
Costs	$1,056.6	$670.9
Benefits	$10.0	$5.2
Net Costs	$1,046.6	$665.7

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. Net costs may differ slightly from costs minus benefits because of rounding.
Source: NERA calculations as explained in text

Table S-5 compares the incremental costs and benefits for CWWS (relative to the current configuration) and for Cooling Towers (relative to CWWS) under these same assumptions for Cooling Towers.

Table S-5. Present Value Costs and Benefits for CWWS and Cooling Towers Ignoring Local Air Quality Requirements ($millions)

Alternative	Discount Rate r = 3%	Discount Rate r = 7%
Costs		
CWWS	$169.5	$123.8
Cooling Towers	$1,056.6	$670.9
Difference	+$887.1	+$547.0
Benefits		
CWWS	$11.3	$6.1
Cooling Towers	$10.0	$5.2
Difference	-$1.3	-$0.9

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. Net costs may differ slightly from costs minus benefits because of rounding.
Source: NERA calculations as explained in text

As shown in the tables above, operating the Cooling Towers continuously throughout the year would produce larger benefits than if they were operated to comply with local air quality regulations (our base case), but the costs of Cooling Towers with continuous operation would still be much larger than the benefits. Moreover, even with the assumption of continuous operation, Cooling Towers would result in smaller benefits on a present value basis than CWWS. CWWS leads to larger benefits than Cooling Towers in this case because the annual benefits are similar for the two technologies and CWWS would be in operation sooner than Cooling Towers (and thus lead to greater cumulative benefits).

G. Overall Conclusions

Based on the analyses summarized above, we reach the following conclusions regarding the costs and benefits of CWWS and Cooling Towers.

- Neither CWWS nor Cooling Towers passes a social benefit-cost test, because their social costs are substantially greater than their potential social benefits.
- The appropriate benefit-cost comparison for Cooling Towers is to compare the additional costs and the additional benefits relative to those under the less expensive CWWS.
- Comparing added costs and added benefits indicates that Cooling Towers are dominated by CWWS, because Cooling Towers would have significantly higher costs than CWWS but significantly lower benefits.
- These conclusions do not change if one considers factors that have been excluded from the quantitative assessments. We reviewed the relevant categories of non-quantified costs and benefits and determined that including any of these categories in the quantitative analysis would not change the overall conclusions that costs would far exceed benefits for both alternatives and Cooling Towers are dominated by CWWS because of higher costs and lower benefits.
- These conclusions are also robust with respect to uncertainty analyses, including the sensitivity analysis and the Monte Carlo analysis. Even the sensitivity case with "all favorable" assumptions (leading to lower costs and higher benefits for each alternative than the base case assumptions) resulted in net costs for both CWWS and Cooling Towers. Moreover, all draws in the Monte Carlo uncertainty analysis produced results with net costs for both alternatives with lower benefits for Cooling Towers than for CWWS.
- The conclusions also do not change if one assumes that Cooling Towers could be operated continuously without regard for air permit considerations. Cooling Towers have lower benefits than CWWS even in this case.

I. Introduction

This report provides information on the costs and potential benefits of installing and operating either cylindrical wedgewire screens (CWWS) or closed-cycle cooling towers (Cooling Towers) at Indian Point Energy Center (IPEC). CWWS and Cooling Towers are being considered as a means of reducing impingement and entrainment mortality (I&E) at the cooling water intake structures (CWIS) of IPEC. Information on costs and benefits is important in assessing the public need and benefits of CWWS and Cooling Towers at IPEC, including social and economic considerations.

The report provides descriptions of the methodologies and data used to conduct the analyses. Our analyses build on engineering information developed by ENERCON Services for CWWS and Tetra Tech for Cooling Towers, as well as biological information developed by a team of expert biologists for the two technologies. We use well-established economic methods to develop social costs and social benefits estimates, drawing on guidelines developed by the U.S. Environmental Protection Agency (EPA), the U.S. Office of Management and Budget (OMB), and the economics literature (e.g., Boardman et al. 2011).

This chapter provides background on IPEC and the role of benefit and cost information in an environmental review. The final section provides an overview of the organization of this report.

A. Background on Indian Point Energy Center

IPEC is located in the Village of Buchanan in Westchester County, New York, on the eastern shore of the Hudson River. The 239-acre site includes three nuclear units owned by subsidiaries of Entergy Corporation ("Entergy"). Unit 1 is no longer generating electricity and is managed under the U.S. Nuclear Regulatory Commission's (NRC) SAFSTOR program pending final decommissioning. Units 2 and 3 have been in operation since 1974 and 1976, respectively. Their initial licenses from the NRC were set to expire in 2013 and 2015, respectively, but operations will continue under NRC's "timely renewal" mandate. Assuming NRC approval of Entergy's applications to obtain 20-year renewals, Units 2 and 3 will operate until 2033 and 2035, respectively. Units 2 and 3 have maximum dependable net capacities of 1020 megawatts (MW) and 1040 MW, respectively (NYISO 2013, p. 30). IPEC is the largest baseload power source in southeastern New York (NYISO 2013, p. 48).

IPEC uses water from the Hudson River to cool both operating units. The intakes and discharges are authorized by a joint NYSDEC-issued State Pollutant Discharge Elimination System (SPDES) permit. The units use once-through cooling systems, but over the years have undertaken various measures to minimize I&E. Measures in the current configuration include optimized Ristroph-type traveling screens with low-pressure washes and a state-of-the-art fish return system, as well as multispeed pumps that reduce the flow of water to allow for efficient operation of the units with reduced water use.

As part of the renewal process for the SPDES permit, NYSDEC Staff has recommended Cooling Towers (i.e., the use of Cooling Towers to reuse cooling water) as BTA for the NRC-approved license-renewal period if that technology is demonstrated to be available and if it receives the required permits. Entergy is proposing installation of CWWS.

B. Background on Benefit and Cost Assessments and SEQRA

An analysis of benefits and costs complies with the scope of environmental impact statements (EIS) based on New York's State Environmental Quality Review Act (SEQRA). Section 617.9(b)(2) of 6 New York Codes, Rules, and Regulations (NYCRR) states that a draft EIS "must include... a concise description of the proposed action, its purpose, public need and benefits, including social and economic considerations." Section 617.11(d)(2) states that an agency's SEQRA finding must "weigh and balance relevant environmental impacts with social, economic and other considerations." New York's SEQRA Handbook also notes that "in the findings which must be issued after a final EIS is completed, environmental impacts or benefits may be balanced with social and economic considerations" (NYSDEC 2010, p. 87).

This report provides information on benefits and costs of the two technologies in accordance with SEQRA regulations. We develop estimates of the costs and benefits of CWWS and Cooling Towers relative to the current configuration. These comparisons allow us to develop conclusions regarding the economic desirability of the two technologies.

For consistency, we express all costs and benefits in this report in constant 2012 dollars. We convert all flows of costs and benefits to present values by discounting them back to a common date, January 1, 2013. Moving the date for the present value calculations would simply scale costs and benefits up or down by the same proportion. In computing present values, we apply real (net of inflation) discount rates of 3 and 7 percent in keeping with OMB and EPA guidelines (OMB 1992, OMB 2003, EPA 2010).

C. Organization of This Report

The remainder of this report is organized as follows.

Chapter II provides a brief overview of CWWS and Cooling Towers and how they could be installed at IPEC.

Chapter III provides information on the costs of CWWS and Cooling Towers. Three types of costs are estimated.

1. *Capital costs* are one-time costs associated with acquiring, constructing, and installing equipment for CWWS and Cooling Towers.

2. *Operation and maintenance (O&M) costs* are recurring costs associated with operation and maintenance of the equipment for CWWS and Cooling Towers, with the exception of any costs related to ongoing electricity losses.

3. *Electricity costs* represent the costs to society related to changes in net electricity output at IPEC due to CWWS and Cooling Towers.

Chapter IV summarizes our estimates of the potential social benefits of CWWS and Cooling Towers. We provide an overview of the various types of benefits that are potentially applicable to cooling water intake alternatives and determine their relevance to the specific circumstances at IPEC, based on the biological information that has been developed. The calculations are theoretical because as noted below, expert biologists have concluded that reducing I&E at IPEC may not actually increase fish populations or harvests. Thus, we refer to the benefit estimates as theoretical benefits.[3]

Chapter V provides comparative information on the benefits and costs of CWWS and Cooling Towers, computing the net benefits (i.e., benefits minus costs) of the two technologies. This information allows us to develop conclusions regarding the economic desirability of the two technologies. This chapter also provides information on the robustness of the conclusions with respect to cost and benefit assumptions as well as to cost and benefit categories that have not been quantified.

Chapter VI provides analyses of uncertainties regarding the quantified costs and benefits. The analyses include sensitivity analyses and Monte Carlo analyses. We use these analyses to consider the robustness of the conclusions with regard to cost and benefit uncertainties.

Chapter VII summarizes the conclusions of the study.

The appendices to our report provide details on our methodologies for analyzing the social cost of replacement power (Appendix A), commercial and recreational harvest percentages (Appendix B), commercial fish values (Appendix C), recreational fish values (Appendix D), potential non-use benefits (Appendix E), potential indirect use benefits (Appendix F), and uncertainty using Monte Carlo methods (Appendix G). Appendix H provides estimated results under an alternative assumption regarding the time during the year in which Cooling Towers could be operated.

3 To avoid awkward phrasing, in some parts of the report we do not "theoretical" in our description of benefit metrics but all the estimates are understood to be theoretical because of the biological assessments noted in the text.

II. Overview of Cylindrical Wedgewire Screens and Cooling Towers

This chapter provides overviews of the nature of I&E, the current technologies and operational measures at IPEC that reduce I&E, and CWWS and Cooling Towers.

A. Overview of Impingement and Entrainment

The two IPEC generating units, like other nuclear and large fossil-fired plants, depend on cooling water and service water to operate safely and efficiently. The units draw cooling and surface water from the Hudson River through their own CWIS and, under certain conditions, service water through the CWIS for Unit 1, which no longer operates. Large pumps circulate most of the water through the units' cooling systems, where the water absorbs waste heat and is then discharged back to the river. Smaller pumps withdraw relatively modest amounts of service water.

Theoretically, CWIS can affect aquatic life in two primary ways:

1. *Impingement*: Fish—primarily small adult fish or juveniles of larger species—may be drawn against screens protecting the intake, and some of the impinged fish may suffer mortality. IPEC's current systems are "state-of-the-art" for impingement, as reflected in the requirements of EPA's proposed 316(b) Replacement Rule (EPA 2011).

2. *Entrainment*: Eggs and larvae of marine organisms may be drawn through the CWIS and into the plant, and some of the eggs and larvae may suffer mortality. IPEC's current systems reduce entrainment, but incremental entrainment reductions are the focus of our report.

CWWS reduce the number of aquatic organisms that are entrained through the CWIS, and thus lead to changes in impingement and entrainment. Similarly, Cooling Towers would reuse much of the water taken in, reducing the volume of intake water required and thereby lowering I&E.

B. Current Configuration

In some evaluations, NYSDEC has assessed the effectiveness of alternative I&E reduction technologies relative to a "regulatory baseline" set of conditions. The regulatory baseline conditions include relatively simple intake screens designed and operated only for debris removal, full-flow operation for 365 days per year, and assumes no survival for impinged or entrained organisms.

Current controls and conditions at IPEC reduce I&E below the regulatory baseline level through several mechanisms.

1. Unit 2 has dual-speed pumps and Unit 3 has variable-speed pumps that enable plant operators to reduce the flow of cooling water for efficient operation.

2. The units have Ristroph-type traveling screens and a fish return system that minimize impingement mortality.

3. The units have relatively low temperature differentials across the condensers, thus reducing entrainment mortality from the regulatory baseline level.

4. Each unit undergoes periodic shutdowns for refueling (staggered so that the two units do not have shutdowns at the same time) typically during the spring season, thus reducing I&E.

Our estimates of the costs and theoretical benefits of CWWS and Cooling Towers initially are measured relative to the current configuration that includes these controls and conditions. In the absence of the installation of new I&E reducing technologies, the current configuration would continue to reduce I&E at IPEC over the time period of our analysis. The current configuration is therefore the appropriate initial "baseline" for the benefit-cost analysis of the two alternatives.

C. Cylindrical Wedgewire Screens

CWWS consist of specially designed screens made with wedge-shaped wires. With CWWS installed, the units at IPEC would withdraw water from the river through these structures. This modification to the CWIS would reduce I&E in three ways:

1. Through established mechanical forces, organisms are swept past the intake by the tidal flow in the Hudson River.

2. The large screen area reduces flow rates through the screens, thus facilitating behavioral avoidance and therefore I&E.

3. To a lesser degree, they provide a physical barrier preventing organisms larger than the screen spacing from being entrained.

ENERCON and the biological team investigated several alternative configurations for the screens that vary in the spacing of the slots and the velocity of water flowing through the screens (which is inversely proportional to the surface area of the screens). Entergy's proposed design includes a screen configuration with a slot size of 2 mm and through-screen flow velocity of 0.25 feet per second (ENERCON 2013a).

ENERCON's analysis indicates CWWS could be installed at IPEC over a period of six years (ENERCON 2013a). Assuming a start date of mid-2018, this assumption means that CWWS would become operational in 2024.

D. Closed-Cycle Cooling Towers

Under the Cooling Towers alternative, IPEC theoretically could install closed-cycle cooling systems that could reduce the volume of water withdrawn from the Hudson River by up to approximately 97 percent, if operated on a year-round basis. In fact, however, ENERCON

(2013b) has evaluated Cooling Tower designs by the two consultants engaged by NYSDEC Staff and Riverkeeper, and concluded that neither design likely is feasible. The design proposal from Tetra Tech on behalf of NYSDEC Staff (Tetra Tech 2013) is more fully developed than the design proposal from Riverkeeper, which ENERCON has determined is materially deficient. Thus, we rely upon the Tetra Tech report for information related to the cost and effectiveness of Cooling Towers.

Tetra Tech's analysis assumes Cooling Towers would take between 7 and 9 years to install, although it also provided estimates for stages in the permitting and construction process that together add up to roughly 8-12 years.[4] Given the uncertainty of Tetra Tech's own estimates, and in an effort to be conservative, we took the midpoint of the smaller (7-9 year) range and, assuming that the permitting period begins in mid-2018, we assumed that Cooling Towers would be operational in mid-2026. If we had used the midpoint of the longer (8-12 years) range instead, we would have assumed a start date for Cooling Towers in 2028. According to both ENERCON (2010b) and Young/Sommer (2013), a period of much longer than eight years would be required for permitting and construction of Cooling Towers at IPEC. Our assumption that Cooling Towers are operational in 2026 results in a longer operational period for Cooling Towers than would the use of other Tetra Tech, ENERCON (2010b) or Young/Sommer (2013) estimates, and hence greater biological benefits.

We supplement the Tetra Tech information on Cooling Towers where the information is incomplete. In particular, as discussed in Chapter 2 of TRC (2009), operation of the Cooling Towers would not comply with air emissions permitting requirements in some periods of the year, a factor that was not assessed by Tetra Tech. Thus, we presume that Cooling Towers would only be operated when operation would not violate air quality constraints. ENERCON (2010a) and ASAAC (2013) provide information on the implications of these constraints for operation of the Cooling Towers and their biological benefits. Appendix H to this report provides cost and benefit results if air emissions permitting requirements did not constrain operation of the Cooling Towers.

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4 The following are commentaries on the timing of individual stages for Cooling Towers in Tetra Tech (2013). "It is not unreasonable to assume the permitting effort alone would take 3 to 5 years, while the final design effort required to produce construction-level plans and drawings could easily lag behind final approval by 1 year or more." (p. 27). "Construction could occur over a period of approximately 4-6 years." (p. 77).

III. Costs of Cylindrical Wedgewire Screens and Cooling Towers

This chapter provides information on the costs of CWWS and Cooling Towers. We first provide an overview of the basic cost methodology. We then develop estimates for the three major categories of costs: (1) capital costs; (2) operation and maintenance costs; and (3) electricity costs. The final section presents total quantified costs for CWWS and Cooling Towers.

A. Overview of Cost Methodology

To measure the potential costs of a regulatory-based decision, the appropriate measure is social costs, as noted in the EPA *Guidelines for Preparing Economic Analyses* ("*Guidelines*") (EPA 2010):

> Social cost represents the total burden that a regulation will impose on the economy. It is defined as the sum of all opportunity costs incurred as a result of a regulation where an opportunity cost is the value lost to society of any goods and services that will not be produced and consumed as a result of a regulation. These opportunity costs consist of the value lost to society of all the goods and services that will not be produced and consumed if firms comply with the regulation and reallocate resources away from production activities and towards pollution abatement (EPA 2010, pp. 8-1, 8-2).

Although the *Guidelines* deal with regulatory decisions, the general principles they present are valid for comparisons of benefits and costs, including this analysis of CWWS and Cooling Towers at IPEC.[5]

When the effects of a regulation or a regulatory-based decision are primarily confined to a small number of efficient markets,[6] it is appropriate to focus the cost assessment on changes in the specific market in which the costs are imposed[7] (EPA 2010, p. 8-2). In that case, the social cost of a particular regulatory-based decision is equal to the sum of the compliance costs and any changes in economic efficiency (or "deadweight loss") that may result (EPA 2010, p. 8-3). As long as any price impacts are negligible, the deadweight loss is not significant and compliance costs provide a sufficiently complete measure of the conceptually appropriate measure of costs (Boardman et. al 2011, p. 99). We assume that the compliance costs related to CWWS and Cooling Towers at IPEC would not affect electricity prices, and thus that the compliance costs would not result in any loss in economic efficiency. We do, however, include the possibility of inefficiencies related to the electricity market; in particular, we consider changes in air emissions that are not covered by the market prices of electricity.

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5 Note that similar principles are developed in textbooks on benefit-cost analyses (see, e.g., Boardman et al. 2011).

6 An "efficient market" does not have distortions that affect social welfare. In an efficient market, for example, there are no costs that are imposed on others that are not incorporated ("internalized") in the market.

7 This analysis is referred to in economics as a "partial equilibrium analysis" to distinguish it from a "general equilibrium analysis" in which potential effects on other markets are incorporated in the analysis.

Compliance costs are generally composed of two main components: (1) capital costs; and (2) operating costs (EPA 2010, p. 8-8).[8] Because costs are incurred in future years, we use social discount rates to convert them into present values and thus enable comparisons with benefits, as recommended in the EPA *Guidelines* (EPA 2010, p 8-10).

1. Components of Compliance Costs

As noted above, compliance costs are generally composed of capital costs and operating costs (EPA 2010, p. 8-8). It is useful, however, to distinguish costs related to changes in IPEC electricity generation and capacity from other operating costs. It is also useful to include maintenance costs with operating costs, both of which are generally incurred each year. Thus, to assess the compliance costs of installing and operating CWWS and Cooling Towers at IPEC, we use the following three categories:

1. *Capital costs* are one-time costs associated with acquiring, constructing, and installing equipment.

2. *Operation and maintenance (O&M) costs* are recurring costs associated with operation and maintenance of the equipment, with the exception of any costs related to ongoing power losses.

3. *Electricity costs* represent the costs to society related to changes in net electricity generation at IPEC. The social costs associated with these changes include the materials (e.g., fuels) and other costs incurred to supply energy, capacity and ancillary services in order to replace changes in electricity output at IPEC. As noted, the costs may include other "external" costs associated with changes in generation (e.g., certain air emissions).

2. Information Used in Cost Assessments

Information on the costs of CWWS is from ENERCON (2013a), whereas information on the costs of Cooling Towers is from Tetra Tech (2013). As noted above, we supplement the Tetra Tech information where it is incomplete. In particular, as explained in Chapter II, we presume that Cooling Towers would only be operated when operation would not violate air quality constraints. Neither Tetra Tech (2013) nor NYSDEC Staff provided information on the operating implications of the air quality constraints, and thus we rely upon ENERCON (2010a, 2013a) for information on the implications of air permit restrictions on generation at IPEC after Cooling Towers are installed.

We use the current plant conditions as the baseline from which we measure the costs of CWWS and Cooling Towers. These current conditions include the current use of Ristroph screens as well as other technologies and operational measures. As discussed below, the net electricity impacts

[8] As the *Guidelines* note, there are other potential categories of social costs beyond compliance costs. These include transaction costs, government regulatory costs, transitional costs and distributional costs (EPA 2010, p. 8-9). We assess these other social costs in Chapter V.

of CWWS and Cooling Towers reflect changes in the use of the Ristroph screen technology if these other two technologies were in place.

As noted, we express all cost estimates in constant 2012 dollars. We calculate all present values as of January 1, 2013. These choices of constant dollars and beginning date for the calculation of present values do not make a material difference in the results. In computing present values we use real (net of inflation) discount rates of 3 and 7 percent, as recommended by OMB (1992, 2003) and EPA (2010).

Costs are projected until September 2033 for Unit 2, which would be the end of the 20-year license extension for which Entergy is applying at the NRC. Similarly, for Unit 3, costs are projected until December 2035, when the equivalent 20-year license extension would end.

B. Capital Costs

Capital costs consist of the labor and material costs associated with the acquisition, construction, and installation of the two alternatives. In this section we provide estimates of the total overnight construction costs and the construction costs discounted to present value terms when account is taken of the potential timing of costs.

1. Overnight Capital Costs

Overnight capital costs are engineering estimates of the total costs of installing the necessary structures and equipment based on contemporary prices for materials, equipment, and labor, assuming the modifications could be completed immediately (i.e., "overnight"). Thus, they exclude interest charges during construction, which engineering cost estimates sometimes include; discounting implicitly incorporates such interest charges because earlier expenditures receive more weight in the present value calculations.

ENERCON (2013a) provides estimates of the costs of CWWS at IPEC. The cost estimates provided in ENERCON (2013a) include elements related to an air burst system but some additional costs may be involved if experience indicated that additional elements were required for proper operation of the CWWS.

Tetra Tech (2013) provides estimates of the overnight capital costs of its design for Cooling Towers. These estimates do not account for the modifications that would be required for the towers to be operated intermittently. We understand that no detailed engineering analysis has been conducted on the additional construction costs to allow intermittent operation of the Cooling Towers, but we assume that adding that capability would increase capital costs. Thus, the estimate provided by Tetra Tech (2013) will underestimate the overnight capital cost of the Cooling Towers required at IPEC.

The cost estimates from ENERCON (2013a) and Tetra Tech (2013) have been adjusted in various ways to make the costs for CWWS and Cooling Towers as comparable as possible. First, Tetra Tech (2013) does not provide information on costs related to designing and permitting the Cooling Towers, so the estimates from ENERCON (2013a) do not include any design and permitting costs for CWWS either. Second, ENERCON (2013a) does not include contingency costs in the capital cost estimates for CWWS (although a range of uncertainty underlying the capital cost estimate is included, as discussed in Chapter VI), so we removed the contingency costs assumed by Tetra Tech (2013) for the Cooling Towers (25 percent of total direct and indirect construction costs). The result of excluding design, permitting and contingency costs is that the total costs of both alternatives will be understated to some extent, and hence both alternatives will appear more attractive than otherwise in comparison to the current configuration.

Table 1 summarizes the overnight construction costs of CWWS and Cooling Towers based upon ENERCON (2013a) and Tetra Tech (2013), with the modifications summarized above.

Table 1. Capital Overnight Costs ($millions)

Alternative	Overnight Cost
CWWS	$223.2
Cooling Towers	$822.2

Note: All dollar values are in millions of constant 2012 dollars.
Construction costs exclude design, permitting, and contingency costs.
Source: ENERCON (2013a), Tetra Tech (2013) and NERA calculations as explained in text

2. Present Value of Capital Costs

We use information from ENERCON (2013a) and Tetra Tech (2013) on the duration of each phase of construction for CWWS and Cooling Towers. This information allows us to determine the construction expenditures that would be incurred in each year and then discount the future costs to present value terms.

ENERCON (2013a) indicates that CWWS at IPEC could be installed over a period of six years. First, the design phase of the project is projected to last approximately two years, which we assume begins in July of 2018. In-river construction activities would take place in the following three years, with procurement costs for construction materials beginning the year before construction starts. The final "tie-ins" of the CWWS would follow the in-river construction and would be coordinated with refueling outages at IPEC. Based on the estimated six year duration of the project and the assumed start date of July of 2018, CWWS would begin operation in July of 2024.

For Cooling Towers, we also assume that permitting would begin in July of 2018. Tetra Tech (2013) provides information on the timing of permitting and construction. Based on the information provided in Tetra Tech (2013) and as discussed above, we presume that design and permitting would take place during the years 2018 to 2021 and that construction would occur during the years 2021 to 2026.[9] Using the Tetra Tech timing assumptions, the Cooling Towers would begin to operate in July of 2026.

[9] According to Tetra Tech (2013), the complete implementation of the Cooling Towers project (including design, permitting, construction, tie-in and testing) would last from seven to nine years. We take the mid-point of this range and assume the full project takes eight years, three years for permitting/design and five years for

ENERCON (2013a) and Tetra Tech (2013) also provide information on when the capital expenditures would be incurred for CWWS and Cooling Towers, respectively. We use that information to develop estimates of the present values of capital expenditures. Table 2 shows the construction costs of CWWS and Cooling Towers based upon these expenditures discounted to present value terms at 3 and 7 percent discount rates. The construction start and end dates refer to the dates on which permitting would begin and construction activities would end. The construction costs for Cooling Towers do not include the costs due to the forced outage of IPEC during construction; these electricity system costs are discussed below.

The present value of capital costs for CWWS as of January 1, 2013 are $173.9 million using a 3 percent discount rate and $126.2 million using a 7 percent discount rate. The present value of construction costs for Cooling Towers are $595.2 million using a 3 percent discount rate and $393.6 million using a 7 percent discount rate. Note that the present values of capital costs are substantially lower than the overnight costs because the costs would be incurred over many years in the future.

Table 2. Present Value of Capital Costs ($millions)

Alternative	Discount Rate r = 3%	Discount Rate r = 7%	Project Start Date	Project End Date
CWWS	$173.9	$126.2	Jul 2018	Jun 2024
Cooling Towers	$595.2	$393.6	Jul 2018	Jun 2026

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. Project timelines include design, permitting, construction and final tie-ins.
Source: ENERCON (2013a) and Tetra Tech (2013) and NERA calculations as explained in text

ENERCON (2010b) and Young/Sommer (2013) have provided alternative estimates of the time required for permitting and construction of Cooling Towers at IPEC, and conclude that Cooling Towers would require substantially more time to develop and install than presumed in Tetra Tech (2013).

C. Operation and Maintenance Costs

Both CWWS and Cooling Towers would involve the installation of equipment that would require ongoing upkeep. Maintaining this equipment entails O&M costs. Those costs include labor, materials, and outside services. In addition, both of the technologies would involve changes in the use of the existing Ristroph screens, and thus the net O&M costs depend upon changes in the usage and costs of the Ristroph screens. The following subsections provide information on the O&M costs of the various technologies and the net O&M costs of CWWS and Cooling Towers. Note that ongoing electricity costs are considered separately below.

construction. As noted above (p. 6), however, the specific information on the timing of individual tasks yields a wider range of 8 to 12 years to complete construction, assuming no overlap between the stages.

1. Ristroph Screens Operation and Maintenance Costs

We rely upon Entergy for information on the O&M costs for the existing Ristroph screens. Entergy (2013a) estimates that annual O&M costs for the existing Ristroph screens are $2.8 million (in 2012 dollars). For both CWWS and Cooling Towers, Entergy anticipates that the Ristroph screens would continue to be operated, although the costs are expected to be lower than under current operations. The estimates of net O&M costs for CWWS and Cooling Towers therefore reflect some cost savings from reducing the need for the existing Ristroph screens.

For CWWS, Entergy (2013a) estimates that O&M costs related to Ristroph screens would decrease by 60 percent, or about $1.7 million. The remaining 40 percent of O&M costs—estimated at $1.1 million—would still be incurred for testing and other activities needed to keep the existing Ristroph screens available for potential reinstallation and use.

For Cooling Towers, as noted in Chapter II, ENERCON (2010a) estimates that the Cooling Towers operation could vary by month—operating on average about 13 percent of the time over the course of the year—in order to comply with air quality regulations. The Ristroph screens would not be used when the Cooling Towers were operating but would be used for the remaining 87 percent of the time when Cooling Towers were not operating. The O&M costs of the Ristroph screens are assumed to decrease in proportion to the decrease in usage of the screens. On average, the monthly O&M costs associated with Ristroph screens would decrease by 13 percent—or about $0.4 million—under the Cooling Tower alternative. The remaining 87 percent of annual O&M costs—estimated at $2.4 million —would still be incurred for the Ristroph screens.

2. CWWS Operation and Maintenance Costs

ENERCON has not provided information on the (non-electricity) O&M costs associated with the CWWS at IPEC. Our cost estimate will therefore be understated by the amount of any potential O&M needed for the CWWS. We would not expect these O&M activities, which presumably include periodic defouling of the screens, to involve costs that are significant relative to construction costs.

3. Cooling Towers Operation and Maintenance Costs

Tetra Tech (2013) provides estimates of the O&M costs that would be incurred to operate the Cooling Towers. These include expenditures for labor, equipment maintenance, and water treatment chemicals. O&M costs are projected to increase over time due to additional periodic costs to repair and replace equipment as it ages, such as fill material, spray heads, fan blades and gear boxes. We understand that there is much uncertainty surrounding the actual O&M costs that would be required for Cooling Towers at IPEC, but due to the absence of alternative information, we use the estimates provided by Tetra Tech.

Tetra Tech (2013) estimates that annual O&M costs for Cooling Towers are $2.5 million for the first five years of operation, $3.8 million for the next ten years, and $4.4 for the following five years. As noted above, we assume that Ristroph screens operate when the Cooling Towers are not operating.

The annual O&M costs for Cooling Towers and Ristroph screens are assumed to decrease in proportion to their respective operation percentages. The limited use of Cooling Towers due to air quality constraints means that the annual O&M costs for Cooling Towers are lower than the values in Tetra Tech (2013), which do not take into account air quality constraints. The Tetra Tech (2013) cost estimates are therefore decreased in proportion to the assumed reduction in usage of the Cooling Towers based on the operational schedule developed by ENERCON (2010a). On average, the monthly O&M costs for Cooling Towers thus are reduced by 87 percent from the Tetra Tech (2013) cost estimates.

4. Net Operation and Maintenance Costs

Table 3 summarizes the estimated annual O&M costs for Cooling Towers, including the cost savings from the reduced usage of the existing Ristroph screens. The table shows that the net O&M costs for Cooling Towers differ by year over the relevant time frame covered by our analysis.

Table 3. Annual O&M Costs ($millions)

Alternative	New Tech. O&M Costs	Ristroph O&M Savings	Net O&M Costs
CWWS	N/A	N/A	N/A
Cooling Towers			
Years 1-5	$0.33	$0.37	-$0.05
Years 6-15	$0.49	$0.37	$0.11

Note: All values are in millions of constant 2012 dollars per year of operation for both units combined. "Year 1" represents the first year following completion of the Cooling Towers (i.e. 2026 to 2027). We assume Ristroph screens will not operating during a plant outage, so additional O&M savings is incurred during the Cooling Tower construction outage period.
Source: Entergy (2013a), Tetra Tech (2013) and NERA calculations as explained in text

Table 4 shows the present values of net O&M costs discounted at 3 and 7 percent. The calculations incorporate the assumption that Ristroph screens will not operate during the Cooling Tower construction outage period, leading to additional cost savings for the Cooling Tower alternative. The present values of O&M costs for Cooling Towers result in net savings of $1.09 million using a 3 percent discount rate and $0.69 million using a 7 percent discount rate.

Table 4. Present Values of O&M Costs ($millions)

	Discount Rate	
Alternative	r = 3%	r = 7%
CWWS	N/A	N/A
Cooling Towers	-$1.09	-$0.69

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars.
Source: NERA calculations as explained in text.

D. Electricity Costs

This section considers the social costs related to changes in IPEC's contributions to the electricity system due to CWWS and Cooling Towers. As noted below, market prices for electricity are used to value changes in electricity output at IPEC due to the construction and operation of CWWS and Cooling Towers.

1. Potential Types of Electricity Costs

The construction and operation of a technology change to the CWIS at IPEC could have three potential effects on IPEC's contributions to the electricity system:

1. *Construction outages.* This category refers to reductions in the electricity output of the plant when a new technology requires an outage that is in addition to the regularly-scheduled maintenance outages of the plant.
2. *Efficiency losses.* This category refers to reductions in the electricity output of the plant when a new technology decreases the efficiency of electricity generation at the plant.
3. *Parasitic losses.* This category refers to reductions in the electricity output of the plant when a new technology requires energy from the plant.

2. Electricity Costs from Construction Outages

ENERCON (2013a) has determined that installation of CWWS would not lead to a reduction in electricity output due to construction outages. Because the tie-ins of the CWWS to the two units at IPEC would be coordinated with scheduled refueling outages, no incremental electricity output losses would be incurred during construction.

Tetra Tech (2013) indicates that an additional outage would be required for Cooling Towers. Table 5 summarizes Tetra Tech's (2013) estimates of the incremental reductions in net electricity output due to the additional outage period. The reductions reflect 35 weeks of shutdown of both units at the end of the construction period, a period that is reduced by five weeks for Unit 2 on the presumption that the tie-in would coincide with a scheduled maintenance outage for Unit 2. Note that based upon the construction schedule noted above, these generation losses due to the Cooling Towers are projected to occur in the 2025-2026 time frame.

Table 5. Construction-Related Reductions in Net Electricity Output

Technology	MWh
CWWS	0
Cooling Towers	11,136,096

Note: MWh is megawatt-hours
Source: Tetra Tech (2013), ENERCON (2013a)

3. Net Changes in Operational Efficiency

ENERCON (2013a) estimates that because the current electricity required for condenser backwashing would not be required when CWWS was installed, replacing the continuous operation of Ristroph screens with CWWS would lead to electricity gains. ENERCON (2013a) estimates that the gains in electricity output at IPEC would be 600 MWh per year.

Tetra Tech (2013) estimates that the operating efficiency of IPEC would be reduced if Cooling Towers were installed. Tetra Tech (2013) estimates that Cooling Towers would lead to average annual capacity reductions of 16 MW at Unit 1 and 4 MW at Unit 2. These annual estimates were weighted by month using monthly efficiency loss estimates from ENERCON (2013b). Based upon the Cooling Towers operational schedule developed by ENERCON (2010a), this reduction would translate into an annual loss in electricity output of 22,783 MWh per year.

Table 6 summarizes the losses in electricity output due to operational efficiency effects of CWWS and Cooling Towers based upon this information. Losses in efficiency result in social costs. Note that because CWWS would result in efficiency gains, the entry for CWWS is negative, meaning that instead of costs there would be social benefits due to efficiency effects of CWWS.

Table 6. Annual Efficiency Losses (MWh)

	Efficiency Losses
CWWS	-600
Cooling Towers	22,783

Note: Negative value represents an increase in electricity output at IPEC.
Source: ENERCON (2013a), Tetra Tech (2013)

4. Net Changes in Parasitic Losses

There would be two partially offsetting changes related to parasitic losses due to the operation of CWWS and Cooling Towers:

1. *Added electricity needed to operate either CWWS or Cooling Towers.* The operation of either CWWS or Cooling Towers would require electricity and thus reduce the net electricity output of IPEC.

2. *Reduced electricity needed to operate the Ristroph screens.* The use of either CWWS or Cooling Towers would reduce the hours in which the Ristroph screens would be operated. This change would increase the net electricity output of IPEC relative to the existing conditions.

The net effect on parasitic losses—and thus on the generation and capacity of IPEC—thus depends upon the combination of these two factors.

a. Parasitic Losses from Ristroph Screens

With the operation of either CWWS or Cooling Towers, electricity would be saved by reducing the need to run the existing Ristroph screens. The Ristroph screens use approximately 9,400 MWh of electricity annually (ENERCON 2013a).

For the CWWS alternative, the Ristroph screens would be tested and operated only occasionally to ensure their continued availability. Entergy (2013b) estimates that power requirements would be reduced by roughly 90 percent, which means that existing parasitic losses would be reduced by 8,460 MWh annually.

For the Cooling Towers alternative, we assume the parasitic losses from Ristroph screens decrease in proportion to the usage of Cooling Towers. Based on the operating schedule developed by ENERCON (2010a), the existing parasitic losses would be reduced by 1,128 MWh annually.

b. Parasitic Losses from CWWS

According to ENERCON (2013a), the initial construction of the CWWS air burst system would not include components of an air-burst system that would require electricity. We therefore assume there are no parasitic losses associated with the operations of CWWS at IPEC. To the extent that the air-burst system is needed and parasitic losses result, our cost estimated will be understated. However, we would not expect these losses to involve costs that are significant relative to construction costs.

c. Parasitic Losses from Cooling Towers

Tetra Tech (2013) notes that cooling towers would require electricity to operate its fans and pumps. Tetra Tech (2013) estimates that operating the cooling towers would result in a loss of capacity of roughly 40 MW, which, under the Cooling Towers operational schedule developed by ENERCON (2010a), corresponds to a reduction in electricity output of 47,187 MWh annually.

d. Net Changes in Parasitic Losses for CWWS and Cooling Towers

Table 7 summarizes estimates of the changes in parasitic losses due to the operation CWWS and Cooling Towers. Table 7 shows that on net, CWWS would lead to a savings of 8,460 MWh annually because of the avoided parasitic losses of the Ristroph screens. In contrast, the Cooling Towers alternative would lead to losses of 46,059 MWh annually.

Table 7. Changes in Annual Parasitic Losses (MWh)

	Direct Parasitic Losses	Avoided Parasitic Losses	Net Parasitic Losses
CWWS	0	-8,460	-8,460
Cooling Towers	47,187	-1,128	46,059

Note: Negative values represent increases in electricity output at IPEC.
Source: ENERCON (2013a), Entergy (2013b), and NERA calculations as explained in text

5. Total Changes in Electricity Output due to CWWS and Cooling Towers

Table 8 provides estimates of the annual changes in electricity output at IPEC for CWWS and Cooling Towers due to the effects of the construction outage, efficiency losses and parasitic losses described above. The changes reflect the assumed timing of installation and operation of the CWWS and Cooling Towers at the two IPEC units. The calculations incorporate the assumption that Ristroph screens will not operate during the Cooling Tower construction outage period, leading to additional cost savings for the Cooling Tower alternative. The final row shows the undiscounted sum of the annual changes.

Table 8. Total Losses in Annual Electricity Generation (MWh)

	CWWS				Cooling Towers			
	Construction Outage Losses	Net Efficiency Losses	Net Parasitic Losses	Total Electricity Losses	Construction Outage Losses	Net Efficiency Losses	Net Parasitic Losses	Total Electricity Losses
2024	0	-300	-4,230	-4,530	0	0	0	0
2025	0	-600	-8,460	-9,060	2,233,008	0	-1,178	2,231,830
2026	0	-600	-8,460	-9,060	8,903,088	5,609	7,966	8,916,663
2027	0	-600	-8,460	-9,060	0	22,783	46,059	68,842
2028	0	-600	-8,460	-9,060	0	22,783	46,059	68,842
2029	0	-600	-8,460	-9,060	0	22,783	46,059	68,842
2030	0	-600	-8,460	-9,060	0	22,783	46,059	68,842
2031	0	-600	-8,460	-9,060	0	22,783	46,059	68,842
2032	0	-600	-8,460	-9,060	0	22,783	46,059	68,842
2033	0	-525	-7,403	-7,928	0	19,017	40,734	59,751
2034	0	-300	-4,230	-4,530	0	3,275	23,030	26,305
2035	0	-300	-4,230	-4,530	0	3,275	23,030	26,305
Total	0	-6,225	-87,773	-93,998	11,136,096	167,873	369,936	11,673,905

Note: Negative values represent increases in electricity output at IPEC.
Source: NERA calculations as explained in text

6. Wholesale Electricity Prices

We assume the changes in net generation at IPEC due to the installation and operation of CWWS and Cooling Towers would not in general significantly affect electricity prices or electricity consumption on an annual basis. Thus, we assume only that a decrease (increase) in IPEC generation would lead to an increase (decrease) in the electricity generated at other facilities. The increase (decrease) in generation at other facilities would lead to an increase (decrease) in the social costs of providing electricity to consumers. There could, however, be significant impacts on an hourly or daily basis.

Wholesale electricity prices provide estimates of the social costs of replacement electricity (or the social benefits of avoiding the need for electricity from other facilities) because they reflect the cost of supplying an additional unit of electricity to the grid.[10] We developed forecasts of monthly wholesale electricity prices over the relevant time period for a region consisting of New York City and Westchester County, New York to value replacement electricity at IPEC. These projections are based on annual wholesale electricity price projections from the U.S. Energy Information Administration (EIA) and historical data on wholesale electricity prices (for scaling the annual price projections into monthly projections) from the New York Independent System Operator (NYISO).[11] Appendix A describes our methodology and shows our monthly electricity price forecasts.

7. Social Costs of Changes in Electricity Output

Table 9 summarizes the present values of the estimated changes in social costs of providing replacement electricity as a result of changes in net generation at IPEC due to the installation and operation of CWWS and Cooling Towers. As the table shows, the installation of CWWS would lead to social benefits because IPEC generation is estimated to increase; the benefits are $4.4 million based on a 3 percent discount rate and $2.4 million based on a 7 percent discount rate. As noted above, because the tie-in for CWWS would take place during a planned refueling outage, no outage costs would be incurred.

Cooling Towers require an installation period that extends beyond the plant's annual planned outages. It is therefore necessary to account for the net costs that are incurred while the plant is not operational. The gross costs include the costs of replacement power generation.[12] But costs would be reduced due to reductions in costs at IPEC that would not be incurred during this outage period. As an estimate of these cost savings, we use an estimate from EIA (2013) that the variable O&M costs for a new nuclear power plant are $12.30 per MWh.[13] Taking each of these

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[10] A portion of IPEC's output is sold to utilities (electricity retailers) via power purchase agreements. Wholesale prices are the appropriate measure of social costs or benefits even with these agreements.

[11] As discussed in Appendix A, the electricity price projections developed by EIA reflect capacity and ancillary services as well as generation. Real-time, hour-ahead, and day-ahead wholesale electricity prices from NYISO, however, reflect only generation.

[12] As stated earlier, Unit 2 and Unit 3 will undergo construction outages of 30 and 35 weeks, respectively, during the installation of the Cooling Towers.

[13] U.S. EIA (2013) does not provide an estimate of O&M costs for existing nuclear units. EIA estimates the levelized cost of new generation resources in its 2013 Annual Energy Outlook. The value of $12.30 per MWh

components into account, the installation and operation of Cooling Towers would lead to social costs of $462.5 million based on a 3 percent discount rate, and $278.0 million based on a 7 percent discount rate.

Table 9. Present Values of Social Costs (Benefits) of Changes in Electricity Output at IPEC ($millions)

	Discount Rate	
Alternative	**r = 3%**	**r = 7%**
CWWS		
Parasitic and efficiency costs	-$4.4	-$2.4
Construction outage replacement power costs	$0.0	$0.0
Construction outage cost savings	$0.0	$0.0
Total	-$4.4	-$2.4
Cooling Towers		
Parasitic and efficiency costs	$24.5	$12.6
Construction outage replacement power costs	$532.5	$322.7
Construction outage cost savings	-$94.6	-$57.3
Total	$462.5	$278.0

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars.
Source: NERA calculations as explained in text

8. External Costs Related to Changes in Electricity Generation

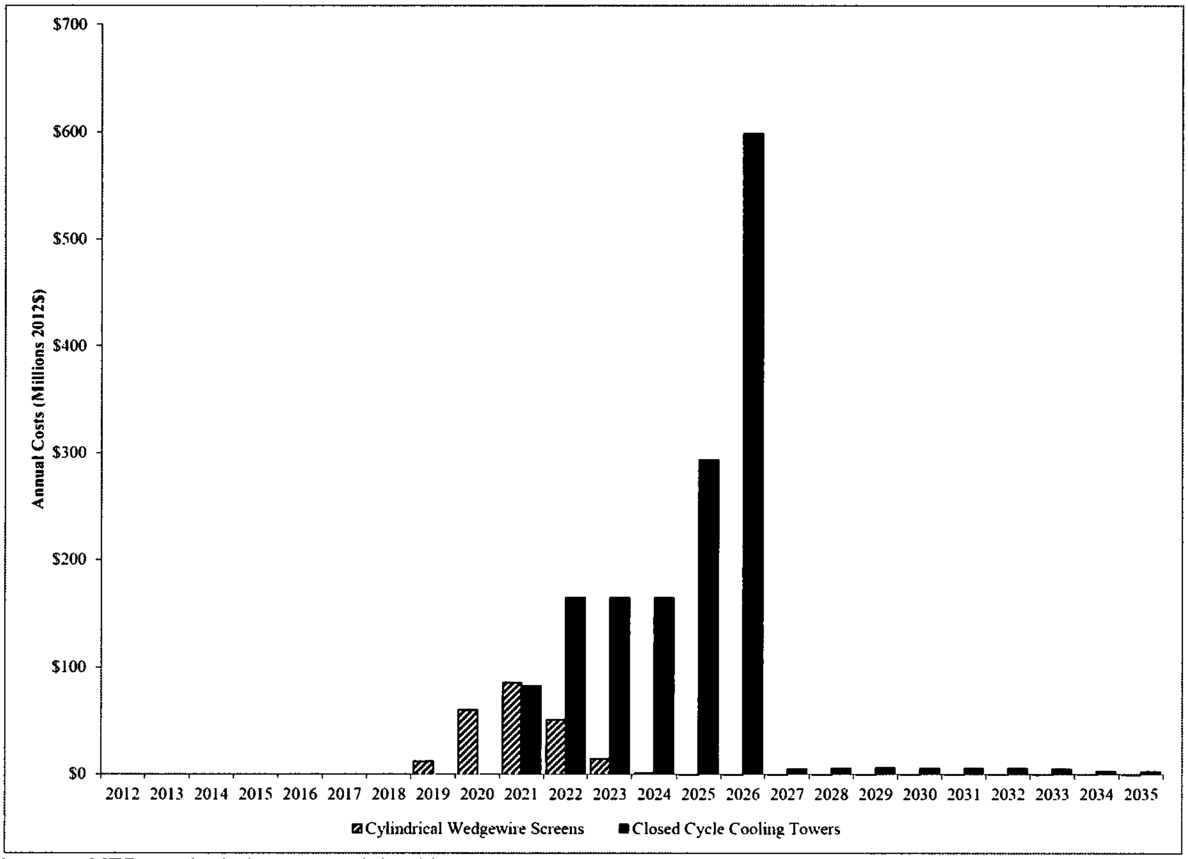
The social costs of changes in the sources of electricity generation should include external costs, i.e., costs such as air emissions that are not included in the market electricity prices. The wholesale electricity prices described above include the external costs of emissions covered by cap-and-trade programs, because overall emissions are capped and sources bidding into the system would include the cost of allowances needed to cover their emissions. In New York, the emissions covered by cap-and-trade programs are sulfur dioxide (covered by federal programs), nitrogen oxides (also covered by federal programs), and carbon dioxide (covered by the Regional Greenhouse Gas Initiative).

There are several potential sources of additional social costs related to air emissions that we have not quantified. The social costs of emissions not covered by cap-and-trade programs—such as mercury—are not incorporated in the wholesale electricity price forecast. In addition, the cap-and-trade programs noted above may not be binding in some years, in which case emissions from additional fossil generation would represent net additions rather than substitutes for other emissions. Our estimates assume these emissions caps are binding throughout our modeling period.

represents the average levelized variable O&M cost for an advanced nuclear plant entering service in 2018 in 2011 dollars, which we adjusted to 2012 dollars. This EIA value includes fuel costs as well as other costs that are assumed to vary with electricity output. The EIA value could overstate the potential cost savings if the full amount of fuel expenditures would not be saved during the construction outage period and/or if certain non-fuel variable O&M costs would not be saved during the outage period. If cost savings at IPEC are overstated, the net construction outage costs would be understated.

E. Total Quantified Costs

Figure 1 shows annual estimates of capital, O&M, and power costs for CWWS and Cooling Towers. Note that we use the same scale for the two alternatives to provide an accurate visual comparison of the relative costs.



Source: NERA calculations as explained in text

Figure 1. Annual Cost Estimates

Table 10 summarizes the present values of the estimated costs for CWWS and Cooling Towers. At a 3 percent discount rate, the present value of estimated total costs is $169.5 million for the CWWS alternative and about $1.1 billion for the Cooling Towers alternative; at this discount rate, Cooling Towers costs a little more than six times as much as CWWS. At a 7 percent discount rate the present values are lower, $123.8 million for CWWS and $670.9 million for Cooling Towers; at this discount rate, Cooling Towers costs a little less than six times as much as CWWS.

Table 10. Estimated Total Costs for CWWS and Cooling Towers

	Discount Rate	
Technology	**3%**	**7%**
CWWS		
Construction	$173.9	$126.2
O&M	N/A	N/A
Electricity	-$4.4	-$2.4
Total	$169.5	$123.8
Cooling Towers		
Construction	$595.2	$393.6
O&M	-$1.1	-$0.7
Electricity	$462.5	$278.0
Total	$1,056.6	$670.9

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars.
Source: NERA calculations as explained in text

IV. Benefits of Cylindrical Wedgewire Screens and Cooling Towers

This chapter provides estimates of the potential social benefits associated with reductions in I&E due to CWWS and Cooling Towers. The benefit estimates developed in this chapter are based on theoretical fishery harvest estimates developed by ASA Analysis & Communication (ASAAC 2013) for the current configuration, CWWS and Cooling Towers. As discussed in ASAAC (2013), biological analyses indicate that reducing I&E at IPEC would not increase fish populations or harvests, but ASAAC has developed theoretical calculations of harvest impacts nonetheless for the purposes of this analysis. Thus, we refer to the estimates provided by ASAAC (2013) as "theoretical biological impacts," and we refer to our benefit estimates as "theoretical benefits."

We first provide an overview of the general approach we use to evaluate theoretical social benefits, including background on the list of possible benefit categories. We then describe the methods for estimating individual theoretical benefit components. Detailed information on the methodologies and results are presented in Appendices B, C, D, and E.

A. Overview of Benefit Methodology

In estimating the theoretical benefits of the CWWS and Cooling Tower alternatives, we take the standard economic approach of using households' willingness-to-pay to estimate the value to society of the theoretical changes in fish harvests. That is, the social benefits are equal to the maximum amount of money that individuals as a group would voluntarily pay to obtain the environmental improvements, which in this case are the theoretical increases in various fish populations (or any other environmental improvements that might result). This approach is consistent with sound cost-benefit methodology (see, e.g., Boardman et al. 2011) and the approach set forth in the EPA *Guidelines* (EPA 2010, Chapter 7).

1. Possible Benefit Categories

a. Effect-by-Effect Approach to Determining Social Benefits

The overall social benefits of CWWS and Cooling Towers can be developed through an "effect-by-effect" approach that assesses the various relevant effects of the biological changes individually. This approach consists of separately evaluating the major effects of a given policy, and then summing the individual effects to develop an estimate of total social benefits (EPA 2010, p. 7-3). The EPA *Guidelines* note the following fundamental steps in this approach (adapted for this application):

1. Identify benefit categories potentially affected;

2. Quantify significant endpoints to the extent possible by working with biological experts; and

3. Estimate the value of these effects using appropriate valuation methods (EPA 2010, p. 7-3).

It generally is not possible or appropriate to develop monetary values for all potential benefit categories because some potential effects are likely to involve situations in which the likely benefits are small (relative to categories that are monetized) and the efforts to develop monetary values are expensive and imprecise. Therefore, it is important to focus monetization efforts on the benefit categories likely to be most significant and most amenable to quantification in monetary terms, with other effects evaluated qualitatively.

Determining which benefit categories to include in the monetary valuation requires making informed judgments on their likely significance. The EPA *Guidelines* provide the following criteria to determine which benefit categories to include in a benefit-cost analysis, criteria that we incorporate in our benefits analysis:

> Determine which benefit categories to include in the overall benefits analysis using at least the following three criteria:
>
> 1. Which benefit categories are likely to differ across policy options, including the baseline option? Analysts should conduct an assessment of how the physical effects of each policy option will differ and how each physical effect will impact each benefit category.
>
> 2. Which benefit categories are likely to account for the bulk of the total benefits of the policy? The cutoff point here should be based on an assessment of the magnitude and precision of the estimates of each benefit category, the total social costs of each policy option, and the costs of gathering further information on each benefit category. A benefit category should not be included if the cost of gathering the information necessary to include it is greater than the expected increase in the value of the policy owing to its inclusion. The analyst should make these preliminary assessments using the best quantitative information that is readily available, but as a practical matter these decisions may often have to be based on professional judgments.
>
> 3. Which benefit categories are especially salient to particular stakeholders? Monetized benefits in this category are not necessarily large and so may not be captured by the first two criteria (EPA 2010, p. 7-4).

As this excerpt from the EPA *Guidelines* suggests, the goal of a benefits assessment should be to identify significant benefit categories and assess them carefully, rather than to attempt to monetize every conceivable category. We develop monetary values for the major benefit categories and provide qualitative assessments of the other potential benefit categories, an approach that is consistent with EPA's *Guidelines* and economic guidance (see, e.g., Boardman et al. 2011).

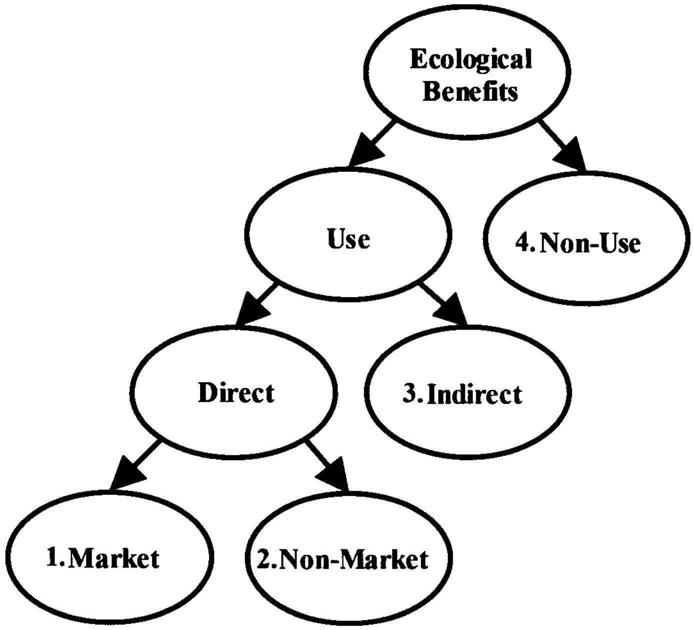
b. Major Components of Social Benefits

Social benefits reflect the values that individuals in society place on changes in fish populations that could result from the installation of CWWS or Cooling Towers at IPEC. As noted above, the social benefits are based upon households' willingness to pay for the biological gains (Boardman et al. 2011). The EPA *Guidelines* provide a summary of the benefit categories relevant to an assessment of ecological improvements, which is the general category of benefits relevant to this assessment. The EPA uses these benefit categories to develop estimates of monetary benefits in its proposed 316(b) Replacement Rule (EPA 2011). Economic treatises provide similar frameworks for categorizing benefits related to ecological improvements.[14]

Figure 2, adapted from the 2000 EPA *Guidelines* (EPA 2000) for assessing ecological benefits, provides a useful way of organizing and visualizing the relevant benefit categories. The figure divides the ecological benefits into two major categories: "use" benefits and "non-use" benefits. Use benefits consist of gains to those who use the additional resources provided by the various alternatives (e.g., commercial fishing), while non-use benefits consist of potential gains to those who do not experience any direct gains (e.g. those who might value changes in the numbers of fish without an expectation of future use). Use benefits can be further subdivided into three subcategories—market benefits (e.g. commercial harvest), non-market benefits (e.g. recreational harvest and catch-and-release), and indirect benefits (e.g. forage fish)—resulting in a total of four potentially relevant general ecological benefits categories.[15]

[14] See, e.g. Kolstad (2011, pp. 138-140), Boardman et al. (2011, Chapters 4 and 9), and Freeman (2003, Chapters 5 and 13).

[15] The 2010 *Guidelines* provide a table (EPA 2010, p. 7-9) that includes a list of examples of benefit categories for ecological improvements that is broadly consistent with the figure in the 2000 *Guidelines*.



Source: EPA (2000, p. 70); see also EPA (2010, p. 7-9)

Figure 2. Summary of Benefit Classification Scheme from EPA *Guidelines*

Of these categories, market benefits and non-market benefits are considered direct benefits because they involve direct benefits to users. The other category of use benefits—indirect benefits—relates to ecosystem benefits that accrue to users through indirect paths and can include both market and nonmarket effects. These use-benefit categories relate to the gains that individuals may obtain from use of the ecological resource, in this case the additional fish from reduced I&E at IPEC. The non-use benefits category consists of benefits that are not associated with any direct use by people, such as existence value.

2. Assessment of Specific Benefit Categories to Be Quantified

The theoretical benefits of CWWS or Cooling Towers at IPEC are based on the theoretical increases in harvests (i.e. commercial and recreational fishing harvests) of various species of fish. We assume that the baseline I&E impacts on fish harvests reflect recent historical conditions at IPEC and that these conditions will continue in the future at the same levels if no changes are made to IPEC's cooling water intake structures. Fish harvest measures the additional fish caught and kept by commercial and recreational fishermen.

Fish species that are not harvested and thus do not have a monetary value still contribute to the theoretical harvest benefits because such "forage" species may be eaten (either as live prey or dead biomass) by predator species with a monetary value. Moreover, individual game fish that are not harvested (and instead die of natural causes) may also be eaten by predator species with monetary value. Thus, as discussed above, the theoretical increases in fish harvests include the "direct" effects of reducing I&E for valued species as well as the "indirect" effects of making more prey and biomass available to valued predator species.

This section describes our methodologies for estimating the potential benefits of I&E reductions at IPEC. As discussed in Appendix E, we are not aware of any study of non-use benefits that could be used to develop valid estimates of potential non-use benefits for I&E reductions at IPEC. The existing biological information suggests that non-use benefits are not likely to be significant for the CWWS or Cooling Tower alternatives based on criteria from the economics literature. Moreover, non-use benefits can only be estimated through stated preference surveys, which are difficult and costly to implement and can produce unreliable results. Since non-use benefits are not likely to be significant for the CWWS or Cooling Tower alternatives and studies to estimate non-use benefits are difficult and costly to implement, we do not attempt to monetize potential non-use benefits. Instead, we develop qualitative assessments of their potential significance, an approach that is consistent with EPA guidance in various 316(b) rulemakings, as discussed in Appendix E.

a. Market Direct Use Benefits

Direct use market benefits consist of the gains in primary products that are bought and sold as factors of production or final consumption products. Increases in the fish caught by commercial fishermen and sold in fish markets constitute market benefits. We therefore include commercial fishing benefits in our analysis. The other market benefits mentioned in the EPA's 316(b) analysis documents and included in the EPA *Guidelines* are either included in the commercial fishing benefits or are evaluated qualitatively in Chapter V. We did not quantify these other potential market benefits because they are inapplicable to this case or our qualitative assessment found them unlikely to be significant.

b. Non-market Direct Use Benefits

As the EPA *Guidelines* note, individuals can benefit from improvements in recreational opportunities due to environmental improvements. Unlike the market benefits described above, however, these benefits have no explicit market value. The EPA 2000 *Guidelines* distinguish between two subcategories of non-market benefits for consideration in benefit-cost analysis:

1. Consumptive uses, such as recreational fishing and hunting in which the catch is kept; and

2. Non-consumptive uses, such as catch-and-release fishing, wildlife viewing or boating (EPA 2000, p. 70).

Increases in the numbers of adult fish that are valued by recreational anglers would yield recreational benefits as a result of increased harvests. Thus, the consumptive use of recreationally caught fish is relevant for this benefit evaluation. Moreover, fish that are caught but released also yield recreational benefits, in this case non-consumptive, non-market, direct benefits.

The other non-market benefits mentioned in the EPA's 316(b) support documents and included in the EPA *Guidelines* are either included in the recreational fishing benefits or are evaluated qualitatively in Chapter V. As with the other market benefit categories, we did not quantify these other potential non-market benefits because either they are inapplicable to this case or our qualitative assessment found them unlikely to be significant.

c. Indirect Use Benefits

As noted above, species without direct commercial or recreational value have indirect effects on species with direct use value. In particular, increases in forage fish species and in un-harvested game fish serve as additional food sources for valuable species.

ASAAC (2013) developed estimates of the additional recreational and commercial harvest due to increases in forage fish due to CWWS and Cooling Towers. The estimates include the assumption that all of the forage fish gains in mass would be converted to striped bass (ASAAC 2013). This approach would overestimate the potential benefits to the extent that the gains in forage fish lead to gains for species that are less highly valued by commercial and recreational anglers. We include the additional striped bass biomass from additional forage fish in the commercial and recreational catch estimates, in addition to the direct changes in the biomass of species of commercial or recreational value.

Changes in fish populations in theory could have other indirect use benefits (beyond the increases in harvested game fish due to additional forage fish and un-harvested game fish). Appendix F provides assessments of the various potential categories and Chapter V provides a summary of these assessments. We conclude that these potential benefit categories are not likely to be significant.

d. Summary of Benefit Categories to be Quantified

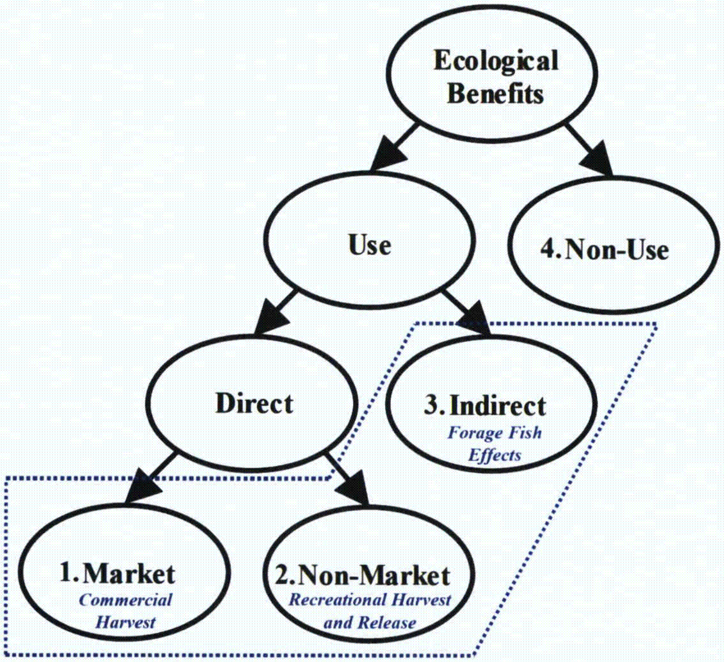
The framework developed by economists to evaluate the benefits from ecological improvements provides a means of identifying the relevant benefit categories for CWWS and Cooling Towers. Based on this framework and assessment of the relevant benefit categories, we monetize three types of benefits, as shown in Figure 3.

1. Commercial fishing benefits (market direct use benefits);

2. Recreational fishing benefits (non-market direct use benefits); and

3. Forage fish benefits (indirect use benefits).

As noted above, we do not monetize non-use benefits, as we do not expect the non-use benefits from CWWS or Cooling Towers to be significant and developing monetary values would be difficult and costly. Our assessment of potential non-use benefits is discussed in more detail in Appendix E.



Source: Adapted from EPA (2000, p. 70); see also EPA (2010, p. 7-9)

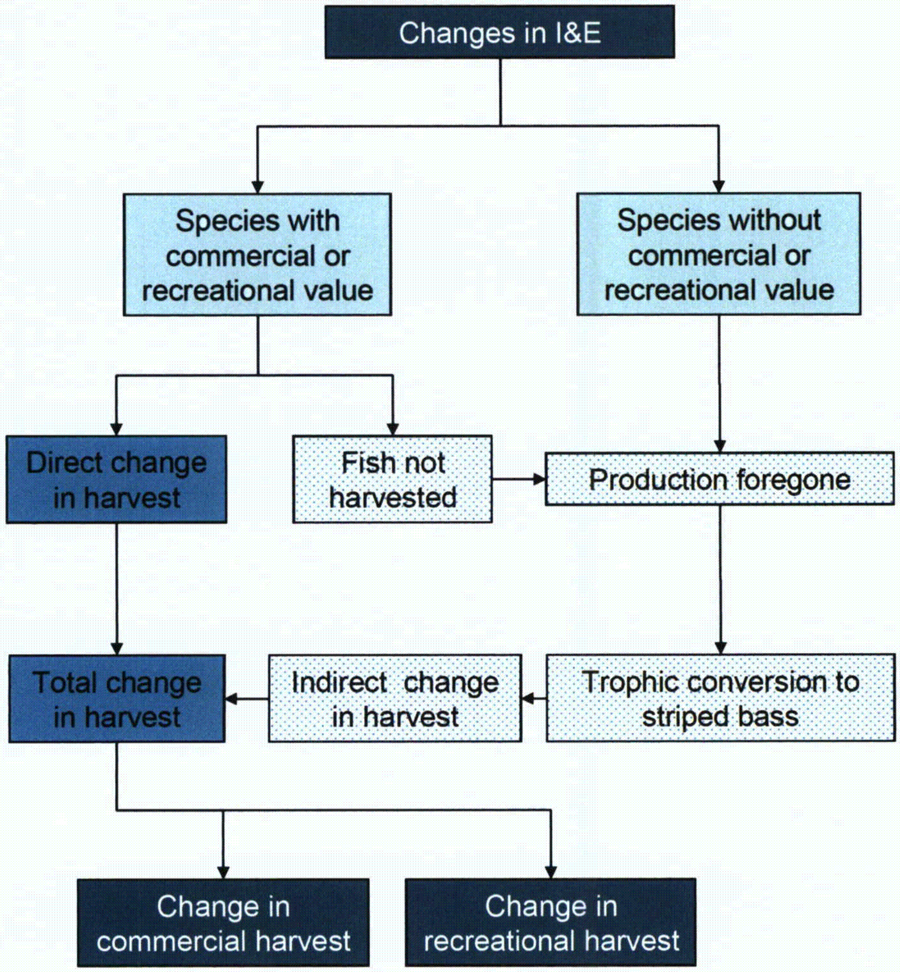
Figure 3. Summary of Benefit Classification Scheme from EPA 2000 *Guidelines* with Monetized Benefits Highlighted and Identified

B. Theoretical Fish Harvest Gains

The monetized benefits of I&E reductions are based on theoretical increases in the commercial and recreational harvests of different species. Although the biological estimates relate to commercial and recreational harvests—i.e., fish caught and kept, thus removing them from the population—our estimates of the value of recreational catch account for the fact that recreational anglers also derive benefits from fish that they catch but release.

1. Overview of Methodology for Biological Harvest Estimates

Figure 4 summarizes the steps we understand ASAAC (2013) followed in estimating theoretical gains in commercial and recreational harvest for a given species due to changes in I&E. Based on monitoring data from the Hudson and IPEC, ASAAC estimated I&E by life stage and species for several cases, including the current configuration, CWWS and Cooling Towers.



Source: Adapted from ASAAC (2013)

Figure 4. Summary of Steps in Estimating Changes in Commercial and Recreational Harvests

For entrainment, the organisms affected are eggs and larvae. For impingement, the organisms affected are primarily small adult fish and juveniles of larger fish species. The number of organisms potentially lost due to I&E can appear to be quite large, measured in the millions. However, most of those organisms are eggs or larvae, and very few of them would survive to adulthood even absent I&E. In general, most eggs do not survive to the larval stage, most larvae do not survive to become juveniles, and most juveniles do not reach adulthood. For each species and life stage affected, ASAAC (2013) estimates total production forgone (the estimated weight of biomass that the organisms lost to I&E mortality would have produced through their remaining life) based on survival rates and average weights of species at various life stages.

The next step in the biological assessment is to estimate how changes in production foregone would affect harvests. For species that are valued commercially or recreationally, ASAAC estimates the direct change in harvest due to I&E at IPEC. For species without commercial or recreational value ("forage" species) and for uncaught individual fish of valued species, ASAAC estimates the theoretical indirect change in harvest for valued predator species by assuming that the production forgone would have been consumed by the predator species and converted to predator species biomass, which would then be subject to harvest. As noted above, ASAAC assumes that all of this indirect increase would be in the form of striped bass. The sum of direct and indirect changes in harvest is the estimated total change in harvest. The total harvest is divided between commercial and recreational anglers, as discussed below.[16]

2. Categorization of Species

Table 11 lists the species for which ASAAC (2013) modeled theoretical annual losses due to I&E at IPEC under various circumstances. For two of these species—bay anchovy and Atlantic tomcod—ASAAC estimated only theoretical annual losses in production foregone, because these species are prey for larger species and are not harvested to any significant degree by commercial or recreational anglers. In the benefit analysis, those species are not counted directly, but are counted indirectly as they can increase the mass of other fish caught. As noted above, ASAAC assumed that all of the indirect gains would be for striped bass. The other species in Table 11—*Alosa* sp. (alewife and blueback herring, often collectively referred to as river herring), American shad, white perch, and striped bass—are harvested species for which ASAAC estimated theoretical annual losses in harvest. ASAAC also estimated theoretical indirect effects for I&E changes for these harvested species (translated into changes in annual harvest for striped bass) because some individuals of the harvested species would be eaten by other fish rather than harvested.[17]

Table 11. Modeled Species Categories

Species	Category
Bay anchovy	Forage only
Atlantic tomcod	Forage only
Alosa sp.	Harvested
American shad	Harvested
White perch	Harvested
Striped bass	Harvested

Source: ASAAC (2013)

3. Annual Theoretical Gains in Harvest

This section provides information on ASAAC's (2013) estimates of annual theoretical harvest losses under the regulatory baseline, the current configuration, CWWS and Cooling Towers. Although for convenience we report only totals for modeled species in this section, the estimates from ASAAC are by individual species, and we use the estimates by individual species in the benefit calculations.

[16] The increases in fish harvests are assumed to begin immediately upon installation of CWWS or Cooling Towers. Incorporating a lag between installation of CWWS or Cooling Towers and increased harvests to reflect growth of eggs, larvae, and juvenile fish into harvestable adult fish would decrease the present value of potential benefits.

[17] Other species beyond the modeled species are addressed in the valuation section of this chapter.

Table 12 shows estimates of theoretical annual fishery harvest losses due to I&E under the various CWIS configurations. The estimates reflect average operation conditions for IPEC. Note that these estimates include forage species insofar as they indirectly contribute to harvests for striped bass. The total harvest losses decline substantially from the regulatory baseline to the current configuration and the CWIS alternatives. The annual harvest losses for Cooling Towers are only slightly lower than annual losses for the current configuration, and they are much larger than the annual losses for CWWS. As explained in ENERCON (2010a), the relatively large losses with Cooling Towers reflect the presumption that they can only be operated on average about 13 percent of the year (with monthly variation).

Table 12. Estimated Annual Fishery Harvest Losses Due to I&E at IPEC (kg)

	Impingement	Entrainment	Total
Regulatory Baseline	29,600	238,933	268,533
Current Configuration	1,807	98,754	100,561
CWWS	69	13,040	13,109
Cooling Towers	1,681	91,203	92,884

Source: ASAAC (2013)

Table 13 uses the estimated annual theoretical losses to calculate the theoretical gains for CWWS and Cooling Towers relative to the current configuration. To provide a sense of perspective, Table 13 also shows the theoretical annual gains for the current configuration relative to the regulatory baseline. As shown in the table, the estimated average annual theoretical total fishery harvest gains due to CWWS is 87,452 kg, and the estimated average annual theoretical total harvest gains due to Cooling Towers is only 7,677 kg. Note that these annual results reflect values when the two technologies are in place and do not reflect the fact that CWWS would be operational several years in advance of Cooling Towers.

Table 13. Estimated Annual Fishery Harvest Gains Relative to the Current Configuration (kg)

	Impingement	Entrainment	Total
Current Configuration*	27,793	140,179	167,972
CWWS	1,738	85,714	87,452
Cooling Towers	126	7,551	7,677

Source: NERA calculations as explained in text
* Current Configuration harvest gains are relative to the regulatory baseline

4. Gains by Species and Commercial vs. Recreational Harvest

To develop information on the value that households place on additional harvest, it is necessary to determine theoretical harvest gains by species and to divide additional harvest between commercial and recreational harvest. The social values differ by species, and for each species the social values differ by commercial and recreational harvest. Appendix B describes our methodology and data for allocating increased harvests between commercial and recreational anglers.

Table 14 shows our estimates of theoretical annual harvest gains by modeled species for CWWS and Cooling Towers (relative to the current configuration). The first two rows show total gains by species changes in annual harvest for CWWS and Cooling Towers. Note that striped bass account for more than 98 percent of the increased harvest among the species evaluated. The next rows show the percentage of the harvest that is estimated to be taken by commercial fishermen. Those commercial shares are then used in the next two sections to divide the total harvest gains into commercial and recreational components.

Of the total change in harvest, commercial fisheries account for about 11 percent of the total mass (based overwhelmingly on the commercial share for striped bass). The last section in the table reports the recreational gains in terms of numbers of adult harvestable fish, because most of the literature valuing increased recreational catches has measured catch in terms of number of fish, not weight.

Table 14. Estimated Annual Harvest Gains Due to CWWS and Cooling Towers by Species and Commercial/Recreational

	Alosa sp	American shad	White perch	Striped bass	Total
Total Gains (kg)					
CWWS	127	15	85	87,226	87,452
Cooling Towers	10	1	8	7,657	7,677
Commercial Share	98%	99%	60%	10%	10%
Commercial Gains (kg)					
CWWS	124	15	51	8,860	9,050
Cooling Towers	10	1	5	778	794
Recreational Share	2%	1%	40%	90%	90%
Recreational Gains (kg)					
CWWS	2	0	34	78,366	78,402
Cooling Towers	0	0	3	6,880	6,883
Recreational Gains (fish)					
CWWS	12	0	241	23,641	23,894
Cooling Towers	1	0	23	2,075	2,099

Source: NERA calculations as explained in text

C. Valuation of Theoretical Commercial Harvest Gains

Following standard economic methodology, we estimate the social benefit of an extra kg of fish based upon the increase in producer surplus, which measures the increase in revenues to fishermen minus the additional costs they incur. Revenues are based on *ex-vessel* market prices, i.e. the prices that fishermen receive at the dock for their catch, for that species.[18]

1. *Ex Vessel* Prices per Pound of Commercial Harvest

To estimate the market price for each species caught commercially, we use annual averages of *ex-vessel* prices calculated from data reported by the National Marine Fisheries Service (NMFS). As described in more detail in Appendix C, we obtained NMFS data on landings and total *ex-vessel* revenues, by species, for the 10-year period 2003-2012. We then calculated a weighted average price (in 2012 dollars) for each species over the 10-year period. As described in Appendix C, we also evaluated historical trends in commercial prices and concluded that future commercial prices may not be as high in real terms as the historical averages we use. Table 15 shows the estimated commercial prices for the four species with commercial harvests. Striped bass, which accounts for most of the theoretical fish gains, is also the most commercially valuable species with an estimated *ex-vessel* price of $6.15 per kg.

Table 15. Commercial Prices (2012$/kg)

Striped Bass	White Perch	American Shad	Alosa sp.
$6.15	$1.70	$2.05	$0.54

Source: National Marine Fisheries Service and NERA calculations as explained in Appendix C

2. Estimates of Producer Surplus per Pound of Commercial Harvest

As noted above, the net gain to commercial fishermen (as measured by change in producer surplus) depends upon the additional costs, as well as the additional revenues. EPA notes in its analysis document for the proposed Replacement Rule that the additional costs are generally proportional to the additional revenues from larger harvests (EPA 2011, Chapter 6-3). Thus, the net gain to commercial fisherman (change in producer surplus) can be estimated as a percentage of the change in gross revenue. EPA developed estimates of this percentage (based on incremental analysis to reflect increased harvest due to the 316(b) policy) for each harvested fish species in each region of the country.

Table 16 shows EPA's estimates of change in producer surplus as a percentage of the change in gross revenue for the relevant species for this analysis in the Mid-Atlantic region. We used these percentages to calculate the commercial benefits of reduced I&E at IPEC based on the theoretical increase in gross revenue. Additional information on these percentages is provided in Appendix C.

[18] Additional revenues at other points of the distribution chain, including sale to consumers in food stores and restaurants, do not represent net social benefits, because the additional revenues would be fully offset by higher costs (assuming competitive markets).

Table 16. Producer Surplus as a Percentage of Gross Revenue, by Species

Striped Bass	White Perch	American Shad	Alosa sp.
67%	82%	84%	85%

Source: EPA (2011, p. 6-7)

3. Complications Related to "The Tragedy of the Commons"

Using these estimates of producers' surplus to measure the societal value of increased commercial catch may overstate commercial benefits because the calculations ignore the potential effects of the common-property characteristics of open-access fisheries. As discussed in Appendix C, open-access creates a situation referred to as "the tragedy of the commons." In such cases, if the fish stock increases and fishermen make a profit above competitive returns, the level of effort would expand (e.g., through the entry of new boats and crews or more intensive use of existing resources) in response to the increased profits so that costs would rise, potentially to the point where the potential gains in producers' surplus are eliminated. As a result, under the assumption of an open-access fishery, the long-term net gains to fishermen of additional catch would be zero because any short-term gains would be offset by the costs of the additional fishing effort these short-term gains encourage. We discuss this complication in Appendix C.

4. Accounting for Non-Modeled Species

ASAAC (2013) notes that the modeled species listed above in Table 11 account for the vast majority of organisms lost at IPEC due to I&E. To account for losses of other species beyond the modeled species, ASAAC (2013) indicates that biological benefit results should be scaled up by 1.05 to account for the species that were not modeled.

We accounted for the non-modeled species by scaling our monetized commercial benefit estimates up by this same factor, 1.05. This calculation is equivalent to assuming that the biological commercial gains were equivalent to those for the modeled species and that the average commercial value is the same as for the modeled species. These assumptions are likely to overstate benefits to the extent that the non-modeled species are (1) less likely to be harvested commercially than the modeled species and (b) likely to have lower commercial values than the modeled species. Both conditions seem likely.

5. Present Values of Commercial Benefits

Projected commercial benefits in any given year are calculated by multiplying the gain in commercial harvest in kg for each species by the additional producers' surplus per kg of that species, and then increasing the total to reflect non-modeled species as noted above. Table 17 shows estimates of the present values of commercial benefits for CWWS and Cooling Towers relative to current conditions. As with the cost results, we show benefit results based on real annual discount rates of 3 and 7 percent. Relative to the current configuration, the estimated present values of commercial benefits for CWWS are $0.3 million based on a discount rate of 3 percent and $0.1 million based on a discount rate of 7 percent. For Cooling Towers, the estimated present values of commercial benefits relative to the current configuration are $0.03

million based on a discount rate of 3 percent and $0.01 million based on a discount rate of 7 percent.

Table 17. Present Values of Commercial Fishing Benefits (2012$millions)

	Discount Rate	
Technology	**3%**	**7%**
CWWS	$0.3	$0.1
Cooling Towers	$0.03	$0.01

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars.
Source: NERA calculations as explained in text

D. Valuation of Theoretical Recreational Harvest Gains

This section considers the theoretical benefits to recreational fishermen from implementation of CWWS or Cooling Towers at IPEC.

1. Valuation of Additional Recreational Harvest

We developed a detailed statistical analysis to estimate the value that recreational anglers place on additional harvest, where the value is measured by the increase in consumers' surplus (i.e., consumers' willingness to pay for the additional harvest). Our statistical analysis is referred to as a "meta-analysis" because it combines the results from various individual studies (EPA 2010). The meta-analysis developed here, which is described in detail in Appendix D, estimates a relationship between the marginal value that recreational anglers place on an additional fish caught and the catch rate per trip.

As discussed in Appendix D, it is important to account for the fact that recreational anglers often release some of the fish they catch. The harvest value estimates can be modified to reflect the additional value of fish that are caught and released. As discussed in Appendix D, in New York waters, for every fish harvested, on average approximately 2.1 fish are caught and released; thus, the total number of fish caught recreationally is almost 3.1 times higher than the number harvested. Our estimates of the value per fish harvested account for this additional catch.

Our meta-analysis yields an estimate of about $67 per fish harvested (2012 dollars); at the average ratio of 3.1 striped bass caught per fish harvested, this figure would imply an average value of about $22 per fish caught. This value is based on estimates for striped bass (which are the dominant species in our estimates) or for small game fish (which include striped bass) along the Atlantic coast. The value we use is substantially higher than the value of about $8 per fish caught (2012 dollars) derived from EPA's meta-analysis performed as part of its 2011 benefit-cost case study. Although striped bass generally are more highly valued than the other modeled species potentially affected by I&E at IPEC, we applied that same value to other fish caught by recreational anglers. This approach overstates recreational benefits to the extent that the other modeled species are less highly valued by recreational anglers.

2. Accounting for Non-Modeled Species

As noted above, ASAAC (2013) indicates that biological benefit results should be scaled up by 1.05 to account for the species that were not modeled. As with the commercial benefit estimates, we accounted for the non-modeled species by scaling our monetized recreational benefit estimates up by this same factor, 1.05. This calculation is equivalent to assuming that the biological recreational gains were equivalent to those for the modeled species and that the average recreational value is the same as for the modeled species. These assumptions are likely to overstate benefits to the extent that the non-modeled species are (1) less likely to be harvested recreationally than the modeled species and (b) likely to have lower recreational values than the modeled species (which assumes the use of the highly-valued striped bass). Both conditions seem likely.

3. Present Values of Recreational Benefits

We calculate the annual recreational benefits of CWWS and Cooling Towers as the increase in number of fish harvested recreationally multiplied by the marginal recreational harvest value per fish, increased to reflect the additional value of non-modeled species as explained above. Present values for CWWS and Cooling Towers are based on aggregating annual benefits through 2033 and 2035 for Units 2 and 3.

Table 18 shows the present values of estimated recreational benefit estimates for CWWS and Cooling Towers. Relative to the current configuration, the estimated present values of recreational benefits from CWWS are $11.1 million based on a discount rate of 3 percent and $6 million based on a discount rate of 7 percent. For Cooling Towers, the estimated recreational benefits are $1.2 million and $0.6 million based on discount rates of 3 and 7 percent.

Table 18. Present Values of Recreational Fishing Benefits (2012$millions)

	Discount Rate	
Technology	**3%**	**7%**
CWWS	$11.1	$6.0
Cooling Towers	$1.2	$0.6

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars.
Source: NERA calculations as explained in text

E. Total Quantified Theoretical Benefits

Table 19 shows estimated present values of total quantified theoretical benefits for CWWS and Cooling Towers (i.e. recreational and commercial). At a discount rate of 3 percent, estimated total theoretical benefits are $11.3 million for CWWS and $1.2 million for Cooling Towers. With a higher discount rate of 7 percent, the theoretical benefits are $6.1 million for CWWS and $0.6 million for Cooling Towers.

Table 19. Total Estimated Benefits of Fish-Protection Alternatives (2012$ millions)

	Discount Rate	
Technology	**3%**	**7%**
CWWS	$11.3	$6.1
Cooling Towers	$1.2	$0.6

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars.
Source: NERA calculations as explained in text

V. Net Benefits/Costs of Cylindrical Wedgewire Screens and Cooling Towers

This chapter uses the cost and benefit results from the prior chapters to develop information on the net benefits (i.e., benefits minus costs) of CWWS and Cooling Towers. We also consider the implications of key assumptions underlying the results and assess the likely significance of omitted benefit and cost categories. The next chapter provides formal tests of the sensitivity of the results to various uncertainties in costs and benefits.

A. Net Benefits/Costs

1. Rationale for Using Net Benefits/Costs to Evaluate CWWS and Cooling Towers

It is well accepted among economists and policy analysts that net benefits—i.e., benefits minus costs—is the preferred measure for public decision making. In general, a project should not be undertaken unless it is expected to yield positive net benefits. That is because the alternative of doing nothing (which in this case represents continuing to operate the current configuration at IPEC) has, by definition, zero benefits and costs and hence zero net benefits. Thus, the alternative of doing nothing is preferable to an alternative action with negative net benefits. Note that this decision rule assumes that all significant costs and benefits have been quantified. We discuss non-quantified benefits and costs, including their likely significance for overall results, below in this chapter.

Analysts also sometimes calculate benefit-cost ratios (benefits divided by costs), but these are generally less useful than net benefits for decision-making. The U.S. Office of Management and Budget states:

> The size of net benefits, the absolute difference between the projected benefits and costs, indicates whether one policy is more efficient than another. The ratio of benefits to costs is not a meaningful indicator of net benefits and should not be used for that purpose. It is well known that considering such ratios alone can yield misleading results (OMB 2003, p. 10).

A well-known text on benefit-cost analysis notes a problem with comparing projects with different scales on the basis of benefit-cost ratios and recommends net benefits as the appropriate criterion for choosing among alternative projects:

> Benefit-cost ratios can sometimes confuse the choice process when the projects under consideration are of different scale....we recommend that analysts avoid using benefit-cost ratios and rely instead on net benefits to rank policies (Boardman et al. 2011, p. 34).

2. Net Benefits/Costs Results

Table 20 summarizes the present values of benefits, costs and net benefits of CWWS and Cooling Towers. As noted in prior chapters, the costs and benefits are measured relative to current operations. Results are presented for the two discount rates (3 percent and 7 percent). There are two principal conclusions from these results:

1. Costs exceed benefits for both CWWS and Cooling Towers using both discount rates (and thus for convenience we report net costs rather than net benefits); and

2. Cooling Towers have higher costs and lower benefits than CWWS using both discount rates.

Table 20. Present Values of Estimated Costs, Benefits, and Net Costs for CWWS and Cooling Towers ($millions)

	Discount Rate	
Technology	3%	7%
CWWS		
Costs	$169.5	$123.8
Benefits	$11.3	$6.1
Net Costs	$158.2	$117.7
Cooling Towers		
Costs	$1,056.6	$670.9
Benefits	$1.2	$0.6
Net Costs	$1,055.4	$670.2

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars.
Net costs may differ slightly from costs minus benefits because of rounding.
Source: NERA calculations as explained in text

The net costs for both technologies are substantial, but the net costs are considerably greater for Cooling Towers. For CWWS, the net costs range from about $117.7 million to about $158.2 million using the two discount rates. For Cooling Towers, the net costs range from about $670.2 million to about $1.1 billion using the two discount rates.

Table 21 shows the *differences* in costs and benefits between CWWS and Cooling Towers. The comparisons are quite dramatic. Cooling Towers have much higher costs than CWWS, with the difference equal to either about $547 million or $887 million depending on the discount rate. In contrast, CWWS has substantially greater benefits than Cooling Towers, with the difference equal to either about $5.5 million or about $10.1 million depending on the discount rate.

Table 21. Comparisons of Costs and Benefits of CWWS and Cooling Towers ($million)

Technology	Discount Rate 3%	7%
Costs		
CWWS	$169.5	$123.8
Cooling Towers	$1,056.6	$670.9
Difference	+$887.1	+$547.0
Benefits		
CWWS	$11.3	$6.1
Cooling Towers	$1.2	$0.6
Difference	-$10.1	-$5.5

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. Differences may differ slightly from Cooling Tower values minus CWWS values because of rounding.
Source: NERA calculations as explained in text

Because CWWS yield *greater* benefits at substantially *smaller* costs than Cooling Towers, we can conclude from the results in Table 21 that Cooling Towers are "dominated" by the CWWS. Assuming there are no offsetting considerations, a rational decision maker would not choose a dominated alternative.[19]

B. Implications of Assumptions Underlying Quantified Benefits and Costs

In accordance with conducting a comprehensive benefit-cost analysis, we assess various factors that would have the potential to change the two conclusions reached above regarding the net costs of CWWS and Cooling Towers and the dominance of CWWS relative to Cooling Towers. In this section we consider the assumptions underlying the quantified costs and benefits. In the following section, we consider the potential significance of effects that were not quantified.

1. Assumptions Regarding Quantified Benefits

The quantified benefits analyses incorporate various assumptions that are likely to overstate the benefits. This section summarizes these assumptions.

a. Empirical Evidence of No Measurable Harvest Impacts

As discussed in ASAAC (2013), empirical analyses of historical data for the Hudson River (including Barnthouse et al. 2008 and Barnthouse et al. 2010) indicate that reducing losses of eggs, larvae, and juvenile fish due to I&E at IPEC would not result in larger populations or

[19] The economic term "dominant" or "dominate," most commonly used to describe strategies in game theory, conveys that a choice is inferior to an alternative by every relevant criterion. Boardman et al. (2011, p. 469) explains its use in cost-benefit analysis: "One alternative can dominate another even if they have neither the same cost nor the same effectiveness, as long as it is superior on both dimensions. Clearly, dominated alternatives should not be selected."

harvests of adult fish. Thus, there may be no benefits for CWWS or Cooling Towers in terms of commercial or recreational harvests. As noted, our estimates of theoretical benefits are based upon theoretical calculations by ASAAC (2013).

b. Fishery Restrictions That Could Lower Commercial Fishing Benefits

As discussed in Appendix B, New York and other states along the Atlantic coast have imposed various restrictions on commercial and recreational fishing of striped bass and other modeled species. ASAAC (2013) estimated changes in fishery harvests using standard fishing mortality parameters without accounting for these restrictions. Reducing the harvest impacts to account for the fishery restrictions could reduce the theoretical benefits of CWWS and Cooling Towers.

c. Attributing All Indirect Benefits to the Highest Value Species (Striped Bass)

We have assumed that all additional forage fish and other forms of production forgone would be consumed by striped bass, a species with relatively high commercial and recreational values. Accounting for consumption by other species instead of striped bass would reduce the theoretical benefits.

d. Valuing Non-Modeled Species at the Value of the Modeled Species

ASAAC (2013) includes data on I&E for species that are not modeled. That is, ASAAC does not develop estimates of the marginal harvest due to these "other species" since it does not have the information to do the calculations. The I&E data indicate that these other species represent an additional 5 percent of the I&E. We increase our estimates of benefits for both CWWS and Cooling Towers by 5 percent, which implies that these other species would translate into additional harvest with value equal to the modeled species. This assumption is likely to substantially inflate the value of the "other species," since they are not likely to have values as great as striped bass, which accounts for the vast majority of the quantified benefits.

e. No Lag between Reducing I&E and Harvesting Additional Adult Fish

The increases in fish harvests are assumed to begin immediately upon installation of CWWS and Cooling Towers. Incorporating a lag between installation of CWWS and Cooling Towers and increased harvests to reflect growth of eggs, larvae, and juvenile fish into harvestable adult fish would decrease the present value of theoretical benefits because benefits would occur farther in the future and be discounted accordingly. Our assumption of immediate harvest increases, then, likely leads us to overstate theoretical benefits.

2. Assumptions Underlying the Cost Estimates

The quantified cost analyses include various assumptions regarding costs, all of which would tend to understate the costs. Some of the assumptions relate to both CWWS and Cooling Towers, while others relate only to one of the two technologies.

a. No Costs for Construction Design and Permitting

We have excluded costs related to construction design and planning for both technologies in order to provide comparable estimates for the two technologies. As noted in Chapter III, Tetra Tech (2013) does not provide costs for designing and permitting Cooling Towers. Thus, to avoid biasing the comparison of costs, design and permit costs are also not included for CWWS. This assumption understates the costs for both CWWS and Cooling Towers.

b. No Costs for Construction Contingencies

We also have excluded costs related to potential cost contingencies. As noted in Chapter III, ENERCON (2013a) does not provide information on possible contingencies for CWWS (although a range of uncertainty underlying the capital cost estimate is included, as discussed in Chapter VI). Thus, to avoid biasing the comparison of costs, we have excluded contingency costs for Cooling Towers. This assumption understates the costs for both CWWS and Cooling Towers.

c. Not All Costs are Included for Possible Air Burst System for CWWS

As noted in Chapter III, the costs developed by ENERCON for the CWWS include do not include certain components of an air-burst system that might be installed at a later date. After acquiring operating experience, it will be decided whether additional elements are required for satisfactory operation of the CWWS system (ENERCON 2013a). Thus, our estimate would understate the costs of CWWS if additional elements ultimately were required.

d. No O&M Costs for CWWS

As noted in Chapter III, ENERCON has not developed estimates of the possible O&M costs for CWWS. Thus, our cost estimate will underestimate the potential costs of CWWS. We do not expect such costs to be significant or to undermine our basic conclusions.

3. Summary

The factors above represent assumptions that have the potential to affect our estimates of quantified costs and benefits as well as assessments of the value that individuals place on additional harvest. This information on our assumptions suggests the following implications for our two principle conclusions:

1. *Conclusion is reinforced that costs are much greater than benefits for both CWWS and Cooling Towers.* Accounting for these factors would tend to reduce benefits and increase costs. Thus, our conclusion that costs are much greater than benefits for both CWWS and Cooling Towers is reinforced by consideration of these factors.

2. *Conclusion is robust that Cooling Towers dominated by CWWS.* The benefits factors would tend to have the same proportional effect for CWWS and Cooling Towers and thus would not affect their relative size substantially. The omitted cost components may be different for the two technologies, but given the large quantified cost difference, we would not expect any

adjustments in the cost factors to affect the relative costs of the two technologies substantially. Thus, our conclusion regarding the dominance of CWWS over Cooling Towers is robust with respect to these omitted factors.

C. Implications of Non-quantified Costs and Benefits

1. Importance of Considering the Implications of Non-Monetized Costs and Benefits

The basic framework presented above includes clarifying the relevant alternatives (CWWS and Cooling Towers), determining the potential effects, valuing the positive effects (benefits) and negative effects (costs) to the extent feasible in dollar terms, and calculating the net costs or net benefits. It is also important to consider the potential effects that are not monetized. Both EPA and OMB recommend qualitatively describing the effects and implications of omitting these factors when presenting the overall results. EPA notes:

> Benefits and costs should be reported in monetary terms whenever possible. In reality, however, there are often effects that cannot be monetized, and the analysis needs to communicate the full richness of benefit and cost information beyond what can be put in dollar terms. Benefits and costs that cannot be monetized should, if possible, be quantified... Benefits and costs that cannot be quantified should be presented qualitatively (e.g., directional impacts on relevant variables) (EPA 2010, p. 11-2).

Similarly, OMB states:

> A complete regulatory analysis includes a discussion of non-quantified as well as quantified benefits and costs. A non-quantified outcome is a benefit or cost that has not been quantified or monetized in the analysis. When there are important non-monetary values at stake, you should also identify them in your analysis so policymakers can compare them with the monetary benefits and costs. When your analysis is complete, you should present a summary of the benefit and cost estimates for each alternative, including the qualitative and non-monetized factors affected by the rule, so that readers can evaluate them (OMB 2003, p. 3).

In this section we provide a qualitative discussion and assessment of non-quantified costs and benefits, including conclusions regarding their likely significance for the overall results.

2. Qualitative Assessments of Non-quantified Benefits

As noted in Chapter IV, our benefits assessment uses the benefit categories described by EPA (2010). We developed monetary benefit estimates for three categories of benefits: (1) market direct use benefits (based on commercial fishing impacts); (2) non-market direct use benefits (based on recreational fishing impacts); and (3) indirect use benefits (focusing on food chain effects, i.e. fish that contribute to forage, which were included in estimates of commercial and recreational fishing impacts). We determined that only these three benefit categories are likely to be significant for the cost-benefit comparisons of CWWS and Cooling Towers at IPEC.

EPA (2011) includes a list of benefit categories that may be relevant to cooling water intake analyses (p. 4-3). We assessed the other benefit categories in this list (other than commercial fishing impacts, recreational fishing impacts, and food chain effects, i.e. fish that contribute to forage) and determined that none are likely to be significant influences on the cost-benefit comparisons of CWWS and Cooling Towers at IPEC.

Table 22 provides a summary of our conclusions regarding the other categories identified by EPA in its analysis for its proposed Replacement Rule (EPA 2011, p. 4-3). The following subsections provide information on our assessments of these other benefit categories.

Table 22. Summary Assessment of Benefit Categories in EPA Proposed 316(b) Replacement Rule

Benefit Categories	Quantified?	Notes
Market Direct Use		
Increased commercial landings	Yes	Includes indirect food chain effects (forage)
Non-market Direct Use		
Improved value of recreational fishing	Yes	Includes indirect food chain effects (forage)
Improved value of subsistence fishing	Yes	Included in total recreational benefits
Increase in recreational fishing participation	No	Assessed and determined not likely to be significant
Indirect Use		
Food chain effects (fish contributing to forage)*	Yes	Included in commercial and recreational benefits
Increased equipment sales, rental, and repair	No	Assessed and determined not likely to be significant
Increased bait and tackle sales	No	Assessed and determined not likely to be significant
Increased consumer market choices	No	Assessed and determined not likely to be significant
Increased choices in restaurant meals	No	Assessed and determined not likely to be significant
Increased property values near water	No	Assessed and determined not likely to be significant
Increased ecotourism	No	Assessed and determined not likely to be significant
Increased value of aquatic recreational experience	No	Assessed and determined not likely to be significant
Increase in aquatic recreational participation	No	Assessed and determined not likely to be significant
Non-use	No	Assessed and determined not likely to be significant

Note: (*) "Food chain effects (fish contributing to forage)" category is not listed in EPA 2011 (p. 4-3) but it is mentioned in EPA's discussion of indirect benefits (p. 4-2); it is included here for clarity.

Source: Categories based on EPA 2011 (p. 4-3); other information based on NERA analysis as explained in text

a. Market Direct Use Benefits

EPA (2011) includes only one category of market direct use benefits: "increased commercial landings." This category is included in our quantified benefit estimates. Note that our benefit estimates include indirect food chain effects (i.e., fish that contribute to forage) as discussed in Chapter IV.

b. Non-market Direct Use Benefits

Our quantified benefit estimates include the first category that EPA (2011) lists for non-market direct use benefits: "improved value of recreational fishing due to increased catch." Note that our benefit estimates include indirect food chain effects (i.e., fish that contribute to forage) as discussed in Chapter IV.

The second category that EPA (2011) lists for non-market direct use benefits is "improved value of subsistence fishing." We understand that the additional catch in this benefit category is included in our quantified benefit estimates for recreational fishing, because the harvest information from NMFS (used to allocate the theoretical harvest increase to commercial and recreational fisheries) does not distinguish subsistence anglers from recreational anglers. Although the value that subsistence anglers place on additional fish harvest may differ from other anglers, we would not expect the differences to have a significant effect on the benefit estimates because subsistence anglers are likely to be a small fraction of the total. Note that EPA (2011) did not quantify subsistence fishery impacts separately for its proposed Replacement Rule (p. 4-3).

The third category that EPA (2011) lists for non-market direct use benefits is "increase in recreational fishing participation." This potential benefit category relates to the potential increase in the number of people who would fish recreationally as a result of the reductions in I&E due to CWWS or Cooling Towers. We do not have data to develop such estimates but we expect them to be small because of the small effects of reduced I&E on overall harvest/catch rates of striped bass, the species accounting for the vast majority of gains. Thus, we conclude that this benefit category is not likely to be significant for cost-benefit comparisons of CWWS or Cooling Towers at IPEC. EPA (2011) also did not quantify this category of impact, citing data constraints.

c. Indirect Use Benefits

Indirect use benefits include the contribution of food chain effects (i.e., forage) to commercial and recreational fishing benefits. EPA (2011, p. 4-3) lists other potential indirect benefit categories and organizes them into market goods and non-market goods. In Table 22, we combine the indirect benefit categories into a single list. Appendix F provides an analysis of the nature of these potential benefit categories and assessments for each of the categories presented in Table 22. We conclude that apart from forage fish effects, no potential indirect use benefit from CWWS or Cooling Towers is likely to be significant. EPA (2011) also did not quantify any of these other indirect use benefits, citing data constraints.

d. Non-use Benefits

Appendix E provides our assessment of potential non-use benefits from CWWS and Cooling Towers at IPEC. We conclude that it is not appropriate to develop monetary values here and thus we do not develop monetary values. We conclude that any potential non-use benefits are not likely to be significant based upon the criteria for significance that have been developed in the economic literature.

3. Qualitative Assessments of Non-quantified Costs

As noted in Chapter III, our estimate of social costs focuses on compliance costs, which include the costs of construction and operation of CWWS and Cooling Towers at IPEC. With the exceptions noted above (i.e. design and permitting costs for CWWS and Cooling Towers, contingency costs for CWWS and Cooling Towers, and non-electricity related O&M costs for CWWS), we quantified all major categories of compliance costs,

There are, however, other potential categories of social costs beyond compliance costs. The following are summaries of certain potential additional categories of costs of CWWS and Cooling Towers at IPEC (EPA 2010, p. 8-9):

a. Government regulatory costs

Government regulatory costs are those borne by various government entities in the course of researching, enacting, and enforcing a policy or regulation. These would include costs incurred by state and federal regulators to establish and enforce regulations for fish protection at IPEC.

b. Distributional costs

In general, benefit-cost analysis focuses on total net benefits instead of any individual "winners" or "losers." Distributional costs are those that relate to how certain entities or societal groups are impacted by the imposition of a regulation. For example, changes in electricity prices are generally assumed to have the largest impact on the poor, because electricity costs represent a larger portion of their total household expenditures.

c. Transaction costs

Transactions costs are those incurred in making an economic exchange beyond the cost of production of a good or service. They may include the costs of searching out sellers, bargaining, and enforcing contracts for any additional required purchases.

d. Transitional costs.

Transitional costs are any short-term costs incurred during the adjustment to a new market equilibrium. These costs may include the costs of training workers in the use of new pollution control equipment.

4. Summary and Implications of Non-quantified Costs and Benefits

We conclude that the additional benefits and cost categories discussed above—which are not quantified—are not likely to be significant. As a result, none of these non-quantified benefit and cost categories, individually or collectively, is likely to significantly affect the comparisons of benefits and costs of CWWS and Cooling Towers at IPEC. Thus, our two principal conclusions—that costs exceed benefits for both technologies and that Cooling Towers are dominated by CWWS—are robust with respect to omitted costs and benefits.

VI. Uncertainty Analyses

The quantitative benefit-cost results presented thus far can be thought of as our "base-case" results. The estimates of the individual components of costs and benefits are based on sound methods applied by experts in the relevant fields using technical information, analysis of biological sampling data, reasonable assumptions, and best professional judgment. Aside from the assumptions that we have noted above that are likely to cause costs or benefits to be overstated or understated, the base-case estimates and assumptions represent "best" estimates.

In this chapter, we further examine the robustness of our basic conclusions by accounting for the fact that some of the components of the benefit and cost estimates are subject to some degree of uncertainty. We address those uncertainties systematically to identify the magnitudes of the potential uncertainties in our estimates of net costs and, when relevant, the probabilities associated with different outcomes. We begin by discussing the role of uncertainty analysis. We then present results from the two well-accepted types of uncertainty analyses that we have conducted: sensitivity analysis and Monte Carlo analysis. Both types of analysis provide strong support for our conclusions that the costs of CWWS and Cooling Towers are likely to far outweigh their benefits and that the Cooling Towers alternative has higher costs and lower benefits than the CWWS alternative.

A. Background on Uncertainty Analysis

Economists and policy analysts have long recognized that analyses of costs and benefits, no matter how careful and thorough, inevitably are subject to some degree of uncertainty. A robust cost-benefit analysis will include either a discussion of the major uncertainties or a formal quantitative analysis of uncertainty.

Sensitivity analyses and Monte Carlo simulation are the two most widely used approaches to considering uncertainty in a quantitative manner. Sensitivity analyses help to determine which uncertainties are most critical and whether plausible changes in the parameter values and assumptions could change the conclusions reached using base-case assumptions. Monte Carlo analysis goes further, generating not just a range of possible outcomes, but also a formalized mechanism for estimating the likelihoods of different outcomes.

1. Guidelines on the Treatment of Uncertainty in Benefit-Cost Analysis

Guidelines on benefit-cost analysis from EPA, OMB, and New York State address the importance of uncertainty analysis and the conditions under which quantitative uncertainty analysis should be undertaken. These guidelines are primarily focused on the analysis of new rules; however, for site-specific regulatory decisions and analysis, it is fitting to apply the same principles used in broader rulemakings.

a. New York State

New York State guidelines for benefit-cost assessments issued by the Governor's Office of Regulatory Reform also instruct analysts to consider uncertainty. The guidelines state, "The presentation must also include enough discussion of the limitations, uncertainties and sensitivities of each part of the analysis to permit others to assess the results of the analysis (e.g., … if certain factual estimates, if off by a slight percentage, would drastically alter the conclusions reached)" (NY Governor's Office of Regulatory Reform 2008, p. 17).

b. EPA Guidelines

EPA's *Guidelines* states that "[E]very analysis should address uncertainties resulting from the choices the analyst has made" (EPA 2010, p. 11-11). EPA stresses the importance of assessing and describing uncertainty in economic analyses and notes that the impact of using alternative assumptions or alternative models can be assessed quantitatively.

EPA notes that sensitivity analyses can be useful to assess how a model's output changes as one of its input parameters change (EPA 2010, p. 11-11), and that the importance of statistical variability is commonly assessed using Monte Carlo analyses (EPA 2010, p. 11-9).

EPA's *Guidelines* also recognize that consideration of all possible uncertainties is not possible or even desirable. As a result, uncertainty analyses should focus on the most critical uncertainties, those most likely to make a material difference to decision makers:

> Because performing an alternative analysis on all the assumptions in an analysis is prohibitively resource intensive, the analyst should focus on the assumptions that have the largest impact on the final results of the particular analysis (EPA 2010, p. 11-11).

c. OMB Guidelines

In its most recent guidance for regulatory agencies, OMB stresses that important uncertainties connected with regulatory decisions need to be analyzed and presented as part of an overall regulatory analysis (OMB 2003).

OMB suggests providing some estimate of the probability distribution of the results along with some estimates of central tendency (e.g., mean or median) and other descriptive statistics (e.g., standard deviation, percentile estimates). As with the EPA guidelines, OMB recommends sensitivity analysis and Monte Carlo simulation to address uncertainty.

OMB provides specific guidance on when a quantitative analysis of uncertainty is appropriate. For "major rules" involving "annual economic effects" of $1 billion or more, a formal uncertainty analysis is required. OMB also recommends a rigorous approach to uncertainty in regulations for which "net benefits are close to zero" (OMB 2003).

In other situations (when economic effects are less than $1 billion and net benefits are not close to zero), OMB suggests the following:

Disclose qualitatively the main uncertainties in each important input to the calculation of benefits and costs. These disclosures should address the uncertainties in the data as well as in the analytical results (OMB 2003).

2. Treatments of Uncertainty

Sensitivity analyses and Monte Carlo simulation are two of the most common approaches to considering uncertainty. Analyses of uncertainty typically begin with sensitivity analyses to help determine which uncertainties are most critical and whether plausible changes in the parameter values and assumptions could change the conclusions reached using base-case assumptions. Monte Carlo analysis goes further, generating not just a range of possible outcomes, but also a formalized mechanism for estimating the likelihoods of different outcomes.

a. Sensitivity Analysis

Sensitivity analysis provides a means to determine the effects of uncertainties in different input parameters on the overall results—in this case, the net costs of CWWS and Cooling Towers at IPEC. "The purpose of sensitivity analysis is to acknowledge underlying uncertainty. In particular, it should convey how sensitive predicted net benefits are to changes in assumptions. If the sign of net benefits does not change when we consider the range of reasonable assumptions, then our results are robust and we can have greater confidence in them" (Boardman et al. 2011, p. 177).

Sensitivity analysis involves varying key input parameters, both one at a time and in combination, over appropriate ranges to determine their effects on net costs (Boardman et al. 2011). Such analyses are often more appropriately termed "partial" sensitivity analysis. "Partial sensitivity is most appropriately applied to what the analyst believes to be the most important and uncertain assumptions" (Boardman et al. 2011, p. 178).

One of the advantages of using sensitivity analysis is its computational ease. It is relatively easy to modify the values of key inputs to see how they affect the results. For each parameter considered, typically "low" and "high" values are tested in addition to the base-case value.

b. Quantitative Monte Carlo Analysis

Quantitative Monte Carlo analysis, or Monte Carlo simulation, is a computer-assisted method of uncertainty analysis. It uses statistical sampling techniques to approximate a probability distribution that generally cannot be derived analytically from the point estimates of the individual parameters. Monte Carlo analysis has emerged as an important method for developing formal quantitative uncertainty assessments, and it can be particularly useful because it explicitly characterizes analytical uncertainty and variability (EPA 2010, p. 11-9). Additional details on the general theory of Monte Carlo analysis are provided in Appendix G.

Whereas sensitivity analyses involve specifying only "low" and "high" values for parameters, Monte Carlo analysis requires explicitly defining a probability distribution of the values for each parameter to be included in the analysis. The probability distributions capture the ranges of possible values the inputs might take and the likelihoods of the occurrences of these values. Input values associated with higher probabilities will be selected more often during the simulation, while input values associated with lower probabilities will be selected less often.

The Monte Carlo simulation draws a random sample value from each of the input probability distributions. It then uses those values to calculate a value for the outcome measure(s) (in the case of benefit-cost analysis, the primary measure is net benefits or net costs). This represents one iteration or trial of the simulation. This process is then repeated a large number of times (often thousands of times) to "simulate" the probability distribution of the result (in this case, net costs). The greater the number of random trials run, the more precisely the probability distribution of the outcome measure can be estimated.

An example illustrates the nature of the calculations. Suppose that total construction costs in a single year consist of two cost components, a capital cost component and a labor cost component, both of which are uncertain. Suppose further that the uncertainty in each component is independent of the other component. If so, the uncertainty in each component can be characterized by a probability distribution that does not vary with the value of the other component. The Monte Carlo simulation will sample a value from the distribution of capital costs and a value from the distribution of labor costs. It then will add the two values to calculate an estimate of total construction costs. This sampling process is one iteration or trial of the simulation. When the sampling process is repeated many times, the result is a distribution of total construction costs. An equivalent Monte Carlo analysis can be applied to both benefits and costs in order to estimate the distribution of net costs.

B. Sensitivity Analyses of Costs and Benefits of Cylindrical Wedgewire Screens and Cooling Tower Alternatives

We identified nine different parameters that could have significant impacts on net costs and that are subject to some degree of uncertainty. We group them as follows.

- Two parameters only affecting cost estimates:
  - construction costs; and
  - wholesale electricity prices.
- Five parameters only affecting the benefits estimates:
  - biological effectiveness of the CWWS alternative;
  - share of fish that are harvested for commercial use vs. recreational use for all modeled fish species;
  - recreational harvest value;
  - commercial fish prices; and

- the extent to which commercial benefits may be reduced by incremental costs or entry into open-access fisheries resulting from higher catches.

- Two parameters affecting implementation schedules, which affect both costs and benefits:
  - Cooling Towers permitting and construction schedule; and
  - Cooling Towers construction outage length (assuming concurrent operation of IPEC with blasting).

1. Parameters Affecting Estimated Costs

a. Construction Costs

Construction cost estimates for projects expected to be undertaken at some point in the future are always uncertain. ENERCON (2013a) provides an expected accuracy range for their CWWS construction cost estimates of -10% / +20%. We apply this range to the base-case CWWS construction costs to find "low" and "high" case construction cost values. Tetra Tech (2013) does not provide a range for their Cooling Tower construction cost estimates, although it did include an additional 25 percent amount for contingencies, which, as discussed above, we did not include in our cost estimates. We do not have any information on the relative magnitudes of the uncertainty between the construction costs for the two alternatives, so we apply the same -10% / +20% range to the construction costs for the Cooling Towers alterative, even though the costs of more conceptual Cooling Tower designs may be expected to be more uncertain than those for the CWWS.

Table 23. Estimated Costs and Benefits with Alternative Construction Costs

	Costs	Benefits	Net Costs	Change in Net Costs
r = 3%				
Base Case				
CWWS	$169.5	$11.3	$158.2	
Cooling Towers	$1,056.6	$1.2	$1,055.4	
Cooling Towers Incremental to CWWS	+$887.1	-$10.1	+$897.3	
Low Construction Costs				
CWWS	$152.1	Base	$140.8	-$17.4
Cooling Towers	$997.1	Base	$995.9	-$59.5
Cooling Towers Incremental to CWWS	+$845.0	Base	+$855.1	-$42.1
High Construction Costs				
CWWS	$204.3	Base	$193.0	$34.8
Cooling Towers	$1,175.7	Base	$1,174.5	$119.0
Cooling Towers Incremental to CWWS	+$971.4	Base	+$981.5	+$84.3
r = 7%				
Base Case				
CWWS	$123.8	$6.1	$117.7	
Cooling Towers	$670.9	$0.6	$670.2	
Cooling Towers Incremental to CWWS	+$547.0	-$5.5	+$552.5	
Low Construction Costs				
CWWS	$111.2	Base	$105.1	-$12.6
Cooling Towers	$631.5	Base	$630.9	-$39.4
Cooling Towers Incremental to CWWS	+$520.3	Base	+$525.8	-$26.7
High Construction Costs				
CWWS	$149.1	Base	$143.0	$25.2
Cooling Towers	$749.6	Base	$749.0	$78.7
Cooling Towers Incremental to CWWS	+$600.5	Base	+$606.0	+$53.5

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. "Base" indicates that a value is unchanged from the base case.
Source: NERA calculations as explained in text

As shown in Table 23, the "high" estimates of construction costs increase the present value of net costs by about $35 million for CWWS and about $119 million for Cooling Towers at a 3 percent discount rate. Conversely, the "low" estimate of construction costs reduces the present value of net costs by about $17 million for CWWS and about $60 million for Cooling Towers. These results do not change our conclusions that costs are substantially greater than benefits for both alternatives and that Cooling Towers are dominated by CWWS (i.e., Cooling Towers have lower benefits and higher costs).

b. Wholesale Electricity Prices

Both CWWS and Cooling Towers lead to changes in IPEC electricity generation. As discussed in Chapter III, there are three sources of potential electricity generation losses: construction outages, efficiency losses, and parasitic losses. We estimate the costs of these changes by multiplying the changes by forecasted wholesale electricity prices. As a result, electricity price forecasts affect power replacement costs; lower-than-forecasted electricity prices would decrease the cost of replacement power, and higher electricity prices would have the opposite effect.

Electricity prices have historically been volatile and forecasts involve a number of modeling assumptions and are thus subject to some uncertainty. To quantify the impact of different electricity prices, we performed sensitivity analyses with higher and lower electricity prices than those used in the base-case analysis, which are based on the "Reference Case" price forecast for New York City and Westchester County developed by the Energy Information Administration (EIA) of the Department of Energy in its Annual Energy Outlook 2013 (EIA 2013). For our "high" price sensitivity case, we use prices 40% higher than the EIA (2013) Reference Case prices in each forecast year; for the "low" price sensitivity case, we similarly use prices 40% lower than the EIA (2013) Reference Case.[20]

[20] This sensitivity range is close to the maximum range of comparable electricity prices in two EIA (2013) side case projections – the Low and High Oil and Gas Resource cases. These side cases primarily reflect uncertainty in the supply of natural gas, which is a key determinant of future electricity prices.

Table 24. Estimated Costs and Benefits with Alternative Wholesale Electricity Prices

	Costs	Benefits	Net Costs	Change in Net Costs
r = 3%				
Base Case				
CWWS	$169.5	$11.3	$158.2	
Cooling Towers	$1,056.6	$1.2	$1,055.4	
Cooling Towers Incremental to CWWS	+$887.1	-$10.1	+$897.3	
Low Wholesale Electricity Price				
CWWS	$171.3	Base	$159.9	$1.8
Cooling Towers	$833.8	Base	$832.6	-$222.8
Cooling Towers Incremental to CWWS	+$662.5	Base	+$672.7	-$224.6
High Wholesale Electricity Price				
CWWS	$167.7	Base	$156.4	-$1.8
Cooling Towers	$1,279.4	Base	$1,278.2	$222.8
Cooling Towers Incremental to CWWS	+$1,111.7	Base	+$1,121.8	+$224.6
r = 7%				
Base Case				
CWWS	$123.8	$6.1	$117.7	
Cooling Towers	$670.9	$0.6	$670.2	
Cooling Towers Incremental to CWWS	+$547.0	-$5.5	+$552.5	
Low Wholesale Electricity Price				
CWWS	$124.8	Base	$118.7	$0.9
Cooling Towers	$536.8	Base	$536.1	-$134.1
Cooling Towers Incremental to CWWS	+$412.0	Base	+$417.4	-$135.1
High Wholesale Electricity Price				
CWWS	$122.9	Base	$116.8	-$0.9
Cooling Towers	$805.0	Base	$804.4	$134.1
Cooling Towers Incremental to CWWS	+$682.1	Base	+$687.6	+$135.1

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. "Base" indicates that a value is unchanged from the base case. Changes in electricity prices have opposite cost impacts on CWWS and Cooling Towers because CWWS causes a net increase in electricity generation at IPEC while Cooling Towers causes construction outages and a net loss in ongoing generation.

Source: NERA calculations as explained in text

Table 24 presents the results. Lower (higher) electricity prices cause the total costs of CWWS to increase (decrease) by about $1.8 million at a 3 percent discount rate. Costs increase when electricity prices decrease because the use of CWWS results in a net *increase* in electricity output at IPEC; this net increase is actually a benefit valued at the wholesale price of electricity. Total costs for Cooling Towers move in the opposite direction, since the installation of Cooling Towers requires a construction outage and ongoing generation losses at IPEC. The sizes of the changes are much larger for Cooling Towers; total costs decrease by about $223 million in the "low" electricity price case and increase by the same amount in the "high" electricity price case at a 3 percent discount rate.

Alternative electricity prices do not affect the conclusions that costs exceed benefits for both alternatives and that Cooling Towers are dominated by CWWS.

2. Parameters Affecting Estimated Benefits

a. Efficacy of CWWS

Our base-case benefits estimates are based on theoretical fishery harvest impacts developed by ASA Analysis & Communication (ASAAC 2013). The fishery impact estimates for CWWS are subject to some uncertainty, and ASAAC provided an upper and lower bound on the fishery impacts in ASAAC (2013) to reflect that uncertainty. We use these two bounds on CWWS efficacy as "low" and "high" sensitivity cases.

Table 25. Estimated Costs and Benefits with Alternative CWWS Efficacy

	Costs	Benefits	Net Costs	Change in Net Costs
r = 3%				
Base Case				
CWWS	$169.5	$11.3	$158.2	
Cooling Towers	$1,056.6	$1.2	$1,055.4	
Cooling Towers Incremental to CWWS	+$887.1	-$10.1	+$897.3	
Low CWWS Efficacy				
CWWS	Base	$10.6	$158.9	$0.7
Cooling Towers	Base	Base	Base	$0.0
Cooling Towers Incremental to CWWS	Base	-$9.4	+$896.5	-$0.7
High CWWS Efficacy				
CWWS	Base	$11.6	$157.9	-$0.2
Cooling Towers	Base	Base	Base	$0.0
Cooling Towers Incremental to CWWS	Base	-$10.4	+$897.5	+$0.2
r = 7%				
Base Case				
CWWS	$123.8	$6.1	$117.7	
Cooling Towers	$670.9	$0.6	$670.2	
Cooling Towers Incremental to CWWS	+$547.0	-$5.5	+$552.5	
Low CWWS Efficacy				
CWWS	Base	$5.7	$118.1	$0.4
Cooling Towers	Base	Base	Base	$0.0
Cooling Towers Incremental to CWWS	Base	-$5.1	+$552.1	-$0.4
High CWWS Efficacy				
CWWS	Base	$6.2	$117.6	-$0.1
Cooling Towers	Base	Base	Base	$0.0
Cooling Towers Incremental to CWWS	Base	-$5.6	+$552.6	+$0.1

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. "Base" indicates that a value is unchanged from the base case.
Source: NERA calculations as explained in text

Table 25 shows CWWS costs and benefits for the "low" and "high" efficacy cases. Benefits increase by about $0.2 million in the "high" efficacy case and decrease by about $0.7 million in the "low" efficacy case using a 3 percent discount rate. Even in the "high" efficacy case (which is most favorable to CWWS), the costs of CWWS are still over ten times larger than the benefits. Cooling Towers are again dominated by CWWS even in the "low" efficacy case.

b. Recreational-Commercial Split of Fish Harvest

Fish harvested recreationally are valued differently than fish harvested commercially, so we use historical harvest data to separate total fish harvest losses due to different CWIS at IPEC into recreational losses and commercial losses. In the base case, we estimate average fish harvest shares using 2003 to 2012 NMFS (2013a & 2013b) data on commercial and recreational landings for different fish species.

There is some uncertainty about what these recreational and commercial landings shares will be in future years. To test the sensitivity of our net cost results to the allocation of fish harvest losses between recreational and commercial fisheries, we ran simulations using the minimum and maximum of annual commercial harvest share for each of our four modeled species over the ten-year period from 2003 to 2012 rather than the average over the whole period.

Table 26. Estimated Costs and Benefits with Alternative Commercial Harvest Percentages

	Costs	Benefits	Net Costs	Change in Net Costs
r = 3%				
Base Case				
CWWS	$169.5	$11.3	$158.2	
Cooling Towers	$1,056.6	$1.2	$1,055.4	
Cooling Towers Incremental to CWWS	+$887.1	-$10.1	+$897.3	
Low Harvest % Commercial				
CWWS	Base	$11.8	$157.7	-$0.5
Cooling Towers	Base	$1.2	$1,055.4	-$0.1
Cooling Towers Incremental to CWWS	Base	-$10.6	+$897.7	+$0.5
High Harvest % Commercial				
CWWS	Base	$10.4	$159.1	$0.9
Cooling Towers	Base	$1.1	$1,055.5	$0.1
Cooling Towers Incremental to CWWS	Base	-$9.3	+$896.5	-$0.8
r = 7%				
Base Case				
CWWS	$123.8	$6.1	$117.7	
Cooling Towers	$670.9	$0.6	$670.2	
Cooling Towers Incremental to CWWS	+$547.0	-$5.5	+$552.5	
Low Harvest % Commercial				
CWWS	Base	$6.4	$117.5	-$0.3
Cooling Towers	Base	$0.7	$670.2	$0.0
Cooling Towers Incremental to CWWS	Base	-$5.7	+$552.7	+$0.2
High Harvest % Commercial				
CWWS	Base	$5.6	$118.2	$0.5
Cooling Towers	Base	$0.6	$670.3	$0.1
Cooling Towers Incremental to CWWS	Base	-$5.0	+$552.1	-$0.4

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. "Base" indicates that a value is unchanged from the base case.
Source: NERA calculations as explained in text

As shown in Table 26, uncertainty in the allocation of fish harvest losses between recreational and commercial use has only a small impact on the benefits of CWWS and Cooling Towers alternatives. CWWS benefits increase by $0.5 million and Cooling Tower benefits increase about $0.1 million in the sensitivity case with low commercial harvest shares (at a 3 percent discount rate). This is because all recreational harvests are valued using the recreational value of striped bass harvest, which is higher than any commercial fish value. Benefits of CWWS and Cooling Towers decrease by $0.9 million and $0.1 million respectively in the sensitivity case with high commercial harvest shares and low recreational harvest shares.

In each sensitivity case, costs are much larger than benefits for both CWWS and Cooling Towers, and Cooling Tower have higher costs and lower benefits than CWWS.

c. Recreational Values

As discussed in Appendix D, we developed estimates of recreational fish values using a statistical "meta-analysis" that derives an estimate of the marginal value of increased harvest. That analysis yields a marginal value of $66.84 per striped bass harvested, which we conservatively apply to gains in recreational harvest of striped bass, American shad, white perch, and *Alosa sp*. However, this value is uncertain because of uncertainty in the estimated value of the coefficient ("β"), the parameter determining the recreational fishing value. To test the sensitivity of the results to the estimated recreational value of striped bass, we ran simulations with values of β corresponding to the 10th and 90th percentiles. That resulted in a "high" value of $91.76/fish and a "low" value of $41.91/fish.

Table 27. Estimated Costs and Benefits with Alternative Recreational Fish Values

	Costs	Benefits	Net Costs	Change in Net Costs
r = 3%				
Base Case				
CWWS	$169.5	$11.3	$158.2	
Cooling Towers	$1,056.6	$1.2	$1,055.4	
Cooling Towers Incremental to CWWS	+$887.1	-$10.1	+$897.3	
Low Recreational Fish Value				
CWWS	Base	$7.2	$162.3	$4.1
Cooling Towers	Base	$0.7	$1,055.9	$0.4
Cooling Towers Incremental to CWWS	Base	-$6.4	+$893.6	-$3.7
High Recreational Fish Value				
CWWS	Base	$15.4	$154.0	-$4.1
Cooling Towers	Base	$1.6	$1,055.0	-$0.4
Cooling Towers Incremental to CWWS	Base	-$13.8	+$901.0	+$3.7
r = 7%				
Base Case				
CWWS	$123.8	$6.1	$117.7	
Cooling Towers	$670.9	$0.6	$670.2	
Cooling Towers Incremental to CWWS	+$547.0	-$5.5	+$552.5	
Low Recreational Fish Value				
CWWS	Base	$3.9	$120.0	$2.2
Cooling Towers	Base	$0.4	$670.5	$0.2
Cooling Towers Incremental to CWWS	Base	-$3.5	+$550.5	-$2.0
High Recreational Fish Value				
CWWS	Base	$8.3	$115.5	-$2.2
Cooling Towers	Base	$0.9	$670.0	-$0.2
Cooling Towers Incremental to CWWS	Base	-$7.5	+$554.5	+$2.0

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. "Base" indicates that a value is unchanged from the base case.
Source: NERA calculations as explained in text

Table 27 presents the results. The use of a high value for recreational catch has the expected effect of increasing benefits. The increased benefits relative to the base case are about $4 million for CWWS and $0.5 million for Cooling Towers at a 3 percent discount rate. While this is a large proportional increase, the higher benefits are not sufficient to result in positive net benefits. Costs remain much greater than benefits in all scenarios. Similarly, the "low" recreational value increases net costs. In each case, Cooling Towers have lower benefits and higher costs than CWWS.

d. Commercial Fish Prices

Our base-case analysis uses the average of commercial fish prices for each species over the ten-year period from 2003 to 2012 to value increases in commercial harvest. Higher commercial fish prices would increase the benefits of CWWS and Cooling Towers. Lower prices would reduce benefits. To address the potential impact of these uncertainties, we ran sensitivity analyses that used the maximum or minimum prices over the ten-year period for the four harvested fish species – American shad, striped bass, white perch, and *Alosa sp.*

Table 28. Estimated Costs and Benefits with Alternative Commercial Fish Prices

	Costs	Benefits	Net Costs	Change in Net Costs
r = 3%				
Base Case				
CWWS	$169.5	$11.3	$158.2	
Cooling Towers	$1,056.6	$1.2	$1,055.4	
Cooling Towers Incremental to CWWS	+$887.1	-$10.1	+$897.3	
Low Commercial Fish Prices				
CWWS	Base	$11.3	$158.2	$0.05
Cooling Towers	Base	$1.2	$1,055.4	$0.00
Cooling Towers Incremental to CWWS	Base	-$10.1	+$897.2	-$0.04
High Commercial Fish Prices				
CWWS	Base	$11.4	$158.1	-$0.06
Cooling Towers	Base	$1.2	$1,055.4	-$0.01
Cooling Towers Incremental to CWWS	Base	-$10.2	+$897.3	$0.05
r = 7%				
Base Case				
CWWS	$123.8	$6.1	$117.7	
Cooling Towers	$670.9	$0.6	$670.2	
Cooling Towers Incremental to CWWS	+$547.0	-$5.5	+$552.5	
Low Commercial Fish Prices				
CWWS	Base	$6.1	$117.8	$0.03
Cooling Towers	Base	$0.6	$670.2	$0.00
Cooling Towers Incremental to CWWS	Base	-$5.4	+$552.5	-$0.02
High Commercial Fish Prices				
CWWS	Base	$6.1	$117.7	-$0.03
Cooling Towers	Base	$0.6	$670.2	$0.00
Cooling Towers Incremental to CWWS	Base	-$5.5	+$552.5	$0.03

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. "Base" indicates that a value is unchanged from the base case.
Source: NERA calculations as explained in text

The use of higher commercial fish prices results in larger benefits for all alternatives. As shown in Table 28, benefits increase in the "high" prices case by $0.06 million for CWWS and $0.01

million for Cooling Towers using a 3 percent discount rate. This change is very small relative to costs in the base case, so these sensitivity cases do not change the conclusion that both CWWS and Cooling Towers would lead to large net costs.

Using low commercial prices for each fish species reduces benefits by $0.05 million for CWWS and by less than $0.01 million for Cooling Towers using a 3 percent discount rate, but has little proportional impact on net costs. In both cases, Cooling Towers continue to have higher costs and lower benefits than CWWS.

e. Assumptions About Costs of Higher Commercial Catch

As discussed in Chapter IV, there are some incremental costs of catching additional fish resulting from larger fish stocks. These additional costs reduce the commercial fishing benefits of CWWS and Cooling Towers. In our base case, we adopt species- and region-specific EPA estimates of producer surplus as a percentage of gross revenues EPA (2011).

To test the sensitivity of our base case results to these factors, we ran a "high" case where 100 percent of additional commercial revenues from fish protection at IPEC are producer surplus; this case assumes no incremental costs of additional fish harvests. We also ran a "low" case where the ratios of additional commercial revenues to producer surplus are defined so that the "low" and "high" case ratios are the same distance from the base case ratios. For example, the base case ratio for striped bass is 0.67 (67% of additional revenue is surplus). The "high" case ratio is 1, and the "low" case ratio for striped bass is then 0.67 – (1 – 0.67) = 0.34.

Table 29. Estimated Costs and Benefits with Alternative Commercial Benefits Ratios

	Costs	Benefits	Net Costs	Change in Net Costs
r = 3%				
Base Case				
CWWS	$169.5	$11.3	$158.2	
Cooling Towers	$1,056.6	$1.2	$1,055.4	
Cooling Towers Incremental to CWWS	+$887.1	-$10.1	+$897.3	
Low Commercial Net Benefits Ratio				
CWWS	Base	$11.2	$158.3	$0.12
Cooling Towers	Base	$1.2	$1,055.4	$0.01
Cooling Towers Incremental to CWWS	Base	-$10.0	+$897.1	-$0.11
High Commercial Net Benefits Ratio				
CWWS	Base	$11.4	$158.0	-$0.12
Cooling Towers	Base	$1.2	$1,055.4	-$0.01
Cooling Towers Incremental to CWWS	Base	-$10.2	+$897.4	$0.11
r = 7%				
Base Case				
CWWS	$123.8	$6.1	$117.7	
Cooling Towers	$670.9	$0.6	$670.2	
Cooling Towers Incremental to CWWS	+$547.0	-$5.5	+$552.5	
Low Commercial Net Benefits Ratio				
CWWS	Base	$6.0	$117.8	$0.07
Cooling Towers	Base	$0.6	$670.2	$0.01
Cooling Towers Incremental to CWWS	Base	-$5.4	+$552.4	-$0.06
High Commercial Net Benefits Ratio				
CWWS	Base	$6.2	$117.7	-$0.07
Cooling Towers	Base	$0.7	$670.2	-$0.01
Cooling Towers Incremental to CWWS	Base	-$5.5	+$552.6	$0.06

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. "Base" indicates that a value is unchanged from the base case.
Source: NERA calculations as explained in text

Table 29 summarizes the results. Benefits increase by about $0.12 million for CWWS and $0.01 million for Cooling Towers in the "high" commercial benefits ratio case at a 3 percent discount rate, since a greater share of additional commercial revenues accrues to producers as surplus. Conversely, benefits are lower in the case with "low" commercial benefits ratios. However, these changes are very small even relative to benefits, so they do not have a significant impact on net costs for either CWWS or Cooling Towers.

3. Sensitivity Analyses Affecting Implementation Schedules (Costs and Benefits)

a. Cooling Towers Permitting and Construction Schedule Cooling Tower Construction Outage Length

In our base case, we assume an eight-year implementation period for Cooling Towers—the midpoint of seven- to nine-year implementation schedule estimated in Tetra Tech (2013). However, there is considerable uncertainty about the actual schedule for Cooling Tower implementation at IPEC.

To test the sensitivity of our results to alternative schedule assumptions on the Cooling Towers construction schedule, we define "short" and "long" implementation schedules. For the "short" schedule, we reduce the construction period by one year to make the total implementation period seven years—the low end of Tetra Tech's estimated range for the full project; under this schedule, Cooling Towers would begin operating in July 2025 (just one year after the start of CWWS operation). If there is no overlap of permitting, final design, and construction periods, Tetra Tech's (2013) timing estimates sum to as long as twelve years.[21] We use this as our "long" schedule, though ENERCON (2010a) and Young/Sommer (2013) estimates both imply even longer implementation periods.[22] In this sensitivity, Cooling Towers would begin operation in July 2030.

In each sensitivity case, we assume the total costs for each phase of implementation remain unchanged; however, because the timing of phases changes, the present value of those costs is affected. For example, the "short" schedule results in higher cumulative present value costs for Cooling Towers because some construction costs are incurred earlier than in the base case.

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[21] The following are commentaries on the timing of individual stages for Cooling Towers in Tetra Tech (2013). "It is not unreasonable to assume the permitting effort alone would take 3 to 5 years, while the final design effort required to produce construction-level plans and drawings could easily lag behind final approval by 1 year or more." (p. 27). "Construction could occur over a period of approximately 4-6 years." (p. 77).

[22] Young/Sommer (2013) estimate a minimum local permitting period of 7.1 years and an expected local permitting period of 13.8 years, both beginning after BTA identification and issuance of SEIS; the maximum permitting estimate in Tetra Tech (2013) is 5 years. ENERCON (2010a, p. v) estimates a total implementation period of almost 13 years.

Table 30. Estimated Costs and Benefits with Alternative Permitting and Construction Schedules

	Costs	Benefits	Net Costs	Change in Net Costs
r = 3%				
Base Case				
CWWS	$169.5	$11.3	$158.2	
Cooling Towers	$1,056.6	$1.2	$1,055.4	
Cooling Towers Incremental to CWWS	+$887.1	-$10.1	+$897.3	
Short Permitting and Construction Period				
CWWS	Base	Base	Base	$0.0
Cooling Towers	$1,138.7	$1.3	$1,137.4	$81.9
Cooling Towers Incremental to CWWS	+$969.2	-$10.0	+$979.2	+$81.9
Long Permitting and Construction Period				
CWWS	Base	Base	Base	$0.0
Cooling Towers	$1,010.6	$0.8	$1,009.9	-$45.6
Cooling Towers Incremental to CWWS	+$841.1	-$10.6	+$851.7	-$45.6
r = 7%				
Base Case				
CWWS	$123.8	$6.1	$117.7	
Cooling Towers	$670.9	$0.6	$670.2	
Cooling Towers Incremental to CWWS	+$547.0	-$5.5	+$552.5	
Short Permitting and Construction Period				
CWWS	Base	Base	Base	$0.0
Cooling Towers	$740.0	$0.7	$739.3	$69.1
Cooling Towers Incremental to CWWS	+$616.2	-$5.4	+$621.6	+$69.1
Long Permitting and Construction Period				
CWWS	Base	Base	Base	$0.0
Cooling Towers	$556.7	$0.4	$556.3	-$113.9
Cooling Towers Incremental to CWWS	+$432.8	-$5.7	+$438.6	-$113.9

Note: All values are present values as of January 1, 2013 in millions. "Base" indicates that a value is unchanged from the base case.

Source: NERA calculations as explained in text

Table 30 shows that under a seven-year permitting and construction period (the "short" case), Cooling Towers benefits rise by about $0.1 million but costs also rise by about $82 million at a 3 percent discount rate. Benefits rise in this case because Cooling Towers begin operation one year earlier than in the base case; the present value of costs rises because some of the costs are incurred earlier as part of the accelerated schedule (and are therefore discounted at a lower rate). The opposite occurs in the "long" case – Cooling Towers benefits fall by about $0.4 million and costs also fall by about $46 million at a 3 percent discount rate. Cooling Towers continue to be dominated by CWWS in both cases.

b. Cooling Tower Construction Outage Length

Assuming concurrent IPEC operation and blasting is possible, Tetra Tech (2013) estimates that Cooling Tower tie-in would require 35 weeks of shutdown of both units at the end of the construction period, less 5 weeks for a concurrent scheduled maintenance outage for Unit 2. These outage estimates are used in our base case estimates. ENERCON (2010b), however, estimates a construction outage period of 42 weeks for both units, less 4 weeks for a scheduled outage for Unit 2 (ENERCON 2010b, p. 46); these estimates also assume the continued operation of both units during blasting (ENERCON 2010b, p.25). Table 31 shows the sensitivity of our cost and benefits estimates to ENERCON's (2010b) estimates of the Cooling Tower construction outage lengths. For the purpose of this analysis, we assume the construction costs and the length of the design and construction period remain the same.

Table 31. Estimated Costs and Benefits with Alternative Construction Outage Length

	Costs	Benefits	Net Costs	Change in Net Costs
r = 3%				
Base Case -- Tetra Tech (2013) Cooling Tower Outage Length				
CWWS	$169.5	$11.3	$158.2	
Cooling Towers	$1,056.6	$1.2	$1,055.4	
Cooling Towers Incremental to CWWS	+$887.1	-$10.1	+$897.3	
ENERCON (2010b) Cooling Tower Outage Length				
CWWS	Base	Base	Base	$0.0
Cooling Towers	$1,158.7	$1.3	$1,157.4	$102.0
Cooling Towers Incremental to CWWS	+$989.2	-$10.0	+$999.2	+$102.0
r = 7%				
Base Case -- Tetra Tech (2013) Cooling Tower Outage Length				
CWWS	$123.8	$6.1	$117.7	
Cooling Towers	$670.9	$0.6	$670.2	
Cooling Towers Incremental to CWWS	+$547.0	-$5.5	+$552.5	
ENERCON (2010b) Cooling Tower Outage Length				
CWWS	Base	Base	Base	$0.0
Cooling Towers	$733.7	$0.7	$733.0	$62.7
Cooling Towers Incremental to CWWS	+$609.9	-$5.4	+$615.2	+$62.7

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. "Base" indicates that a value is unchanged from the base case.
Source: NERA calculations as explained in text

Table 23 shows that the longer construction outage period estimated by ENERCON (2010b) leads to an increase in net costs for Cooling Towers of $102 million at a 3 percent discount rate and about $63 million at a 7 percent discount rate. (Note that benefits are slightly larger for the sensitivity case because we assume there would be no fish losses during the additional weeks IPEC is assumed not to operate during the construction outage.)

These results reinforce our conclusions that costs are substantially greater than benefits for both alternatives and that Cooling Towers are dominated by CWWS (i.e., Cooling Towers have lower benefits and higher costs).

4. Sensitivity Analyses Changing Multiple Parameters

Thus far, our sensitivity analyses have varied only one parameter at a time. In reality, of course, multiple parameters may differ from their base-case values simultaneously. The number of possible combinations of values is huge, and is best addressed by the Monte Carlo analysis we present below. Here we provide upper and lower bounds by combining all of the values favorable to CWWS or Cooling Towers or all of those unfavorable to them. Table 29 summarizes the parameters varied and the assumptions used in the Base case, the All-Favorable case, and the All-Unfavorable case.

Note that these two extreme cases are highly unlikely because they assume that all of the uncertainties are resolved in the same way, either in a manner favorable to CWWS and Cooling Towers or in a manner unfavorable to them. As one well-known text on benefit-cost analysis notes:

> ...if we believe that values near the base-case assumptions are more likely to occur than values near the extremes of their plausible ranges, then the worst and best cases are highly unlikely to occur because they require the joint occurrence of a large number of independent low-probability events. (Boardman et al. 2011, p. 184)

Table 32. Summary of Parameters in Extreme Sensitivity Analysis

	Base Value	All-Favorable Case	All-Unfavorable Case	Source
Cost Parameters				
Construction Costs				
CWWS	$173.9 million (3% D.R.)	-10%	+20%	ENERCON (2013a)
Cooling Towers	$595.2 million (3% D.R.)	-10%	+20%	NERA assumption
Electricity Prices	EIA Reference Case	-40%*	+40%*	AEO (2013) NYISO (2013)
Benefit Parameters				
CWWS Fish Protection Efficacy	Base Efficacy	High Efficacy†	Low Efficacy†	ASAAC (2013)
Commercial Share of Fish Harvest	Average, 2003-2012	Minimum, 2013-2012	Maximum, 2013-2012	NMFS (2013a, 2013b)
Recrational Values ($/fish)	$66.84	$91.76	$41.91	NERA meta-analysis
Commercial Fish Prices ($/kg)	Average, 2003-2012	Maximum, 2003-2012	Minimum, 2003-2012	NMFS (2013a)
Commercial Net Benefits Ratio	EPA (2011)	100%	Base - (100% - Base)	EPA (2011)
Schedule Parameters				
Permitting and Construction Schedule	8 years	7 years^	12 years^	Tetra Tech (2013)
Construction Outage Length	Tetra Tech (2013)	Tetra Tech (2013)	ENERCON (2010b)	Tetra Tech (2013) ENERCON (2010b)

*Electricity prices affect CWWS and Cooling Tower costs differently. In the All Favorable case, we use assumptions favoring Cooling Towers.
†High CWWS efficacy results in lower incremental benefits for Cooling Towers (and vice versa for low CWWS efficacy). It is included in the All-Favorable case because it increases CWWS benefits and does not affect non-incremental Cooling Towers benefits.
^The short schedule case increases present value costs relative to the base case. We include it in the All-Favorable case because it increases cumulative benefits.
Source: See rightmost column of table.

Table 33 summarizes the results of the two extreme sensitivity analyses. When all of the parameters are chosen to be favorable to CWWS and Cooling Towers (the "All-Favorable" case), benefits rise and costs fall, resulting in net losses substantially smaller than in the base case; net costs fall by $21 million for CWWS and about $232 million for Cooling Towers at a 3 percent discount rate. However, even in this extreme case, neither alternative has positive net benefits, and CWWS continues to dominate Cooling Towers.

Table 33. Estimated Costs and Benefits with All Favorable Assumptions and All Unfavorable Assumptions

	Costs	Benefits	Net Costs	Change in Net Costs
r = 3%				
Base Case				
CWWS	$169.5	$11.3	$158.2	
Cooling Towers	$1,056.6	$1.2	$1,055.4	
Cooling Towers Incremental to CWWS	+$887.1	-$10.1	+$897.3	
All-Favorable				
CWWS	$153.9	$16.7	$137.2	-$21.0
Cooling Towers	$825.0	$1.9	$823.1	-$232.3
Cooling Towers Incremental to CWWS	+$671.1	-$14.8	+$685.9	-$211.3
All-Unfavorable				
CWWS	$202.5	$6.0	$196.5	$38.3
Cooling Towers	$1,494.3	$0.5	$1,493.8	$438.4
Cooling Towers Incremental to CWWS	+$1,291.8	-$5.5	+$1,297.3	+$400.1
r = 7%				
Base Case				
CWWS	$123.8	$6.1	$117.7	
Cooling Towers	$670.9	$0.6	$670.2	
Cooling Towers Incremental to CWWS	+$547.0	-$5.5	+$552.5	
All-Favorable				
CWWS	$112.2	$9.0	$103.2	-$14.6
Cooling Towers	$541.1	$1.0	$540.1	-$130.1
Cooling Towers Incremental to CWWS	+$429.0	-$7.9	+$436.9	-$115.6
All-Unfavorable				
CWWS	$148.1	$3.2	$144.9	$27.2
Cooling Towers	$815.6	$0.2	$815.4	$145.1
Cooling Towers Incremental to CWWS	+$667.5	-$3.0	+$670.5	+$118.0

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars. "Base" indicates that a value is unchanged from the base case.
Source: NERA calculations as explained in text

Conversely, net costs increase considerably in the "All-Unfavorable" case to $196.5 million for CWWS and $1,493.8 million for Cooling Towers at a 3 percent discount rate. In both "extreme" sensitivity cases, costs are greater than benefits for both technologies and Cooling Towers have greater costs and lower benefits than CWWS.

5. Summary of Sensitivity Analyses

Sensitivity analyses of construction costs, electricity prices, CWWS fishery protection efficacy, the recreational and commercial shares of fish harvests, recreational fish values, commercial fish prices, commercial benefits ratios, Cooling Tower permitting and construction schedules, and Cooling Tower outage period lengths all reinforce the main conclusions of this report. In every sensitivity case, costs are much higher than benefits for both CWWS and Cooling Towers. The lowest net costs in any sensitivity case are $137 million for CWWS and $823 million for Cooling Towers at a 3 percent discount rate in the "extreme" sensitivity analysis. The highest net costs are $197 million for CWWS and $1,494 million for Cooling Towers. Comparing CWIS alternatives, the net costs of Cooling Towers are many times larger than the net costs of CWWS under a variety of alternative assumptions, and Cooling Towers are dominated by CWWS (have higher costs *and* lower benefits) in every sensitivity case.

C. Monte Carlo Analyses

This section describes the Monte Carlo analysis used to quantify the uncertainties surrounding the cost and benefit estimates. As discussed above, Monte Carlo analysis provides a more formal means of accounting for uncertainty by characterizing the probability distributions of the component estimates and calculating the resulting probability distribution of the results, in this case the net costs of CWWS and Cooling Towers. Not all potential sources of uncertainty can be included, and it is important to focus on important sources. EPA (1997) notes:

> Accounting for the important sources of uncertainty should be a key objective in Monte Carlo analysis. However, it is not possible to characterize all the sources of uncertainties associated with the models and data (USEPA 1997, p. 16).

1. Summary of Distributions Used

Our Monte Carlo analysis includes most of the same sources of uncertainty included in our sensitivity analyses. Table 34 summarizes the parameters varied and the distributions used. For each parameter we provide the mean, 10th percentile, and 90th percentile. The 90th percentile and 10th percentile provide an indication of the range of possible values for each parameter. The value drawn on any given iteration of the simulation will be greater than the 10th percentile 90 percent of the time, and less than the 90th percentile 90 percent of the time. The value drawn will lay between these values 80 percent of the time. The final column shows the probability distributions used to generate values.

Table 34. Summary of Distributions Used for Monte Carlo Analysis

	Mean	10th Percentile	90th Percentile	Distribution	Source/Notes
Cost Parameters					
Construction Costs					
CWWS	$173.9 million (3% D.R.)	-16%	+16%	Uniform, -20% to +20%	ENERCON (2013a)
Cooling Towers	$595.2 million (3% D.R.)	-16%	+16%	of base value.	NERA assumption
Electricity Prices	EIA Reference Case	-40%*	+40%*	Lognormal implied by base value and -40%/+40% range in each year. Single percentile drawn in each trial and used for all years.	EIA (2013)
Benefits Parameters					
Commercial Share of Fish Harvest (striped bass shown as example)	10%	5%	15%	Uniform fit to 2003-2012 fish landings data.	NMFS (2013a, 2013b)
Recrational Values	$66.84/fish	$41.91/fish	$91.76/fish	Normal distribution for meta-analysis 6.	NERA meta-analysis
Commercial Fish Prices (striped bass shown as example)	$6.15/kg	$5.11/kg	$7.26/kg	Lognormal fit to 2003-2012 prices.	NMFS (2013a)
Commercial Net Benefits Ratio (striped bass shown as example)	67%	41%	93%	Uniform between 100% and Base - (100% - Base)	EPA (2011)

* -40% and +40% values are used to select the standard deviation of lognormal distributions with mean equal to the base case electricity price; lognormal distributions are asymmetric.

Sources: See rightmost column of table, along with additional clarifications in the text.

- *Construction costs.* ENERCON (2013a) provides an expected range for their CWWS construction cost estimates of -10% / +20%, which we also applied to Cooling Tower construction costs in our sensitivity analysis.[23] For the Monte Carlo analysis, we use a uniform distribution with a range of -20% / +20% relative to base case construction costs for both CWWS and Cooling Towers. This retains the base value as the central value of the distribution, and it conservatively extends the accuracy range provided by ENERCON (2013a) to include additional lower-cost possibilities.

- *Electricity prices.* We use a lognormal distribution for electricity prices. Lognormal distributions are commonly used to develop stochastic models of pricing in the finance literature. In order to specify our distribution, we use the base case price as the mean of the underlying normal distribution and we use the variance that would be implied if a -40% / +40% price range were the 10th and 90th percentiles of the distribution in each forecast year.[24] We assume perfect serial correlation of the random component of electricity prices, so that a random draw results in prices at the same percentile of the

[23] Note that Tetra Tech (2013) includes an additional 25 percent of costs for contingencies, which, as discussed above, we did not include in our cost estimates.

[24] This -40% / +40% range is close to the maximum range of comparable electricity prices in two EIA (2013) side case projections – the Low and High Oil and Gas Resource cases. These side cases primarily reflect uncertainty in the supply of natural gas, which is a key determinant of future electricity prices. Note also that lognormal distributions are asymmetric, so the -40% / +40% range is merely used as a reasonable basis to estimate the variance in each year.

lognormal distributions in each year of the forecast. Although it does not account for inter-annual price volatility beyond the base case, year-to-year variability is largely irrelevant here because such fluctuations would tend to average out over time. Our approach captures the more important uncertainty – whether electricity prices will be, on average, higher or lower than base case prices in the long run.

- *CWWS efficacy*. We use base case CWWS efficacy in the Monte Carlo analysis, because we do not have information on the potential distribution of efficacy (only the upper and lower bound points as described above in our sensitivity analyses).

- *Commercial and recreational shares of fish harvest*. The harvest shares are bounded below and above (in the extreme by 0 and 100 percent), so we assume a uniform distribution. We use ten years of NMFS (2013a, b) commercial and recreational landings data for each modeled fish species to estimate a uniform distribution of harvest shares with the same mean and standard deviation as the annual historical data. All values of harvest shares between the minimum and maximum of these uniform distributions are equally likely. In two instances – American shad and *Alosa sp.* – the maximum of the implied uniform distribution for the commercial share of the total fish harvest is greater than 100 percent. In these cases we keep the same uniform distribution parameters but change any random draws over 100 percent to equal 100 percent.

- *Recreational harvest value*. The marginal value per fish harvested is proportional to the coefficient (β) estimated in our meta-analysis ordinary least squares (OLS) regression. We assume normally distributed OLS residuals, which implies that our estimate of β is also normally distributed. Thus, for the Monte Carlo analysis we use a normal distribution for β with a mean equal to the OLS estimate and a standard deviation equal to the standard error of the regression. To avoid extremely low and negative recreational fish values, we conservatively limit random draws to above the 0.5^{th} percentile.[25] The resulting distribution of marginal recreational harvest values is centered at $66.84/fish with a 10th percentile value of $41.91/fish and a 90th percentile value of $91.76/fish.

- *Commercial fish prices*. We use a log-normal distribution, which is commonly used to develop stochastic pricing models. For each fish species, we estimate the mean and standard deviation of commercial fish prices using ten years of historical data (2003 - 2012) from NMFS (2013a). We use independent random draws for each year of our Monte Carlo modeling forecasts.

- *Commercial net benefits ratios*. We assume a uniform distribution centered on the base values and with a maximum of 100 percent (i.e. all gross revenues are producer surplus); the minimum of the uniform distribution is then twice as far from 100 percent as the base value. This assumption conservatively allows for very high percentages while limiting the lower end of the distribution. For example, striped bass have a net benefits ratio of 67 percent (33 percentage points below 100 percent), so we assume the maximum for striped bass is 100 percent and the minimum is 100 – 2*33 = 34 percent. Assuming a uniform

[25] Random draws below this cutoff are expected to occur 0.5 percent of the time, once in every 200 trials.

distribution means that all net benefits ratios between 34 and 100 percent are equally likely.

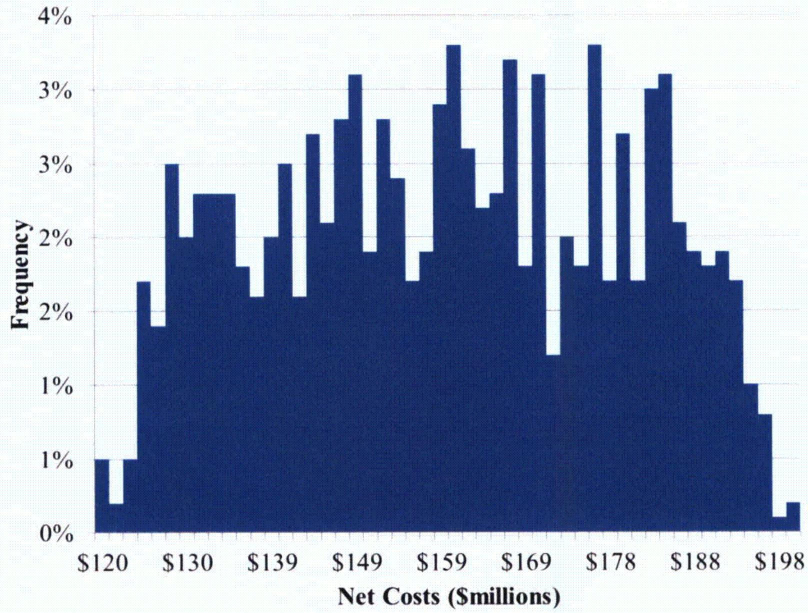
- *Cooling Tower Permitting and Construction Schedule and Construction Outage Length.* We use the base case scheduling assumptions in the Monte Carlo analysis, because we do not have any information on the potential distribution of these parameters and our sensitivity cases of scheduling parameters are highly asymmetric around the base case implementation schedules.

2. Monte Carlo Results for Net Costs of CWWS and Cooling Towers

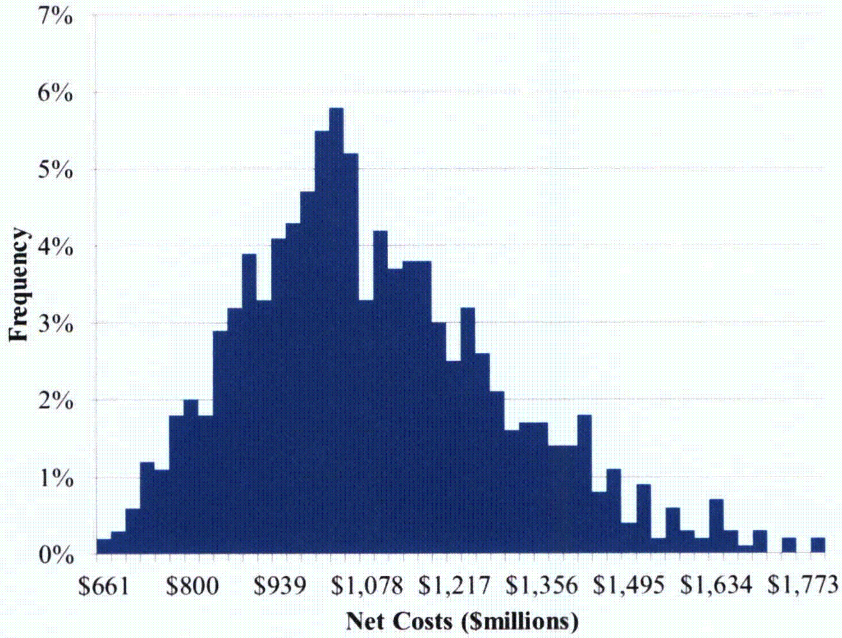
We ran the Monte Carlo simulation 1,000 times. For each trial, we randomly sampled from each of the probability distributions and then computed net costs for the sampled values. In any single Monte Carlo trial, we applied the same random draws of each parameter to both CWWS and Cooling Towers. Other than construction costs, none of the parameters included in the Monte Carlo analysis are specific to one technology. In the case of construction costs, we applied the same percentage change to both technologies because we assumed the same percentage distribution for the two technologies and because many sources of variability in construction costs are common to both technologies. Similarly, in each Monte Carlo trial we applied the same random percentile of each benefits parameter to all fish species. All of the draws *across* benefit and cost parameters and between Monte Carlo trials are independent of each other, which we believe is a reasonable assumption.

The results from the repeated trials provide a distribution of outcomes. For example, Figure 5 shows the distributions of net costs for CWWS and Cooling Towers using a probability density function (PDF). The PDF shows the probabilities associated with specific levels of net cost shown on the X-axis. The probability that net costs will be between two values is the area under the PDF between those two values.

CWWS



Cooling Towers



Source: NERA calculations as explained in text. Costs and benefits calculated using a 3 percent discount rate.

Figure 5. Histograms (Probability Density Functions) of Monte Carlo Net Costs for CWWS and Cooling Towers

Table 35. Summary of Distributions of Present Values (3 percent discount rate, $millions)

	Mean	Median	5th Pctile	95th Pctile	Minimum	Maximum
Costs						
CWWS	$170.1	$170.8	$138.8	$200.7	$132.2	$205.4
Cooling Towers	$1,079.6	$1,048.5	$776.4	$1,459.9	$638.6	$1,797.6
Benefits						
CWWS	$11.3	$11.3	$5.7	$16.6	$2.9	$20.5
Cooling Towers	$1.2	$1.2	$0.6	$1.7	$0.3	$2.1
Net Costs						
CWWS	$158.8	$159.1	$126.8	$190.7	$118.1	$199.7
Cooling Towers	$1,078.4	$1,047.3	$775.1	$1,458.9	$637.4	$1,796.4

Source: NERA calculations as explained in text

Table 35 summarizes the distributions of results for CWWS and Cooling Towers. The first two numerical columns show measures of the central tendencies of the distribution, the mean and the median. The next two columns show the 5th and 95th percentiles, respectively; 90 percent of the trials fell in that interval. Only 10 percent fell outside that interval. The 5th percentile of net costs (the low end of the net-cost distribution) was greater than zero for both CWWS and Cooling Towers. The last two columns show the absolute minimum and maximum values observed in all of the trials. Even when we look at the absolute minimums—the smallest net costs in 1,000 trials—the net costs remain positive for all alternatives. Comparing CWWS and Cooling Towers, there was not a single trial in which the net costs of Cooling Towers were lower than the net costs of CWWS. Moreover, Cooling Towers had higher costs and lower benefits than CWWS in every trial of the Monte Carlo analysis.

D. Implications of Uncertainty Analyses

Both the sensitivity analyses and the Monte Carlo simulations show that even if one makes extreme assumptions in favor of CWWS and Cooling Towers, neither alternative yields benefits greater than costs. These uncertainty analyses reinforce the conclusions reached in Chapter V based on the results using the base-case assumptions:

- Neither Cooling Towers nor CWWS comes close to passing a benefit-cost test, although we understand Entergy has communicated its commitment to CWWS despite this conclusion.

- Cooling Towers have much greater costs and lower benefits than CWWS (so that Cooling Towers are dominated by CWWS).

VII. Conclusions

This study evaluates the potential benefits and costs of CWWS and Cooling Towers to reduce I&E at IPEC. Based on the comparison of potential benefits and costs, including sensitivity cases and Monte Carlo uncertainty analysis, we reach the following conclusions.

- Neither CWWS nor Cooling Towers passes a social benefit-cost test, because their potential social costs are far greater than their potential social benefits, although we understand Entergy has communicated its commitment to CWWS despite this conclusion.

- Cooling Towers are dominated by CWWS, because Cooling Towers would have significantly higher costs than CWWS but significantly lower benefits. The benefits of Cooling Towers are particularly low when air permitting issues are taken into account (because IPEC would have to operate with once-through cooling for most of the year), but Cooling Towers are dominated by CWWS even when air permitting issues are not taken into account, as discussed in Appendix H.

- These conclusions do not change if one considers factors that have been excluded from the quantitative assessments. We review the relevant categories of non-quantified costs and benefits and determine that the inclusion of any of these categories in the quantitative analysis would not change the overall conclusions that costs would far exceed benefits for both alternatives and that Cooling Towers are dominated by CWWS because of higher costs and lower benefits.

- These conclusions are also robust to sensitivity cases and Monte Carlo uncertainty analysis. In particular, even the sensitivity case with "all favorable" assumptions (leading to lower costs and higher benefits for each alternative than the base case assumptions) produced net costs for both CWWS and Cooling Towers rather than net benefits. Moreover, the Monte Carlo uncertainty analysis produced net costs for both alternatives for all draws, and Cooling Towers had lower benefits than CWWS for all draws.

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Appendix A: Electricity Price Forecasts

This appendix describes the methodology used to estimate monthly wholesale electricity prices from 2015 to 2035 for a region that consists of New York City and Westchester County, New York. As explained in Chapter III, wholesale electricity prices are used to value the social benefits of the increase in power output at IPEC due to the installation and operation of CWWS and Cooling Towers. Wholesale electricity prices are an appropriate measure of the real-resource costs or benefits of small changes in power output because they reflect the marginal cost of supplying an additional unit of electricity to the grid.

This appendix provides background on the New York State wholesale electricity markets, describes the methodology for developing electricity price projections, and presents the resulting forecasts.

A. Background on New York State Wholesale Electricity Markets

Until late in the twentieth century, electricity throughout the United States was generated and distributed primarily by vertically-integrated utilities that had an exclusive franchise within a given area and were subject to rate-of-return (cost-of-service) price regulation. Many states still rely on that traditional regulatory structure.

Starting in the 1990s, New York and several other states moved to a vertically-disintegrated system in which regulated investor-owned utilities ("IOUs") buy most of the power they need to serve their customers' demand from wholesale generating companies, such as Entergy, with the prices being determined by the market. These purchases can occur through spot markets administered by "Independent System Operators," such as the New York Independent System Operator ("NYISO"), that manage markets in which generators bid to provide power to the system. The NYISO was established in 1999 (NYSEPB 2009a, p. 16), and the electricity from IPEC is sold in power markets organized by the NYISO.

The NYISO is responsible for the operation of New York's nearly 11,000 miles of high-voltage transmission and the dispatch of over 500 electric power generators. In addition, the NYISO administers bulk power markets that trade an average of $7.5 billion in electricity and related products annually (NYISO 2013). The NYISO coordinates dispatch and sets wholesale electricity prices (which differ from retail electricity prices primarily because they do not include transmission and distribution costs) through hourly uniform-price auctions using bids from suppliers and demand-response resources.

The two main components of the NYISO wholesale electricity market are: (1) energy markets, and (2) a capacity market.[26]

[26] The energy and capacity prices are the largest components of wholesale electricity prices, but various "ancillary services" are also required to support the reliable operation of the transmission system. The two most important ancillary services are reserves and regulation (NYISO 2013). Reserves are generating units that are available to provide fast ramping power in the event of any unforeseen occurrences. "Spinning reserves" are already generating electricity, but have the capability to generate more if needed. "Non-spinning reserves" are off-line

1. NYISO Energy Markets

The NYISO runs a day-ahead market and a real-time market for electricity. The day-ahead market provides generators with advanced notice of power requirements and incentive to perform as scheduled. The real-time market enables the NYISO to efficiently balance the system because conditions can change from the time the day-ahead market is run. The NYISO also handles the scheduling of direct transactions between buyers and sellers—known as bilateral transactions—which account for roughly half of the energy settled in the day-ahead market (NYISO 2013).

These energy markets ensure reliability and least-cost generation through the use of clearing price auctions and competitive bid structures. As the New York State Energy Planning Board explains in its 2009 Energy Plan:

> Using the bids of both suppliers and demand-response resources, the NYISO software economically commits and dispatches resources at the least cost consistent with transmission and other system constraints using a uniform-price auction format. Essentially, this means that the market clearing price paid to all suppliers is based upon the marginal cost of the last unit chosen to serve load. Under this arrangement, suppliers, absent market power, have every incentive to bid into the market their marginal costs of production, because if they bid below it they may run at a loss and if they bid above it they may not be selected for dispatch and will neither run nor be paid. This results in the system being dispatched in the most efficient manner that minimizes total production costs, thus providing power to consumers at the lowest possible price (NYSEPB 2009a, p. 17).

The result is a series of Locational Based Marginal Prices ("LBMP"), which are equal to the cost of energy production plus the transportation (losses and congestion) cost at each location. Figure A-1 displays the various "load zones" across the New York, for which LMBPs differ based primarily on the cost of providing sufficient electricity to each zone to satisfy demand (NYISO 2013).

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units that can start providing generation to the grid relatively quickly (NYISO 2013). Because load and generation must be kept in constant balance on the grid, short-term changes in electricity use can affect the stability of the power system. NYISO relies on "regulating resources" to rapidly adjust their output or consumption in response to constantly changing load conditions, and thus keep load and generation in balance (NYISO 2013).

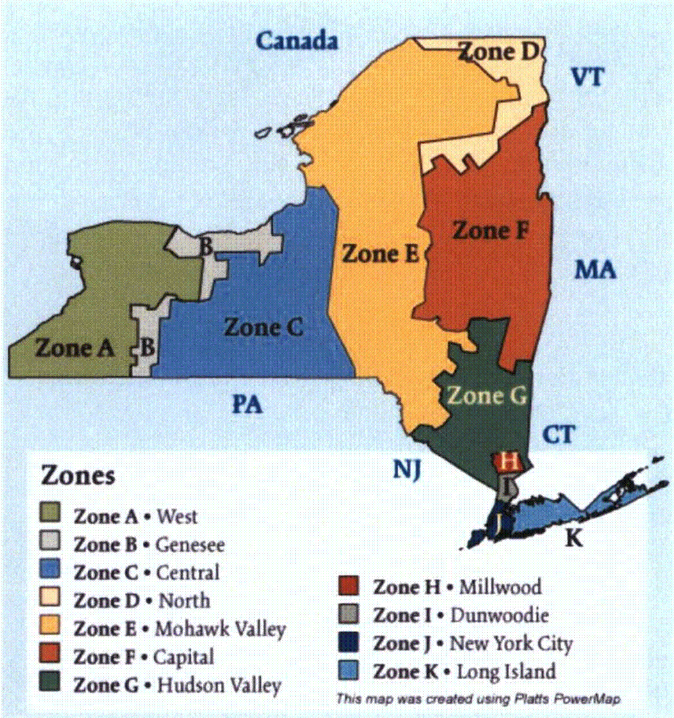


Figure A-1. NYISO Load Zones

As a result of this competitive bid structure, the temporal variations in demand that characterize electricity markets cause different types of units to be dispatched at different times. During off-peak periods when demand is relatively low, typically only those units with relatively low marginal costs (including IPEC and other nuclear units) operate. During peak periods, when demand is relatively high, units with higher marginal costs also operate to satisfy demand.

The market price in each period is the system's marginal cost, which is calculated as the marginal cost of the most expensive unit added to meet demand. Small changes in net power output at IPEC thus would lead to changes in power generated at the "marginal unit" at a cost equal to the market price of power during the relevant period.

2. NYISO Capacity Market

NYISO also administers a capacity market in which companies supplying power to customers (i.e., load-serving entities, or "LSEs") can purchase the capacity required to meet their capacity obligations. The goal of the capacity market is to ensure that sufficient resources are available to meet projected load on a long-term basis and encourage the development and maintenance of sufficient generation capacity in New York State.

Capacity providers (i.e. power plants) make their generation capacity available to load-serving entities (that is, they "bid into" the capacity market), and in return receive payments from LSEs. In effect, LSEs pay the power plants for the assurance that the power plants could provide power if called upon. The presence of capacity markets thus provides incentives for investment in generation capacity so that there will be capacity sufficient to meet load, even in times of peak electricity demand. The capacity market provides a mechanism for generation units that operate only in peak demand periods—which typically have high marginal costs and relatively low fixed costs—to recover their fixed costs.

To set capacity prices, NYISO uses a demand curve relating capacity and price that incorporates a "reserve margin" by which generation capacity should exceed projected peak load. Small changes in generation capacity at IPEC would be valued based upon prices in the NYISO capacity market.

The NYISO also supports various "demand response" programs designed to encourage reductions in electricity usage based on economic or reliability signals (NYISO 2013). Similar to capacity markets, the objective of these programs is to ensure that resources are available to meet the long-term demand for electricity in New York.

B. Electricity Price Projections

Our analysis assumes that the small changes in electricity generation due to CWWS would not affect electricity prices and thus overall electricity demand would be unchanged. Thus, the change in IPEC generation due to the installation and operation of CWWS at IPEC would be balanced by a change in electricity output from other generators. The installation of Cooling Towers at IPEC would require a sustained capacity outage that would trigger a temporary price response from the market. We would expect that prices during the outage would temporarily rise to a level equal to that if IPEC were retired. This temporary electricity price jump would not affect the trajectory of electricity prices over time and prices would return to lower levels once the installation is complete. We make the conservative assumption to ignore this temporary price jump that would increase total costs to the system, since it will not affect our results in the long-run. We estimate the social costs of changes in net electricity output at IPEC using the marginal cost of replacement energy on the grid. As explained above, the real-resource costs of supplying an additional unit of electricity to the grid can be estimated using the wholesale prices of electricity. This section describes our methodology for estimating wholesale electricity prices over the relevant period, which is from 2013 to 2035. Although wholesale energy prices are set hourly, it is sensible to provide price projections for more aggregated time periods. As discussed below, we develop average monthly price projections.

1. Overview of Methodology

We develop monthly wholesale electricity price projections using data from the U.S. Energy Information Administration's ("EIA") National Energy Modeling System ("NEMS") and the NYISO. From both sources, we gather data on electricity prices for a region consisting of New York City and Westchester County, New York. The NEMS data consist of annual projections of wholesale electricity prices (including generation, capacity and ancillary services) for the years 2013 to 2035, and are the basis of our price projections. The NYISO data are monthly historical wholesale electricity prices from 2007 and 2012, which we use to estimate the average variations in prices by month over the course of the years.

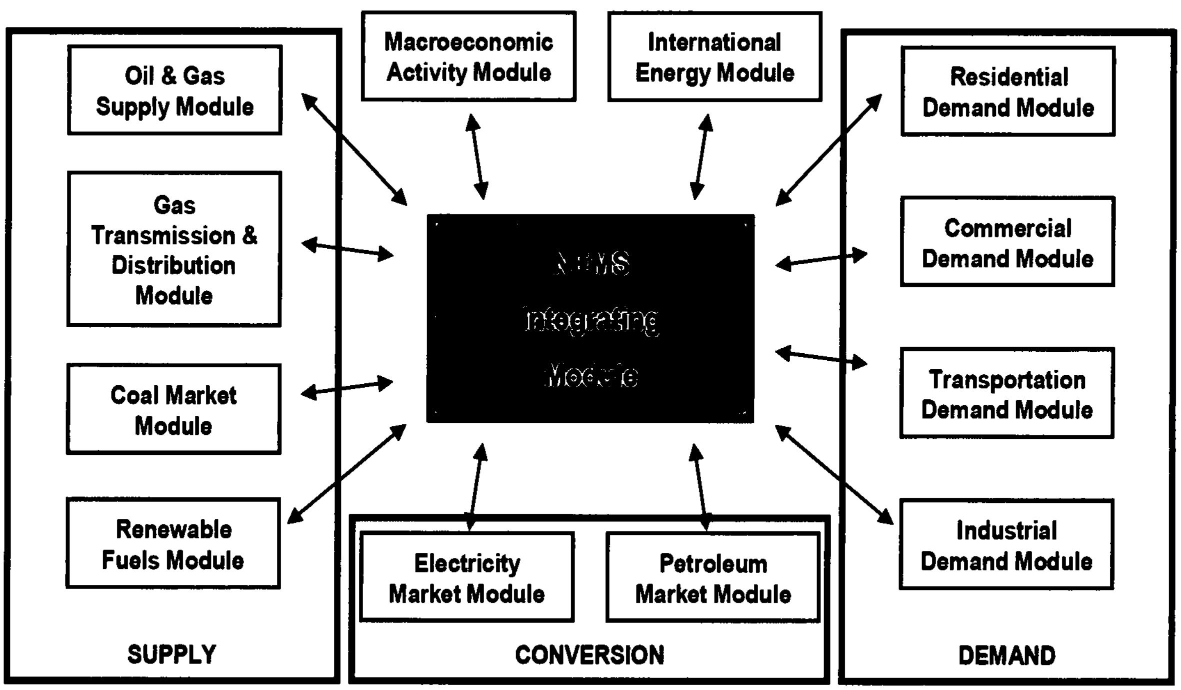
2. Overview of the National Energy Modeling System (NEMS)

Annual electricity price forecasts were obtained from the *Annual Energy Outlook ("AEO") 2013* (EIA 2013). This report, published annually by the EIA, uses NEMS to form baseline projections for national and regional energy prices and quantities. NEMS is a detailed energy and economic model developed and maintained by the EIA Office of Energy Analysis to provide projections of domestic energy-economy markets in the long term and to perform policy analyses requested by decision-makers in the White House, Congress, Department of Energy, and other government agencies. The EIA projections are used by analysts and planners in government agencies and other outside organizations, including the New York State Energy Research and Development Authority ("NYSERDA").

NEMS models the supply and demand of energy and other markets at regional levels, taking into account interactions among regions. The level of regional detail for the end-use demand modules is the nine Census divisions used by the United States Census Bureau. Other regional structures include production and consumption regions specific to oil, natural gas, and coal supply and distribution, the North American Electric Reliability Corporation ("NERC") regions and sub-regions for electricity, and the Petroleum Administration for Defense Districts ("PADDs") for refineries.

For each fuel and consuming sector, NEMS balances the energy supply and demand, accounting for the economic competition between the various energy fuels and sources. NEMS is organized and implemented as a modular system, as shown in Figure A-2 below.

Figure A-2. Structure of NEMS



Source: Adapted from EIA (2012)

The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes a macroeconomic module and an international module. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data such as economic activity, domestic production, and international petroleum supply availability.

The integrating module of NEMS controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data storage location. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules. This modularity allows use of the methodology and level of detail most appropriate for each energy sector. NEMS solves by calling each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Other variables are also evaluated for convergence such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

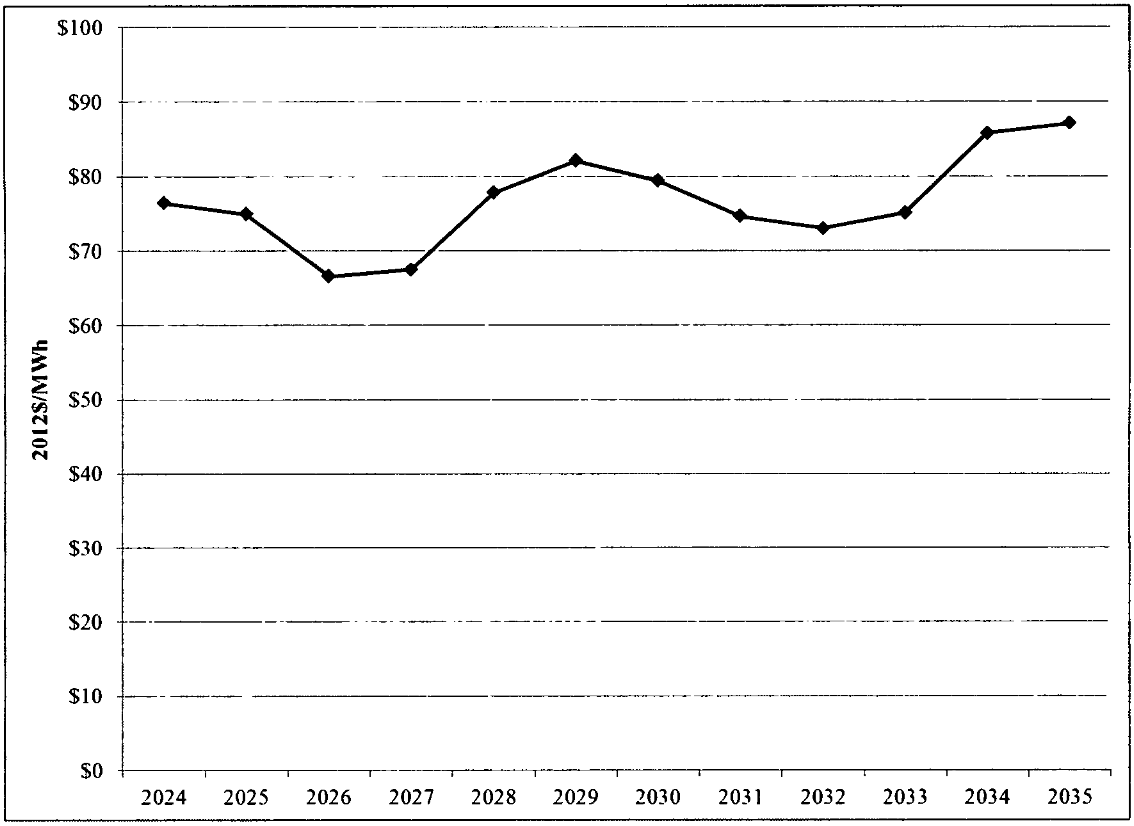
The Electricity Market Module has three primary "submodules": (1) capacity planning; (2) fuel dispatching; and (3) finance and pricing. The finance and pricing submodule determines transmission costs as well as regional electricity prices. This submodule uses capital costs, fuel costs, macroeconomic parameters, environmental regulations, and load shapes to estimate generation costs for each technology.

3. NEMS Annual Price Projections

NEMS divides New York State into three regions: (1) New York City (NYC) / Westchester; (2) Long Island; and (3) Upstate New York. We use the NYC / Westchester region prices because generation affected by changes at IPEC will likely be supplied to that region.

Figure A-3 displays the NEMS projections of average annual wholesale electricity prices (in constant 2012 dollars) for the NYC / Westchester region. The average annual NYC / Westchester wholesale electricity price is projected to be $87/MWh (in 2012 dollars) in 2035.

Figure A-3. Projected Average Annual New York City / Westchester County Wholesale Electricity Prices



Source: NEMS (EIA 2013)

4. Monthly Electricity Price Variability

Electricity prices can vary substantially on a month-to-month basis, due largely to changes in electricity demand during different seasons of the year. However, the NEMS model provides only annual price projections. To our knowledge, there are no comparable forecasts of New York wholesale electricity prices available on a monthly basis. We therefore use historical data from the NYISO to estimate the likely variability in electricity prices by month over the course of the year.

In particular, we calculate historical ratios of average monthly prices to average annual prices for the NYC / Westchester region. We use 2007 to 2012 monthly prices from NYISO zones H, I and J[27] to calculate these ratios. As shown in Table A-1, the ratios of average monthly to average annual wholesale electricity prices range from 0.79 in November to 1.24 in July and August. These ratios show that electricity prices are generally higher in the summer and winter when demand is high and lower in the fall and spring when demand is relatively low. Thus, a change in

[27] NYISO Zones H, I, and J roughly correspond to the EIA NYC / Westchester region. To estimate a composite price for these three zones, we weighted the prices by the monthly load in each Zone.

electricity output at IPEC during the summer or winter months would result in a higher societal cost or benefit than one that occurred during the fall or spring.

Table A-1. Ratios of Monthly to Annual Electricity Prices in NYISO Zones H, I and J

Month	Ratio
January	1.13
February	1.04
March	0.92
April	0.95
May	1.03
June	1.18
July	1.24
August	1.04
September	0.90
October	0.79
November	0.81
December	0.98

Note: Ratio of average monthly to average annual electricity prices in NYISO Zones H, I and J.
Source: NERA calculations based on NYISO historical data (NYISO 2013)

5. Electricity Price Projections

The final step of our methodology is to combine the annual wholesale electricity price projections from NEMS with the estimates of monthly price variability from the NYISO data. We multiply the annual wholesale electricity prices by the ratios of monthly price variability to obtain estimates of monthly wholesale electricity prices from 2024 to 2035. Table A-2 and Figure A-4 provide information on the resulting average monthly wholesale electricity price projections for NYC / Westchester in 2012 dollars.

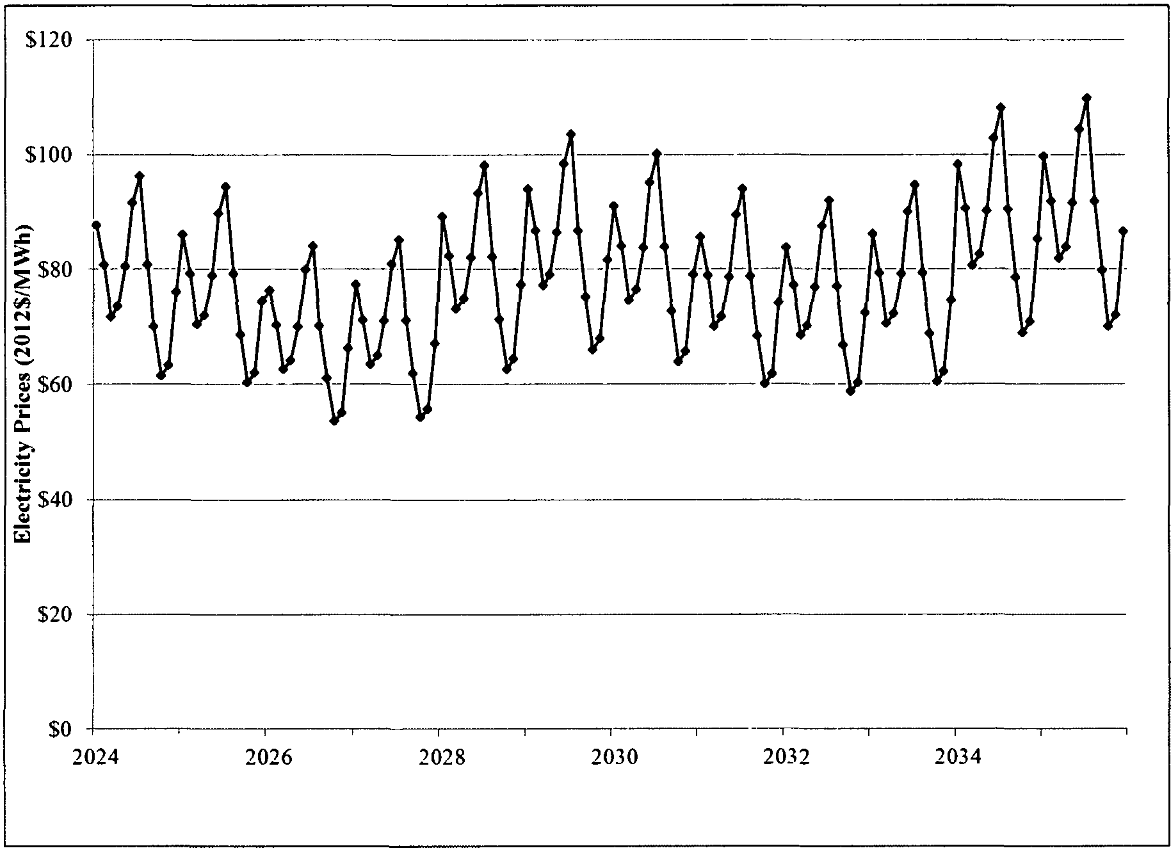
Table A-2. Monthly NYC / Westchester Wholesale Electricity Price Projections (2012$/MWh)

	2025	2030	2035
January	84.37	89.42	97.98
February	77.78	82.43	90.32
March	69.20	73.33	80.36
April	70.87	75.10	82.29
May	77.53	82.16	90.03
June	88.24	93.51	102.47
July	92.80	98.34	107.76
August	77.70	82.34	90.23
September	67.47	71.50	78.35
October	59.26	62.80	68.81
November	60.92	64.56	70.74
December	73.17	77.55	84.98

Note: Prices have been converted from 2011 dollars in the EIA data to 2012 dollars using the GDP implicit price deflator from the U.S. Bureau of Economic Analysis.

Source: NERA calculations based on NYISO historical data (2013) and EIA forecasts (2013)

Figure A-4. Monthly NYC/Westchester Wholesale Electricity Price Projections (2012$/MWh)



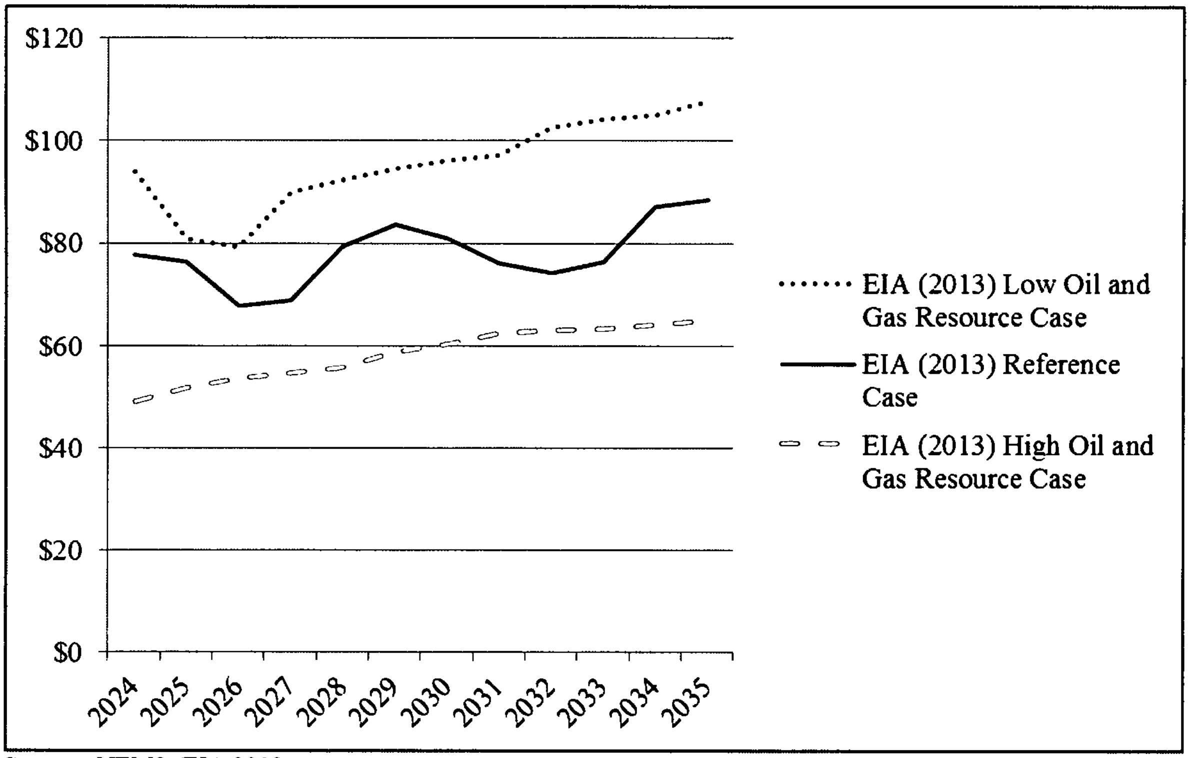
Source: NERA calculations as explained in text

C. Electricity Price Uncertainty

Any projection of electricity prices is subject to some uncertainty. We test whether our conclusions are robust to this uncertainty using alternative assumptions about future wholesale electricity prices.

Our sensitivity cases for wholesale electricity prices are informed by two side case projections from EIA (2013)—the Low Oil and Gas Resource case and the High Oil and Gas Resource case. These side cases represent scenarios in which the supply of natural gas and oil is lower or higher than in the EIA (2013) Reference case (which we use to construct our base case projections); lower supply of these fuels leads to higher electricity price projections and vice versa for higher supply. Natural gas supply specifically is a key determinant of electricity prices, so the variation in these side case projections provides a plausible spread of future wholesale electricity prices.

Figure A-5. Projected Average Annual New York City / Westchester County Wholesale Electricity Prices



Source: NEMS (EIA 2013)

Figure A-3 shows these EIA (2013) side case projections from 2024 to 2035. The largest percentage differences from the Reference case projection are -37 percent in 2024 and +43 percent in 2036. In order to reflect variation of this magnitude while retaining the general shape of the Reference case projection, we assume prices are 40 percent below base case price projections in our "low" price sensitivity case and 40 percent above base case prices in our "high" price sensitivity case.

D. References

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Appendix B: Commercial and Recreational Harvest Percentages

This appendix describes our methodology for allocating theoretical increases in harvest between commercial and recreational fisheries. We estimated commercial-recreational percentages for the four species for which ASAAC (2013) estimated theoretical increases in harvest:

1. Striped bass (which accounts for the vast majority of total increases in harvest, as shown in Chapter IV);
2. White perch;
3. American shad; and
4. *Alosa* sp. (alewife and blueback herring).

Our methodology for allocating the theoretical increase in harvest between recreational and commercial fisheries is based on historical information on commercial and recreational landings. In particular, we use data from the National Marine Fisheries Service (NMFS) of the National Oceanic and Atmospheric Administration (NOAA) on commercial and recreational harvest landings for New York (including the Hudson River up to the Federal Dam at Troy) and the Atlantic coast over the ten-year period from 2003 to 2012 (most recent data) to calculate average commercial and recreational percentages over this historical period. We then use the historical percentages as estimates of the likely future commercial and recreational percentages.

The following sections provide background on the management of the four species as well as the information on commercial and recreational landings that we use to develop our estimates. The final section provides a summary of our conclusions.

A. Background on Regulation of Commercial and Recreational Fisheries

Three of the four analyzed species (striped bass, American shad, and *Alosa*) are managed by the Atlantic States Marine Fisheries Commission ("ASMFC") and the New York State Department of Environment Conservation ("NYSDEC"). As discussed in Appendix C, management of fish species is motivated by concerns related to "overfishing," since fish have historically been common property resources.

1. Summary of Atlantic and New York Restrictions

The following table summarizes the restrictions on commercial and recreational fishing at the Atlantic and New York levels.

Table B-1. Restrictions on Commercial and Recreational Fisheries

	Atlantic		New York	
	Commercial	**Recreational**	**Commercial**	**Recreational**
Striped bass	Banned in several states, quotas for other states, size limits, season restrictions, gear restrictions	Size limits, daily bag limits, season restrictions, gear restrictions	Banned in Hudson, state quota (828,293 lbs), size limit (24"-36"), season restriction (July 1 to Dec 15), gear restrictions (e.g., no gill nets in some areas)	Size limits (e.g., 18" min in Hudson), daily bag limits (e.g., 1 in Hudson), gear restrictions (angling or spearing only), season restrictions (e.g., Apr 15 to Dec 15 in Hudson)
American shad	States must have sustainable fishery plans	States must have sustainable fishery plans	Banned	Banned
Alosa sp.	States must have sustainable fishery plans	States must have sustainable fishery plans	Banned except for Hudson and Federal ocean waters with Federal permit, season restriction in Hudson (March 15 to June 15), state permit required in Hudson	Banned except in Hudson, season restriction (March 15 to June 15), daily bag limit (10 per day), gear restrictions (angling or personal-use nets), state permit required

Sources: ASMFC (2009, 2010, 2013), NYSDEC (2011, 2013)

2. Implications of the Restrictions

These regulations could affect the extent to which the ASAAC calculations of theoretical harvest gains would translate into actual increases in fishery harvests. In the case of American shad, for example, additional harvest would not result in any additional harvest in New York because of the ban on both commercial and recreational American shad fishing.

The situation for striped bass is most important because striped bass represent more than 95 percent of total theoretical additional harvest due to CWWS or Cooling Towers at IPEC. New York has a current quota of about 828,000 pounds (or about 375 metric tons) for commercial striped bass harvest. If the quota were binding, the additional theoretical harvest due to CWWS or Cooling Towers at IPEC would not result in additional actual commercial harvest in New York. As noted below, however, the landings data suggest that the commercial quota in New York has not been binding (i.e., landings have been below the quota) and thus that the quota will not be binding in the future. Thus, we assume that additional commercial harvest of striped bass would occur as a result of the harvest benefits of CWWS or Cooling Towers. With regard to the recreational catch, the recreational limits (size, gear, and season) could mean that the likely additional recreational harvest is less than the theoretical harvest estimated by ASAAC (2013).

B. Commercial Landings Data

Table B-2 presents NMFS data on commercial landings weights (in metric tons) from 2003 to 2012 in New York and the Atlantic coast.[28] Note that commercial landings for striped bass have been relatively steady in both New York and the Atlantic coast, but commercial landings for white perch, American shad, and *Alosa* have fluctuated sharply in New York and have generally been steadier in the Atlantic coast. Note also that the annual striped bass landings are less than the current quota in every year except 2011.

Table B-2. Commercial Landings (metric tons)

	Striped Bass		White Perch		American Shad		Alosa sp.	
	New York	Atlantic	New York	Atlantic	New York	Atlantic	New York	Atlantic
2003	355.9	3,213.5	4.2	1,001.7	67.2	684.9	9.3	679.9
2004	338.6	2,850.4	0.5	447.7	6.8	515.6	6.6	604.1
2005	322.4	3,577.0	0.4	853.3	2.0	308.0	2.6	332.4
2006	312.3	2,978.5	1.1	454.9	4.2	245.8	5.0	683.6
2007	331.7	3,326.1	0.2	596.4	22.7	340.7	12.8	415.9
2008	296.2	3,389.3	0.3	635.9	10.3	221.7	9.5	644.1
2009	338.9	3,416.4	0.9	882.1	4.7	113.7	5.3	747.2
2010	339.1	3,444.7	0.1	982.2	1.2	260.3	5.7	1,041.3
2011	388.0	3,294.9	0.7	1,167.9	1.3	283.4	6.8	620.0
2012	310.2	3,253.9	2.5	970.9	1.5	289.1	0.1	750.6
Total	3,333.3	32,744.7	10.9	7,993.0	121.9	3,263.2	63.7	6,519.1

Source: NMFS (2013a)

C. Recreational Landings Data

Table B-3 presents recreational landings weights (in metric tons) from 2003 to 2012 in New York and the Atlantic coast. Note that recreational landings of white perch, American shad, and *Alosa* in New York are unavailable in most years.

[28] In the NMFS data, the Atlantic coast includes Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia, North Carolina, South Carolina, Georgia, and Florida's east coast.

Table B-3. Recreational Landings (metric tons)

	Striped Bass		White Perch		American Shad		Alosa sp.	
	New York	Atlantic	New York	Atlantic	New York	Atlantic	New York	Atlantic
2003	1,546.6	10,411.3	1.5	545.1	-	-	-	13.2
2004	1,690.6	13,649.0	6.8	387.8	-	0.0	-	50.3
2005	2,511.8	13,808.8	-	453.3	-	4.2	-	2.6
2006	2,734.5	14,181.3	-	633.4	-	35.9	-	0.5
2007	3,589.7	12,288.4	-	716.2	-	-	-	6.5
2008	4,955.7	13,901.5	-	946.4	-	0.2	-	20.6
2009	2,270.1	10,413.4	-	175.5	-	0.7	-	8.1
2010	3,173.9	10,458.1	-	625.5	-	0.0	-	3.6
2011	4,068.7	12,391.0	-	443.3	-	-	-	0.7
2012	2,942.1	8,858.8	-	430.4	-	1.9	-	1.7
Total	29,483.6	120,361.5	8.3	5,356.8	-	42.9	-	107.8

Note: "-" denotes that no landings data are available.
Source: NMFS (2013b)

D. Commercial and Recreational Harvest Percentages

Table B-4 presents commercial percentages for each species in each year based on the commercial and recreational landings weights provided above. Percentages for white perch, American shad, and *Alosa* are only calculated for the Atlantic coast because sufficient data are not available for New York.

Table B-4. Commercial Percentages

	Striped Bass		White Perch		American Shad		Alosa sp.	
	New York	Atlantic	New York	Atlantic	New York	Atlantic	New York	Atlantic
2003	19%	24%	-	65%	-	100%	-	98%
2004	17%	17%	-	54%	-	100%	-	92%
2005	11%	21%	-	65%	-	99%	-	99%
2006	10%	17%	-	42%	-	87%	-	100%
2007	8%	21%	-	45%	-	100%	-	98%
2008	6%	20%	-	40%	-	100%	-	97%
2009	13%	25%	-	83%	-	99%	-	99%
2010	10%	25%	-	61%	-	100%	-	100%
2011	9%	21%	-	72%	-	100%	-	100%
2012	10%	27%	-	69%	-	99%	-	100%
Average	10%	21%	-	60%	-	99%	-	98%

Note: "-" denotes that commercial-recreational splits are not calculated for this range.
Source: NERA calculations as explained in text

We based our estimates of the commercial-recreational splits on the averages over the period from 2003 to 2012 shown in the bottom row of the table above. We based our split for striped bass on landings data for New York for two reasons:

1. *Range*. As noted in ASAAC (2013), the majority of the additional striped bass harvest from reduced I&E at IPEC would most likely occur in New York.

2. *Data availability*. NMFS provides complete data on striped bass commercial and recreational landings for New York.

For the other three species (white perch, American shad, and *Alosa*), we based our split on landings data for the Atlantic coast. Although the harvests of these other species may be concentrated in and around New York, the data available for New York is not sufficient to provide reliable estimates of percentages. We do not expect the lack of New York data for these other species to have a substantial effect on the benefit estimates because these other three species account for a very small percentage of the theoretical additional harvest.

Table B-5 summarizes the commercial and recreational percentages we used for the four species. Note that striped bass, the largest source of lost fishery harvest, is only 10 percent commercially harvested, a much lower percentage than the other species.

Table B-5. Commercial and Recreational Percentages by Species

	Striped Bass	White Perch	American Shad	Alosa sp.
Commercial	10%	60%	99%	98%
Recreational	90%	40%	1%	2%
Total	100%	100%	100%	100%

Source: NERA calculations as explained in text

E. Harvest Percentage Uncertainty

There is some uncertainty about what recreational and commercial harvest percentages will be in future years. As part of our uncertainty analysis, we use 2003-2012 NMFS (2013a, 2013b) historical data on fish harvests to develop alternative assumptions about harvest percentages.

To test the sensitivity of our conclusions to alternative harvest percentages, we created "low" and "high" commercial harvest percentage cases by using the minimum and maximum annual commercial harvest percentage for each species in the last ten years. Table B-2 shows these minimum and maximum values.

Table B-6. Base, Low, and High Commercial Harvest Percentages by Fish Species

	Striped Bass	White Perch	American Shad	Alosa sp.
Base	10%	60%	99%	98%
"Low" (Minimum)	6%	40%	87%	92%
"High" (Maximum)	19%	83%	100%	100%

Source: NMFS (2013a, 2013b); NERA calculations as explained in text.

Monte Carlo analysis requires that we also assume a distribution of harvest percentages. Our base case harvest percentages are the landings-weighted average of annual harvest percentages from 2003-2012. For our Monte Carlo analysis, we assume that harvest percentages for each species are distributed uniformly; uniform distributions, like harvest percentages, are bounded below and above. We use the base case harvest percentage as the mean of each distribution and the landings-weighted sample standard deviation of annual harvest percentages as the standard deviation of each distribution.

The mean and standard deviation of a uniform distribution imply minimum and maximum values. In two cases—American shad and *Alosa* sp.—the implied maximum value of the uniformly distributed commercial harvest percentage was over 100 percent. In the Monte Carlo simulation, we replaced any random draws over 100 percent with 100 percent. Table B-7 shows the parameters of the uniform distributions for each fish species.

Table B-7. Uniform Distribution Parameters for Commercial Harvest Percentages by Fish Species

	Striped Bass	White Perch	American Shad	Alosa sp.
Uniform Mean	10%	60%	99%	98%
Uniform St Dev	4%	14%	4%	2%
Uniform Minimum	4%	36%	92%	94%
Uniform Maximum	16%	84%	105%*	102%*

*Random draws over 100 percent in Monte Carlo simulations are replaced with 100 percent.
Source: NMFS (2013a, 2013b); NERA calculations as explained in text.

F. Summary

We base our estimates of commercial and recreational percentages for striped bass on landings data for New York State. We base our estimates for the other three species on landings data for the Atlantic region because New York data are not available. These estimates all presume that existing restrictions on the commercial and recreational harvest of these species are not binding—in which case the additional theoretical harvest may not be reflected in additional actual harvest—and that the historical data on commercial and recreational harvest provide appropriate estimates of future percentages.

G. References

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Appendix C: Commercial Fishing Benefits

This appendix describes the methodology and data used to estimate the commercial fishing benefits associated with reduced I&E due to CWWS or Cooling Towers at IPEC. We begin with an overview of our methodology, which is consistent with EPA 2011 (Chapter 6). The following section provides information on the data we used to develop our empirical estimates. The final section discusses certain caveats to this methodology and their potential implications for our commercial fishing benefits estimates.

A. Methodology for Estimating Commercial Fishing Benefits

1. Overview of Commercial Fishing Benefits

The total economic gain from reduced I&E for commercially harvested fish species is equal to the sum of changes in producer and consumer surplus. The basic approach to estimating benefits consists of the following three steps (adapted from Bishop and Holt 2003, as referenced in EPA 2011).

1. Assess the net welfare changes for fish consumers due to changes in fish harvest and the corresponding change in fish prices;

2. Assess the net welfare changes for fish harvesters due to changes in fish harvest, fish prices and the cost of harvesting;

3. Calculate the net social benefits due to increases in commercial fish harvest as the sum of changes in consumers and producers surplus.

These calculations presume that the commercial fishery is regulated since, as explained in the final section of this appendix, in an unregulated fishery, the gains to producers from increased commercial catch would be expected to be zero.

Figure C-1 provides a graphical overview of the potential changes in consumer and producer surplus due to a change in commercial fishing harvest. The graph presumes that commercial fish harvest increases from F1 to F2. If demand curves are downward-sloping (as is generally assumed), increases in fish populations would lead to decreases in fish prices. These price changes would have implications for both producers and consumers.

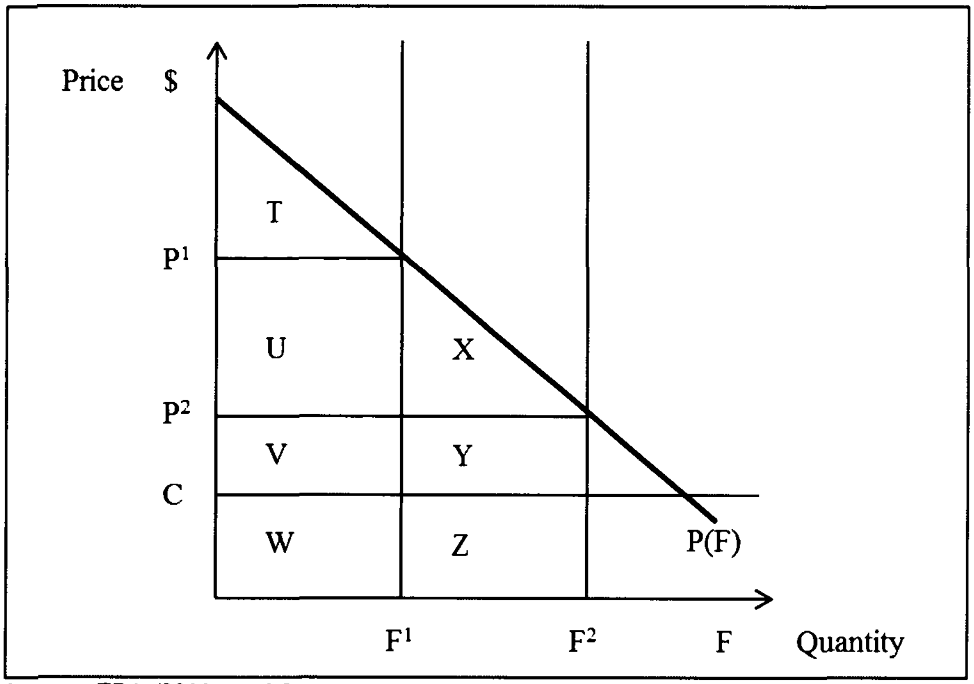
The following are the potential gains to fish consumers and harvesters as well as the implications for total gains in consumer and producer surplus.

- *Fish consumers.* Fish consumers gain consumer surplus if prices decrease. The figure shows price decreasing from P^1 to P^2. At P^1, the original consumers' surplus is equal to T and the change in consumers' surplus due to the decrease in price is equal to U + X.

- *Fish harvesters.* Fish harvesters gain from increases in revenues net to changes in costs. The original harvesters' surplus is equal to U + V, based upon revenues equal to U+V+W and costs of W. The reduction in price leads to a loss to fish harvesters equal to U (which represents a transfer from harvesters to consumers). The increased harvest leads to a gain in revenue of Y + Z and a net gain in harvested surplus equal to Y.

- *Net potential increase for fish consumers and harvesters.* The net gain in potential consumers and producers surplus due to the change in harvest can be represented by the sum of X (gain to consumers from additional catch) and Y (net gain to harvesters taking into account the added costs of the additional catch).

- *Implications of no price decrease.* The gains to consumers depend upon the increased harvest leading to lower fish prices. If the increased harvest for a given species is small relative to the size of the market, the market price would not change. In that case, the net gain would accrue to fish harvesters and would be equal to the net revenues from the additional catch (i.e., added revenues minus added costs, or Y in the diagram). As discussed below, this is the likely situation for 316(b) commercial fishing benefits.



Source: EPA (2011), p. 6-2

Figure C-1. Fishery Market Model

2. Application of Methodology to 316(b) Commercial Fishing Benefits

EPA (2011) provides an application of the methodology outlined above in its assessment of regional commercial fishing benefits for the proposed 316(b) Replacement Rule. The following is a summary of the nature of these calculations.

1. *Estimate the changes in commercial harvests due to reduced I&E.* EPA assumes a linear relationship between stock and harvest (p. 6-1). In other words, the percentage increase in

commercial harvest is assumed to be the same as the percentage increase in commercial fish due to reduced I&E.

2. *Estimate the changes in commercial prices due to the change in fish populations.* EPA estimates the potential price changes due to I&E for individual fish species in various regions and concludes that they are small for all of the relevant species and fisheries (between 0.13 and 2.1 percent). Thus, for purposes of estimating commercial fishing gains, EPA assumes that the commercial fish prices would not change due to increases in commercial fish populations from reduced I&E (p. 6-4).

3. *Estimate the change in consumer surplus.* As noted above, consumers would benefit only if fish prices change. Since prices do not change, the change in consumer surplus is necessarily equal to zero as in EPA's calculations.

4. *Estimate the change in producer surplus.* EPA notes that, in theory, producer surplus is equal to normal profits (total revenue minus fixed and variable costs) minus the opportunity cost of capital. EPA determines that the opportunity cost of capital is sufficiently small (less than 3 percent of producer surplus) that it can reasonably be assumed to equal zero (p. 6-4). Producer surplus is thus equal to "normal profits," or gross revenues minus variable costs. Gross revenues are estimated based on the changes in commercial prices (which, as noted above, are assumed to be constant) and the changes in commercial harvest. Because variable costs (labor, fuel, etc.) vary directly with the level of landings, EPA assumes that the changes in producer surplus are equal to certain proportions of the change in gross revenues. These proportions are referred to as the "Net Benefits Ratios," which differ by region and species, and range from 0.15 to 0.85 (p. 6-4).

5. *Estimate commercial fishing benefits.* Commercial fishing benefits are equal to the sum of the changes in producer surplus and the changes in consumer surplus. The changes in consumer surplus are assumed to equal zero, so commercial fishing benefits are equal to the changes in producer surplus (p. 6-1).

B. Estimating Commercial Fishing Benefits at IPEC

Following the methodology outlined above, this section summarizes our methodology for estimating commercial fishing benefits of CWWS and Cooling Towers at IPEC.

1. Changes in Commercial Harvest

We calculate changes in commercial harvest based on estimates of the total theoretical additional harvest and the percentage of that additional harvest that is caught by commercial fisherman. The estimates of annual theoretical additional harvest due to CWWS and Cooling Towers at IPEC are from ASAAC (2013) and are described in detail in Chapter IV. The estimates of the proportions attributed to commercial fishing are based on commercial and recreational landings data from NOAA, and is described in detail in Appendix B. Again, following EPA's methodology outlined above, we assume a linear relationship between fish stock and harvest.

2. Prices of Commercially Harvested Fish

Data on commercial fish prices are needed to estimate the changes in producer and consumer surplus due to reduced I&E.

a. Data on Commercial Fish Prices

We used *ex-vessel* prices (*i.e.,* prices that fishermen receive at the dock for their catch) to estimate the value of fish caught commercially similar to EPA in its proposed 316(b) Replacement Rule (EPA 2011). Annual average values for the ex-vessel prices of various commercially-fished species can be calculated using data available from the National Marine Fisheries Service (NMFS). NMFS provides state- or region-level data on annual landings (kg) and total sales values (nominal dollars). Prices calculated from these data therefore differ by location, time period and species. Although it would be desirable to use projected future prices—since commercial benefits, if any, from an implemented fish-protection alternative could extend into the future for several decades—such projected prices are not available.

We estimated commercial prices for the four species for which ASAAC estimated theoretical increases in harvest:

1. Striped bass (which accounts for the vast majority of total increases in harvest, as shown in Chapter IV);
2. White perch;
3. American shad; and
4. *Alosa* sp. (alewife and blueback herring).

We obtained NMFS data on commercial landings weight and total value for these species for the 10-year period from 2003 to 2012 (NMFS 2013). We evaluated two alternative ranges for each species: New York and the Atlantic coast. Appendix B presents commercial landings weights for the three species from 2003 to 2012 in New York and the Atlantic coast. As noted in Appendix B, we used New York data to estimate the commercial-recreational split for striped bass and Atlantic coast data for the other species.

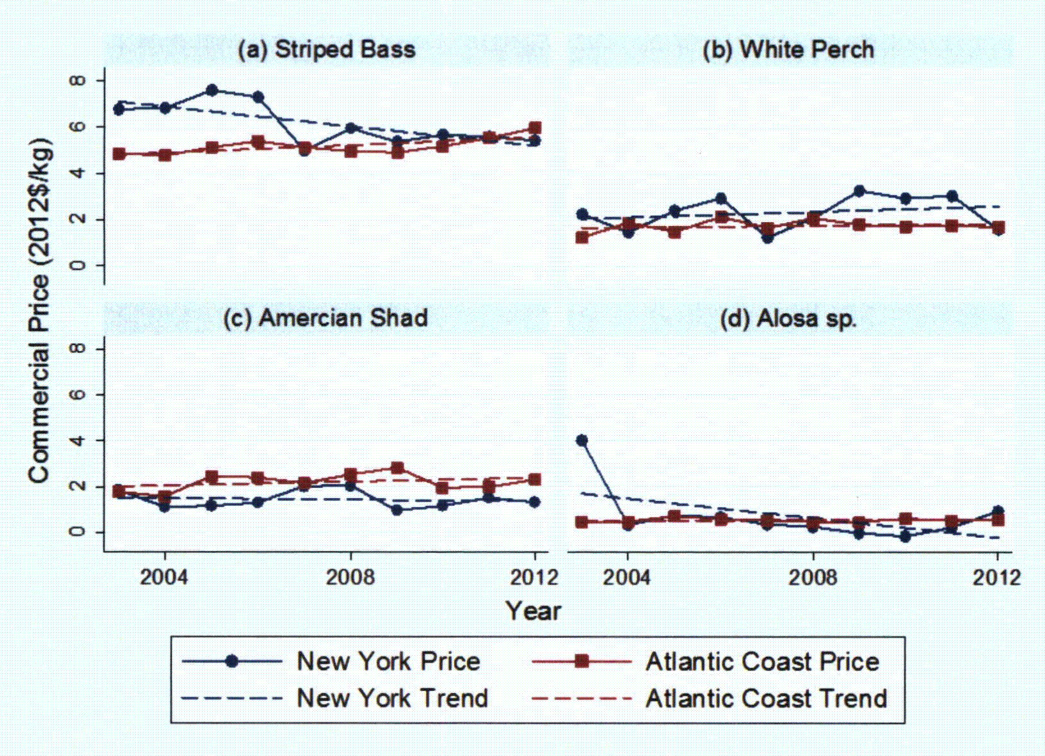
Table C-1 presents commercial prices per kg for the four species from 2003 to 2012 in New York and the Atlantic coast (converted to 2012 dollars using the GDP implicit price deflator). These commercial prices are based on the landings weights in Appendix B and nominal total values from NMFS (2013).

Table C-1. Commercial Prices in Constant Dollars (2012$/kg)

	Striped Bass		White Perch		American Shad		Alosa sp.	
	New York	Atlantic	New York	Atlantic	New York	Atlantic	New York	Atlantic
2003	$6.78	$4.86	$2.22	$1.24	$1.87	$1.79	$4.05	$0.50
2004	$6.83	$4.76	$1.47	$1.88	$1.11	$1.60	$0.33	$0.48
2005	$7.60	$5.13	$2.40	$1.50	$1.16	$2.47	$0.76	$0.72
2006	$7.30	$5.41	$2.92	$2.11	$1.32	$2.41	$0.69	$0.59
2007	$5.00	$5.12	$1.23	$1.66	$2.03	$2.16	$0.37	$0.53
2008	$5.95	$4.95	$2.07	$2.08	$2.07	$2.55	$0.27	$0.49
2009	$5.38	$4.91	$3.26	$1.79	$0.99	$2.86	-	$0.49
2010	$5.68	$5.18	$2.92	$1.71	$1.17	$1.98	-	$0.61
2011	$5.61	$5.55	$3.04	$1.76	$1.54	$2.01	$0.24	$0.55
2012	$5.45	$5.99	$1.58	$1.67	$1.33	$2.33	$0.95	$0.58
Average	$6.16	$5.19	$2.31	$1.74	$1.46	$2.22	$0.96	$0.55

Note: Nominal prices were converted to constant 2012 dollars using the GDP deflator.
Source: NMFS (2013) and NERA calculations as explained in text

Figure C-2 illustrates the trends in commercial prices. Note that commercial prices for striped bass have been relatively flat in both New York and the Atlantic coast, but commercial prices for white perch, American shad, and *Alosa* have fluctuated sharply in New York and have generally been steadier on the Atlantic coast.



Source: NERA calculations as explained in text

Figure C-2. Commercial Price Trends

b. Commercial Fish Prices Weighted by Landings

We use the prices from Table C-1 and data on annual commercial landings to estimate weighted average commercial prices for each species.

We based our weighted-average commercial prices for striped bass on price and landings data for New York, whereas the commercial prices for white perch, American shad, and *Alosa* were based on price and landings data for the Atlantic coast. The sharp fluctuations in the weight and price data in New York for white perch, American shad, and *Alosa* (as shown in Figure C-2) made this dataset less suitable than the Atlantic coast dataset for the development of long-term commercial price projections. Moreover, note that commercial prices for striped bass are higher in New York than in the Atlantic coast, and striped bass prices in New York have a downward trend (while prices in the Atlantic coast are relatively flat). This suggests that future commercial prices for striped bass may not be as high in real terms as the historical New York averages we use. Commercial prices for white perch, American shad, and *Alosa* are similar in New York and the Atlantic coast and are generally flat (except for a price spike for *Alosa* in 2003).

Table C-2 summarizes the resulting weighted commercial prices, which are used to estimate commercial fishing benefits.

Table C-2. Commercial Prices Weighted by Annual Landings (2012$/kg)

Striped Bass	White Perch	American Shad	Alosa sp.
$6.15	$1.70	$2.05	$0.54

Source: NERA calculations as explained in text

c. Changes in Commercial Fishing Prices

As noted above, increases in commercial fish populations due to reduced I&E could, in theory, lead to decreases in commercial fish prices. We follow EPA (2011) in assuming the price changes are equal to zero based upon the relatively small changes in harvest relative to the relevant market. For striped bass, EPA reports that elimination of all I&E losses would change commercial fish prices from $2.02 per pound to $1.98 per pound, or less than 2 percent. The effect of changes in I&E due to the introduction of CWWS or Cooling Towers at IPEC would of course be much smaller.

3. Changes in Producer Surplus

We follow EPA (2011) methodology in calculating the changes in producer surplus as fixed proportions of the changes in gross revenue from the increases in commercial harvests.

We estimate the changes in gross revenue using the data described above on the increases in commercial harvest and the commercial fish prices. That is, we multiply the expected changes in commercial catch by the ex-vessel prices established from data collected prior to any expected increase in catch.[29]

Increases in catch will lead to increases in gross revenues, but also to increases in costs, because there are some costs that vary with actual catch (e.g., boats might make more trips to the extent their storage capacity was filled in less time per trip, or boats might need more ice to preserve larger catches). We use the "Net Benefits Ratios" for the Mid-Atlantic region from the Proposed 316(b) Replacement Rule to estimate the fixed proportions of gross revenue that are increases in producer surplus (EPA 2011b, p. 6-7). These ratios are displayed in Table C-3.

Table C-3. Net Benefits as a Ratio of Gross Revenue

Striped Bass	White Perch	American Shad	Alosa sp.
67%	82%	84%	85%

Source: EPA (2011), p. 6-5

To estimate the change in net revenue, we apply the ratios in Table C-3 to the changes in gross revenue. The changes in gross and net revenue are displayed in Table C-4. As noted in EPA (2011) and as discussed above, our estimates of commercial fishing benefits due to CWWS and Cooling Towers at IPEC are equal to the increases in producer surplus.

29 We assume that the markets for fish distribution and retail sales are competitive, with the prices charged by those intermediaries equal to the marginal costs of the services provided.

Table C-4. Annual Gross and Net Revenues (2012$)

	Striped Bass	White Perch	American Shad	Alosa sp
Gross Revenues				
CWWS	$54,488	$86	$31	$67
Cooling Towers	$4,783	$8	$3	$5
Net Revenues				
CWWS	$36,507	$71	$26	$57
Cooling Towers	$3,205	$7	$3	$4

Source: NERA calculations as explained in text

C. Potential Implications of Unregulated Fisheries

A fishery does not function in a typical market. Fishermen do not own the ocean, so they are in direct competition with each other to catch a limited supply of a commonly-owned resource. Without government intervention, "open access" to a resource will lead to market failures. This section discusses how these market failures could potentially affect producer surplus in the commercial fishing industry.

1. Theory of the Tragedy of the Commons

Each fisherman imposes a negative externality on all other fishermen by fishing for the same stock. The more one fisherman catches, the fewer fish are available for others to catch (or the greater the effort they will have to exert to maintain a given level of catch). No individual fisherman has an incentive to consider his impact on other fishermen. In an unregulated (or under-regulated) fishery, the result is excessive fishing, which leads to sub-optimal stock levels and can lead, under some circumstances, to a collapse of the fish population. The level of fishing effort will be excessive because fishermen will continue to enter (or fail to exit) the industry so long as there is any gain to them individually, even if their private gain is more than offset by the negative externalities they impose on other fishermen.

This general phenomenon has been dubbed the "tragedy of the commons" (Hardin 1968), referring to the "open-access" problem associated with grazing on community-held land. In Hardin's example, no individual livestock owner ultimately gains any net benefit from use of the common property because each has the incentive to graze additional stock so long as there is any private gain. The result is that each livestock owner grazes more livestock than the optimum, and the community land is degraded by over-grazing, dissipating the benefits of all stock owners. Open-access fisheries are another classic example of this potential for over-use, and the resultant degradation (and perhaps, ultimately, destruction) of a common resource. Empirical studies of open-access fisheries have confirmed the theoretical insight that open-access use of a common resource erodes economic profits (Anderson 1986 and OECD 1997).

In an unregulated fishery, fishing will increase until all profits have been exhausted, in that the total gross sales revenue will exactly offset the total costs of fishing (Kolstad 2011). The producer surplus is thus equal to zero, as is the change in producer surplus due to any change in fish populations. The implication is that for an unregulated (or under-regulated) fishery, commercial fishing benefits due to reduced I&E would equal zero.

2. How Regulated Fisheries Attempt to Avoid the Tragedy of the Commons

To avoid excessive depletion of a fishery stock, regulators may set quotas, close the fishery at certain times, impose gear limitations, or take other steps to reduce the catch to sustainable levels. If such regulations limit entry efficiently (e.g., by auctioning quotas or by allocating quotas in a manner that is not influenced by future fishing effort or entry), they can in theory correct any market failures and avoid the "tragedy of the commons" entirely.

However, various common methods of regulating fisheries do not limit entry efficiently, and therefore fail to prevent the dissipation of value described above. For example, if an overall catch quota is established for a given time period (e.g., a year or quarter), and the relevant fishery is to be closed when that quota is reached, then the level of fishing effort devoted to catching that quota will be excessive. This is because no individual fisherman will take account of the fact that the more fish he catches, the sooner the fishery will be closed for the period; he receives all of the revenues from catching more fish before closure, but the cost of earlier closure is spread across all fishermen. If the price of fish rises as a result of higher demand or the cost of catching fish falls, additional fishermen will enter (and/or existing fishermen will intensify their levels of effort), and the closure will occur sooner. Boats and other equipment and, to some extent, fishermen, will be idle for a larger fraction of the year, raising overall costs per kg caught. Higher prices therefore will not benefit fishermen, except in the short run when entry is limited. Similarly, if the stock increases due to reduced mortality of eggs, larvae, or juvenile fish, entry (and/or increased effort) will similarly dissipate any theoretical gains to fishermen.[30]

3. Fishery Regulations in the Vicinity of IPEC

The impact of the "commons problem" necessarily depends on the characteristics of the regulations governing the fishery. As noted in Appendix B, striped bass, American shad, and *Alosa* are managed by the Atlantic States Marine Fisheries Commission ("ASMFC") and the New York State Department of Environment Conservation ("NYSDEC"). Restrictions on the species discussed in this study include:

- *Quotas.* Commercial fishing of striped bass in coastal waters is restricted through state quotas coordinated by the Atlantic States Marine Fisheries Commission (ASMFC 2003, 2010, 2013). NYSDEC produces serialized striped bass tags each year based on the New York quota and distributes these tags before the commercial fishing season to holders of striped bass commercial permits. Commercial fishermen must attach a tag to each striped bass they catch so that the commercial harvest can be tracked. Neither the tags nor the permits are transferable, and at present NYSDEC is not issuing new striped bass commercial permits (NYSDEC 2013a, b).

[30] To the extent that the price falls as a result of increased quantity, there will be some benefit to consumers.

- *Fishery closures*. NYSDEC allows striped bass to be caught commercially only between July 1 and December 15 or an earlier end date if the quota is projected to be met prior to December 15 (NYSDEC 2013a).
- *Minimum and maximum fish sizes*. NYSDEC allows striped bass to be caught commercially only for total lengths between 24 and 36 inches (NYSDEC 2013a).
- *Gear restrictions*. NYSDEC allows striped bass to be caught commercially using the following gear types only: hook and line, pound net, trap net, gill net, or as bycatch in otter trawls (NYSDEC 2013a).

These regulations, including limitations on entry into the striped bass commercial fishery, tend to mitigate the "tragedy of the commons" effects that have occurred in open-access fisheries. However, some portion of the potential value of increased fish stocks to commercial fisheries is still likely to be dissipated because commercial fishing permits are not distributed efficiently (through auctions or markets) and the commercial fishing season could close early if individual commercial fishermen intensify their effort.

4. Implications for Estimates of Commercial Fishing Benefits

If the fishery regulations in the vicinity of IPEC were perfectly efficient, the "tragedy of the commons" would not affect the estimates of commercial fishing benefits. As explained above, however, the actual regulations in place likely only mitigate the market failure instead of correcting for it entirely. These considerations suggest that, all else equal, the commercial fishing benefits would be lower than the calculations using the methodology described above, perhaps equal to zero.

D. Commercial Fish Price Uncertainty

There is some uncertainty about what commercial fish prices will be in future years. As part of our uncertainty analysis, we use 2003-2012 NMFS (2013a) historical data on commercial fisheries to develop alternative assumptions about commercial fish prices.

To test the sensitivity of our conclusions to alternative commercial fish prices, we created "low" and "high" commercial price cases using the minimum and maximum annual average commercial fish price for each species in the last ten years. Table C-5 shows these minimum and maximum values.

Table C-5. Base, Low, and High Commercial Prices by Fish Species

	Striped Bass	White Perch	American Shad	Alosa sp.
Base	$6.15	$1.70	$2.05	$0.54
"Low" (Minimum)	$5.00	$1.24	$1.60	$0.48
"High" (Maximum)	$7.60	$2.11	$2.86	$0.72

Source: NMFS (2013a); NERA calculations as explained in text.

Monte Carlo analysis requires that we also assume a distribution of commercial fish prices. Our base case prices are the average annual price from 2003-2012. For our Monte Carlo analysis, we assume that commercial prices for each species are distributed lognormally; lognormal distributions are commonly used to develop stochastic pricing models. We use the base case landings-weighted commercial price as the mean of each distribution and the landings-weighted sample standard deviation of annual commercial prices as the standard deviation of each distribution. These parameters are shown in Table C-6.

Table C-6. Lognormal Distribution Parameters for Commercial Prices by Fish Species

	Striped Bass	White Perch	American Shad	Alosa sp.
Mean	$6.15	$1.70	$2.05	$0.54
Standard Deviation	$0.85	$0.24	$0.35	$0.06

Source: NMFS (2013a); NERA calculations as explained in text.

E. Commercial Net Benefits Ratio Uncertainty

There is some uncertainty about the percentage of incremental revenue that will accrue to producers as surplus. To test the sensitivity of our results to alternative commercial net benefits ratios, we define two sensitivity cases: A "high" case in which we assume 100 percent of incremental commercial fishing revenues are surplus (and thus represent real benefits) and a "low" case that is symmetric to the "high" case. Table C-7 shows these sensitivity values for each modeled fish species.

Table C-7. Base, Low, and High Commercial Net Benefits Ratios by Fish Species

	Striped Bass	White Perch	American Shad	Alosa sp.
Base	67%	82%	84%	85%
"High" = 100%	100%	100%	100%	100%
"Low" = Base - (100% - Base)	34%	64%	68%	70%

Source: EPA (2011); NERA calculations as explained in text.

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Appendix D: Recreational Fishing Benefits

This appendix describes the methodology and data used to estimate the value that recreational anglers place on additional harvested fish due to reduced I&E due to CWWS and Cooling Towers at IPEC. We begin with an overview of the methodological issues related to valuing recreational catch and the methodology that EPA has used to develop estimates in the proposed 316(b) Replacement Rule (2011, Chapter 7), which include results for recreational anglers in the Mid-Atlantic (among other regions). The following section provides details on the specific information and methodology we used to develop our empirical estimates. The final section provides a comparison between the results of our study and the results we would obtain if we used the EPA's results for the Mid-Atlantic region.

A. Methodology for Estimating Recreational Fishing Benefits

1. Overview of Methodological Issues in Estimating Recreational Fishing Benefits

As discussed in Chapter IV, the total economic gain (consumers' surplus) from reduced I&E for recreationally harvested fish species is equal to the marginal value of recreational fish harvested multiplied by the increase in the number of recreationally harvested fish. The marginal value is equal to the value (i.e., willingness-to-pay) that recreational anglers would place on an additional harvested fish. As discussed below, we account for catch-and-release in calculating the value of changes in recreational harvest.

Recreational fishing and fish caught by recreational anglers are classic non-market commodities. Typically, recreational fishing services are not packaged and sold by private producers to private customers (although guide services and the like do exist), so market prices do not exist to indicate the value that recreational anglers place on fishing trips or fish caught. Nevertheless, economists have developed and implemented methods for valuing recreational fishing benefits.

The following is a brief summary of the issues involved in estimating the marginal value of recreational fish at a specific site such as IPEC:

1. *Travel Costs as Indicators of Willingness to Pay.* Travel costs to fishing sites include costs associated with vehicle use (e.g., gasoline and wear and tear on a personal vehicle) and the opportunity cost of time spent traveling. For a particular fishing site, different anglers face different travel costs. Similarly, an individual angler faces different travel costs for sites with differing characteristics (e.g., expected catch rates). Travel costs do not capture anglers' complete willingness to pay for recreational fishing trips to a site, but analysis of travel costs does allow for the estimation of anglers' responses to changes in variables that influence anglers' willingness to pay. The actual decisions made by anglers in response to differences among available sites—the anglers' "revealed preferences"[31]—

[31] There are two methods that can be used for estimating anglers' willingness to pay for recreational fishing opportunities. The first is the "stated preference" method, where hypothetical questions are posed to consumers in a survey (Freeman 2003). The second and more traditional method is the "revealed preferences" method,

provide an economically sound basis for estimating the value of recreational fishing opportunities and of fishing site attributes such as the expected fishing success or catch rate at a site (Freeman 2003).

2. *Models of Recreational Fishing Demand.* Economists have developed two basic empirical approaches that use travel costs to estimate the values that recreational anglers place on the marginal pound of fish caught: (1) the travel cost model of recreation demand ("TCM") and (2) the random utility model ("RUM") (Freeman 2003). The development of valid recreational fishing demand models using either TCM or RUM requires careful implementation (Freeman 2003 and Lesser, Dodds and Zerbe 1997). Data on recreational fishing trips are generally from surveys of actual fishing trips; a sound empirical analysis should ensure that the design and administration of the surveys avoid various types of bias (e.g., sampling bias, non-response bias). Additionally, since travel costs include the opportunity cost of time spent traveling, the analysis should include reasonable assumptions about the value of anglers' time. If these and other considerations (e.g., model specification) are handled appropriately, an analysis using either a TCM or RUM can produce useful valuation estimates that incorporate data on the actual behavior of anglers.

3. *Benefits Transfer using Pre-existing Studies.* Most benefit-cost analyses of regulations or permitting decisions do not attempt to develop original empirical studies. Instead, they rely on "benefits transfer" methods, which involve synthesizing results from pre-existing studies of recreational fishing benefits at similar sites into a valuation estimate for the specific site(s) under consideration. Benefits transfer methods can use the results from one or, ideally, numerous pre-existing valuation studies.

4. *Estimate a Marginal Benefits Curve using Meta-analysis.* A meta-analysis combines the results from various empirical studies by using statistical methods to fit a base model that provides a theoretical relationship between common study variables. In addition to utilizing sound statistical analysis, studies are suitable for inclusion in the meta-analysis if they are comparable to the site under consideration in regard to geographic location and fish species. Although studies may have different results for the value placed on additional catch, these differences may arise from widely different circumstances. For example, two studies of recreational fishing benefits may provide different results for the marginal value of an additional fish caught, but the results may reflect differences in the initial catch rate, i.e., the "baseline" catch rate to which the marginal fish caught is additional. The study with the lower marginal value might be based on an area where recreational anglers already catch many fish, while the study with the higher marginal value might be based upon an area where recreational anglers typically catch relatively few fish. In this case, the studies' results would not be inconsistent; they could simply

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which involves observing how consumers' preferences for a product are revealed by their market behavior in response to changes in the price or quality of a product. Although some recreational fishing studies have used stated preference valuation techniques, many economists are concerned that estimates of willingness to pay based on these techniques may not reflect actual values, as survey respondents may not actually behave in accordance with estimates of their WTP based on stated preference techniques (Portney 1994). Accordingly, where data of actual behavior is available, revealed preference techniques are preferred.

represent different points on a single curve that relates the marginal value of an additional fish caught to the initial catch rate. The result of the meta-analysis is an estimated marginal benefit curve, representing the value of additional catch to recreational anglers for varying site characteristics.

5. *Develop an Estimate of Marginal Fish Value to Recreational Anglers.* The results of the meta-analysis can be applied to the characteristics of the site under consideration to develop an estimate for the value of additional catch to recreational anglers at that site. For example, if the result of the meta-analysis includes the relationship between the expected catch rates and marginal fish values, the expected catch rate at the site under consideration can be used to estimate the marginal recreational fish value at that site.

2. Recreational Fishing Benefits

EPA (2011) provides an example of using the methodology outlined above based upon a national meta-analysis in its assessment of recreational fishing benefits for the proposed 316(b) Replacement Rule. Marginal values per fish for the species affected by I&E mortality were estimated using benefits transfer from a meta-analysis of 48 studies published between 1982 and 2004, with a sample of 391 observations of marginal values per fish (EPA 2011). The studies cover geographic regions throughout the United States and a wide variety of species caught in these regions.

The EPA meta-analysis (Johnston et al. 2006) included studies that used several different methods (including revealed and stated preference techniques), many different species, and different parts of the country. The benefit transfer function for the meta-analysis of recreational fishing studies was assumed to have the following form:

$$\ln(WTP) = intercept + \sum(coefficient_i)(Independent\ Variable\ Values_i)$$

The dependent variable is the natural log of the willingness-to-pay for catching an additional fish, and the independent variables characterize the species being valued, study location, baseline catch rate, elicitation and survey methods, demographics of survey respondents, and other specific characteristics of each study (EPA 2011, p. 7-2). The values for the various methodological attributes are set at the mean values from the metadata unless theoretical considerations dictate alternative specifications (EPA 2011, p. 7-3).

EPA uses regression analysis to estimate the coefficients of the functional equation described above. The regression equation is then used to predict the marginal values per fish. EPA excludes the error term in predicting marginal fish values, which results in benefits estimates that are more conservative and more consistent with the underlying studies (EPA 2011, p. 7-3).

Finally, to calculate the recreational welfare gain for each 316(b) regulatory alternative, EPA multiplied the marginal value per fish by the change in the number of fish that are lost due to I&E mortality that would otherwise be caught by recreational anglers (EPA 2011, p.7-6).

B. Estimating Recreational Fishing Benefits at IPEC

Following EPA (2011) and the general methodology outlined above, recreational fishing benefits at IPEC are calculated by multiplying the estimated changes in recreational fish harvests by an estimate of the marginal value per fish. The remainder of this appendix summarizes our methodology, focusing on the methodology we use to estimate that marginal value per fish.

1. Changes in Recreational Fish Harvests

We calculate gains in recreational harvest based on estimates of the total theoretical additional harvest and the percentage of that additional harvest that is caught by recreational fishermen. The estimates of annual theoretical additional harvest due to CWWS and Cooling Towers at IPEC are from ASAAC (2013) and are described in detail in Chapter IV. The estimates of the proportions attributed to recreational fishing are based on commercial and recreational landings data from NOAA, and is described in detail in Appendix B.

2. Marginal Value of Recreational Fish at IPEC

We follow the general methodology outlined in the previous section to estimate the marginal value of recreational fish at IPEC. Rather than use the EPA meta-analysis, however, we develop our own meta-analysis that is focused on the specific application to IPEC. Although the Johnston et al. (2006) includes a large number of studies and observations, the vast majority of these studies and observations relate to different species and different locations than the species and locations relevant for I&E reductions at IPEC. Moreover, EPA's use of a single estimate of the coefficient on catch rate for the wide range of species and locations makes applying the estimate to specific sites and species problematic. Thus, we use a more focused benefits transfer method—that involves a meta-analysis of relevant studies of recreational fishing benefits to determine the relationship between the catch rate and the value per fish—to develop our estimate of the social benefits of additional recreational catch due to CWWS or Cooling Towers.

a. Benefits Transfer Method

An original study of the species and areas relevant to the recreational fishing benefits evaluated in Chapter IV would require the development of an extensive dataset and accompanying data analysis. Many studies using TCM and RUM methods (in which willingness-to-pay is based on travel costs, as described above) have valued the benefits of improved recreational catch rates for a variety of fish species, fishing modes, and fishing locations relevant to IPEC. A benefits transfer approach—in which studies are chosen based on their quality and relevance to recreational fishing benefits at IPEC—is thus likely to provide reasonable estimates of marginal fish values.

b. Overview of the Meta-analysis

We developed a meta-analysis to estimate the relationship between the marginal value that recreational anglers place on fish caught or harvested and the average per-trip catch rate. This constitutes a marginal benefit curve for recreationally caught fish. The meta-analysis draws on studies that are particularly relevant to reductions in I&E at IPEC. The recreational benefits of the fish-protection alternatives are expressed in terms of the estimated number of additional fish that recreational anglers would harvest (i.e., catch and keep). Thus, the meta-analysis assesses values placed on the number of recreationally caught or harvested fish for locations and species relevant to the evaluated benefits. The study results included in the meta-analysis either provide, or allow the calculation of, estimates of the marginal value of a caught or harvested fish for the particular conditions evaluated in that study, specifically, the particular initial catch rate to which the estimated marginal value applies.

Catch rates for harvested fish are related to overall catch rates, which include harvested fish plus fish that are caught and released. Although the biological estimates of recreational fishing benefits in Chapter IV report only increases in number of harvested fish, such increases would likely coincide with increases in fish that are caught and released. Recreational anglers generally value catching fish, even if they do not keep (harvest) them. Because harvest catch rates and overall catch rates are related, the meta-analysis can, as described below, effectively estimate marginal values for number of harvested fish that include the values for corresponding caught and released fish.

Our meta-analysis involves four steps:

1. Develop the base model to determine the appropriate shape for the marginal benefit curve;

2. Obtain/select the relevant recreational fishing benefits studies;

3. Identify usable valuation results and corresponding catch rates; and

4. Use valuation and catch rate inputs to estimate the marginal benefit curve.

The estimated marginal benefit curve shows how the marginal value of a fish depends on the catch rate (within the range of the catch rates included in the meta-analysis). Given an appropriate catch rate for the recreational fishing benefits evaluated in Chapter IV, the estimated marginal benefit curve can provide a value for the recreational benefits.

c. Basic Statistical Model

Figure D-1 illustrates a hypothetical relationship, based on standard economic theory, between the value that an angler assigns to a recreational fishing trip and the number of fish caught or harvested (or expected to be caught or harvested) on the trip. As the number of fish caught or harvested increases, the value of the trip increases. However, as the number of fish increase, the value of each additional fish decreases. Formally, the value of the marginal fish decreases as the number of fish increases. The marginal value is the derivative of the function that relates the value of the fishing trip to the number of fish caught or harvested. The slope of the value curve at a given point is the marginal value at that point, i.e., at that catch rate.

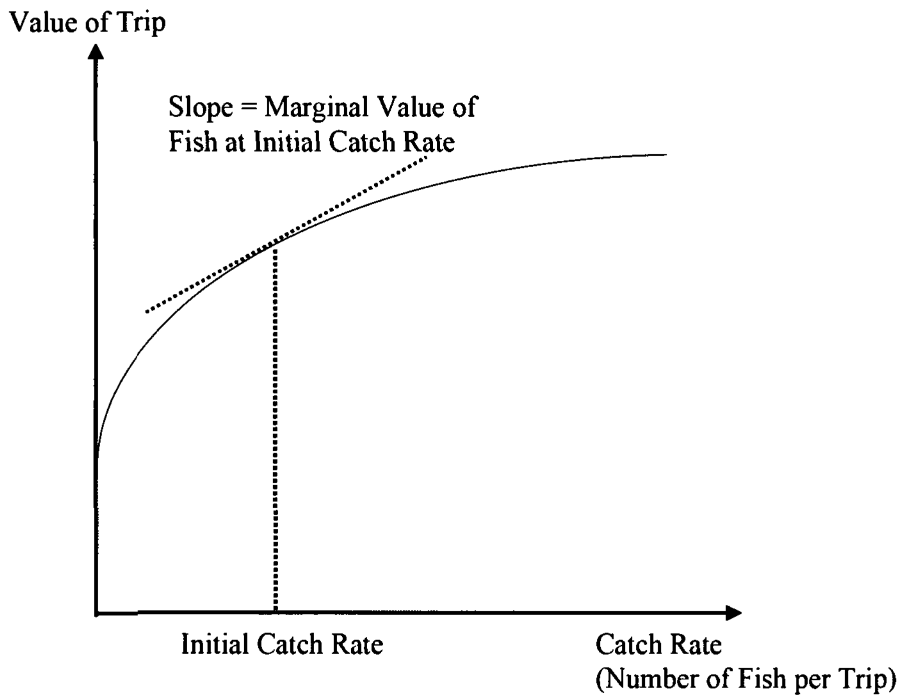

Figure D-1. Hypothetical Relationship between Value of Recreational Fishing Trip and Catch Rate

Suppose the marginal values from the hypothetical value curve in Figure D-1 have the relationship to the number of caught or harvested fish shown in Figure D-2. The curve is a hypothetical marginal benefit curve for the number of fish caught or harvested on a recreational trip. Given an initial catch rate, the curve shows the marginal value of an additional caught or harvested fish. As the catch rate increases, the marginal value of an additional fish decreases.

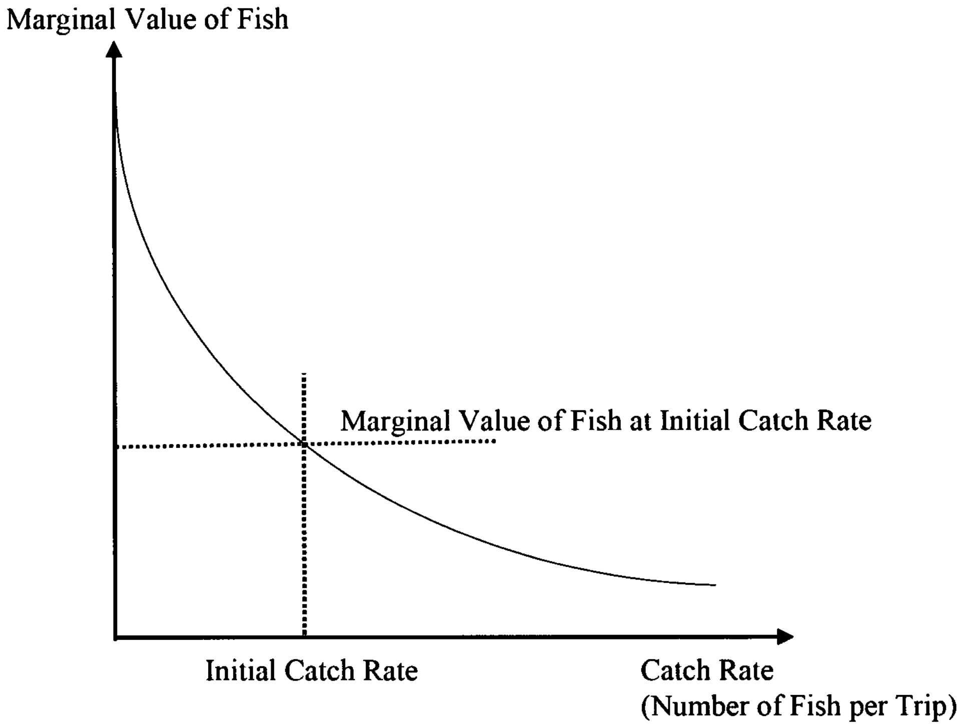

Figure D-2. Hypothetical Relationship between Marginal Value of Fish and Catch Rate

The meta-analysis assumes, as depicted in the hypothetical value curve, that the dollar value of a trip, V, depends on the square root of number of fish caught or harvested. Formally,

$$V = \alpha + \beta\sqrt{catch}\,, \tag{1}$$

where $catch$ is the number of fish caught or harvested during the trip, and α and β are parameters specific to the curve. The form of this curve is consistent with the economic theory of diminishing marginal returns and with specifications used in the valuation literature (see e.g., Hicks et al. 1999, Gautam and Steinback 1998, and EPA 2011). From Equation (1), the marginal value, MV, of additional caught or harvested fish is:

$$MV = \frac{\partial V}{\partial catch} = \frac{\beta}{2\sqrt{catch}} \tag{2}$$

The meta-analysis estimates the value of β based on the values of MV and $catch$ implied by results from the relevant literature. Specifically, the meta-analysis estimates marginal value using the equation:

$$MV = \frac{\partial V}{\partial catch} = \frac{\beta}{2\sqrt{catch}} + \varepsilon\,, \tag{3}$$

where ε is an error term. Given appropriate catch rates, such results translate readily into the dependent and independent variables ($\partial V / \partial catch$ and $1/\left(2\sqrt{catch}\right)$, respectively) in Equation 3.

Each study included in the meta-analysis provides a single data point which consists of a catch rate and a valuation result (in a form suitable for Equation 3).

d. Relevant Fishing Value Studies

From scores of potentially applicable studies of recreational fishing benefits that vary in scope by geographic location, type of water body (*e.g.*, bays, lakes, rivers, or oceans), type of fishing (shore fishing, private boat fishing, or charter boat fishing), targeted species, and estimation methodology, our meta-analysis includes studies selected according to four criteria (based on the guidance of EPA 2010, 2011):

1. *Location*. Studies that evaluate recreational fishing benefits for marine or tidal river locations on the Atlantic coast are presumed to be relevant.

2. *Fish species*. Because striped bass account for the vast majority of the estimated increases in recreational harvest from reduced I&E at IPEC (as shown in Chapter IV), we focused on studies that evaluate recreational fishing benefits for that species or more general evaluations for small game species (which include striped bass). We developed meta-analysis results for striped bass and small game collectively, but the different fish species potentially affected by implementation of fish-protection alternatives at IPEC have different values, and some species (e.g., *Alosa* sp.) probably have lower value to recreational anglers than we assign them based on the results for striped bass and small game from our meta-analysis. Our use of a marginal value for striped bass and small game for all species is thus a conservative assumption that tends to overstate the benefits of fish-protection alternatives at IPEC.

3. *Sound analysis*. Relevant studies should exhibit sound economic analysis. In particular, sampling protocols and estimation techniques in any included study should follow reasonable economic practice. The studies chosen are limited to those that employ either TCM or RUM approaches.

4. *Sufficient information*. The studies must report enough information about their results for the development of usable catch rates and valuation results for the meta-analysis. Note that in some cases the studies did not report complete details about the catch rates, but we were able to use data from the National Marine Fisheries Service (NMFS) and U.S. Fish and Wildlife Service (FWS) to develop the appropriate inputs.

These criteria allow the meta-analysis to include many studies (to improve the precision of the meta-analysis results) while excluding studies that lack quality or direct applicability to the current case (to avoid compromising the accuracy or relevance of the meta-analysis results). Table D-1 lists the studies included in the meta-analysis and identifies the locations and species evaluated in each study.

Table D-1. Studies Included in NERA Meta-Analysis

Authors	Publication	Location	Species
Gautam and Steinback	1998	VA to ME	Striped bass
Haab et al.	2000	FL to VA	Small game
Haab et al.	2009	FL to NC	Small game
Hicks et al.	1999	VA to ME	Small game
Norton et al.	1983	DE to NY	Striped bass
EPA	2004	DE to NJ	Striped bass
EPA	2004	DE to NJ	Small game

Developing the inputs for these studies involved the use of supplemental NMFS and FWS data related to catch rates. Specifically, NMFS data were used to estimate the total amount of recreational catch in each location and time period (including fish caught and released). FWS data were used to estimate the total number of trips for striped bass or small game in each location and period. The NMFS and FWS data were combined to estimate catch rates per trip for striped bass or small game.

e. Meta-Analysis Inputs

Table D-2 lists the data points included in the meta-analysis from each study. Some of the studies supply multiple inputs for the meta-analysis, because they develop values for multiple locations, species, or valuation methods, all of which fall within the bounds of the selection criteria. As noted above, the data points included in the meta-analysis reflect the combination of study results with supplemental NMFS and FWS data.

Table D-2. Inputs for NERA Meta-Analysis

			Originally Catch or	Initial Catch Rate (fish/trip)		Marginal Value (2012$/fish)	
Study	Method	Species	Harvest?	Catch	Harvest	Catch	Harvest
Gautam and Steinback (1998)	TCM	Striped bass	Catch	1.26	0.07	$6.12	$109.11
Gautam and Steinback (1998)	RUM	Striped bass	Catch	1.71	0.10	$4.59	$81.89
Haab et al. (2000)	RUM	Small game	Harvest	1.43	0.68	$4.22	$8.94
Haab et al. (2009)	RUM	Small game	Harvest	3.06	1.25	$1.30	$3.19
Hicks et al. (1999)	RUM	Small game	Catch	7.96	4.47	$3.90	$6.93
Norton et al. (1983)	TCM	Striped bass	Catch	0.48	0.33	$15.48	$22.27
EPA (2004)	RUM	Striped bass	Catch	2.48	0.23	$19.37	$207.36
EPA (2004)	RUM	Small game	Catch	2.32	1.21	$8.26	$15.81
Average						$7.91	$56.94

Note: Norton et al. (1983) estimate a discrete increase in value from an additional number of fish caught, and all other studies estimate marginal values.

Source: NERA calculations based on study values, NMFS (2013), and FWS (various years) as explained in text

As discussed above, to use study results that are reported in terms of overall caught fish (harvested fish plus caught and released fish), the meta-analysis assumes that, for a specific location and species (and other trip characteristics), the harvest catch rate and the overall catch rate are proportional. This assumption reflects the idea that, at a single site, marginal values estimated in terms of overall caught fish should agree (when scaled appropriately) with marginal values estimated in terms of harvested fish. Under this assumption, study results that are reported in terms of overall caught fish can be translated directly into equivalent results in terms of harvested fish (i.e., fish caught and kept).

For example, two economists may each perform a valuation study at the same site, but one may focus on harvested fish and the other on overall caught fish (including those caught and released). The two should agree as to the overall value of an average trip to that site. Suppose the estimated value of an additional fish caught (harvested plus catch-and-release) in one study is $10. If anglers could expect, on average to keep one fish for every three caught, then we would expect a study that estimated the marginal value of a fish *harvested* to be about 3 x $10 = $30. Note that the latter estimate of value per fish caught in fact captures the value of the two additional fish caught but not kept for every fish harvested. We could use either value in a benefits-transfer study so long as the value per fish was applied to the corresponding change in total catch or in harvest.

Under the assumption described above, the meta-analysis can include studies that report results in terms of overall caught fish (i.e., harvest plus catch-and-release) or in terms of harvest only. NMFS data allow the translation of study results reported in terms of overall caught fish into equivalent results in terms of harvested fish, and vice versa. Additionally, because one harvested fish is equivalent to more than one overall caught fish, the estimated marginal value of harvested fish includes the marginal value of the additional fish that are caught but released. Table D-2 shows whether each study originally evaluated overall catch or harvested fish. Catch rates per trip and marginal values per fish were developed for all studies in terms of both overall catch and harvest.

f. Results of NERA Meta-Analysis

Table D-3 presents the results of two OLS regressions based on the functional form displayed in Equation 3 and the marginal values in Table D-2 in terms of total catch and harvest. The estimated value of the coefficient β is $20.07 for the meta-analysis in terms of total catch and $66.76 for the meta-analysis in terms of harvest.

Table D-3. Regression Results of NERA Meta-Analysis

	Catch	Harvest
Estimated β	20.07	66.76
Standard error of β	4.88	19.43
Adjusted R^2 of regression	0.71	0.63
Standard error of equation	5.70	57.64

Source: NERA calculations as explained in text, based on the information in the studies included in the meta-analysis as well as NMFS (2013) and FWS (various years)

The estimated marginal value (2012$) in terms of total catch rate is thus:

$$MV = \frac{\partial V}{\partial catch} = \frac{\$20.07}{2\sqrt{catch\ (total)}} = \frac{\$10.04}{\sqrt{catch\ (total)}} \tag{4}$$

The estimated marginal value (2012$) in terms of harvest rate is thus:

$$MV = \frac{\partial V}{\partial catch} = \frac{\$66.76}{2\sqrt{catch\ (harvest)}} = \frac{\$33.38}{\sqrt{catch\ (harvest)}} \qquad (5)$$

We used data from NMFS (2013) and FWS (various years) to estimate the catch rate per trip for additional fish caught or harvested due to reduced I&E at IPEC. Table D-4 presents information on recreational striped bass fishing trips, total striped bass recreational catch (including catch-and-release), and striped bass recreational harvest in New York from 2007 to 2011.

Table D-4. Striped Bass Trips, Total Catch, and Harvest in New York (2007-2011)

Trips (millions)	10.7
Total catch (millions of fish)	8.3
Harvest (millions of fish)	2.7
Ratio of total catch to harvest	3.1
Catch rate per trip: Total catch	0.77
Catch rate per trip: Harvest	0.25

Source: NERA calculations based on NMFS (2013) and FWS (various years)

Based on these numbers, the catch rate in terms of total catch is 0.77 fish per trip, and the catch rate in terms of harvest is 0.25 fish per trip. Using these catch rates, the marginal value in terms of total catch (based on Equation 4) is $11.45 per fish caught, and the marginal value in terms of harvest (based on Equation 5) is $66.84 per fish harvested.[32]

As discussed in Chapter IV, ASAAC (2013) provided estimates of theoretical increases in fish harvests from reducing I&E at IPEC. The marginal value above in terms of total catch can be converted to a marginal value in terms of harvest using the ratio of total catch to harvest in Table D-4. This yields $35.28 per fish harvested, which is lower than the marginal value from the meta-analysis directly in terms of harvest ($66.84 per fish). We used the higher marginal value in terms of harvest ($66.84 per fish) to develop benefits estimates.

C. Comparison with Results Using EPA Meta-Analysis

As described above, EPA's proposed 316(b) Replacement Rule uses a meta-analysis of 48 studies published between 1982 and 2004, with a sample of 391 observations of marginal values per fish (EPA 2011). As discussed above, however, the majority of these studies and observations relate to different species and different locations than the species and locations relevant for I&E reductions at IPEC. Moreover, EPA's use of a single estimate of the coefficient on catch rate for the wide range of species and locations makes applying the estimate to specific sites and species somewhat problematic. Despite these limitations of the EPA meta-analysis, it is useful to compare the estimate above from our meta-analysis with the corresponding information from EPA's meta-analysis.

EPA (2011, p. 7-5) estimated that additional overall catch of small game in the Mid-Atlantic region has a marginal value of $5.88 per fish caught per trip day (2009$). Based on the GDP

[32] Note that the catch rates shown in the text are rounded. Catch rates used to calculate values per fish caught and per fish harvested were at a greater precision than values shown in the text.

price inflator, this is $6.19 per fish caught per trip day (2012$). EPA mentions in a footnote in an earlier version of this analysis that:

> Although some studies included both multiple and single day trips, the average angling trip length was often not provided. However, the majority of recreational angling trips are single-day trips. According to the 2001 National Survey of Hunting, Fishing, and Wildlife Associated Recreation (FWS, 2002), the average angling trip length was 1.27 days. (EPA 2006, p. A5-13, footnote 5)

Thus, converting EPA's marginal value of an additional fish per day into the marginal value of an additional fish per trip, using the suggested scaling factor of 1.27, yields an estimate of $7.86 per fish caught per trip (2012$). As shown above in Table D-4, NMFS and FWS data indicate that about 3.1 striped bass are caught overall in New York for each fish harvested. Thus, the EPA marginal value of $7.86 per fish caught can be converted for IPEC to $24.37 per fish harvested (2012$).

This EPA value can be compared to the marginal value we calculate. In terms of harvested fish, the marginal value we use for our benefits estimates ($66.84 per fish harvested) is substantially higher than the marginal value of $24.37 derived from EPA (2011).

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Appendix E: Assessment of Potential Non-use Benefits

This appendix summarizes our assessment of potential non-use benefits from cylindrical wedgewire screens (CWWS) and Cooling Towers at IPEC. The appendix provides background on the nature of non-use benefits, summarizes relevant biological information regarding the impacts of impingement and entrainment (I&E) at IPEC, and discusses guidance from various sources—including EPA and the economics literature—for assessing the potential significance of non-use benefits in situations in which no empirical study is available. We are not aware of any study that has assessed the potential non-use benefits of reducing I&E at IPEC or any study that could be used appropriately to provide the basis for assessing non-use benefits due to reduction in I&E at IPEC. The economics literature provides information on the only method that can be used to monetize non-use benefits—surveys of willingness-to-pay—noting their substantial cost and the difficulty of developing reliable estimates.

Economists also have considered the circumstances in which non-use benefits are likely to be significant and these analyses provide the bases for a qualitative assessment of non-use benefits of installing CWWS or Cooling Towers at IPEC. These assessments indicate that non-use benefits are not likely to be significant when the gains are to a subpopulation of a widely dispersed wildlife species—which the biological information indicates is the situation in this case—and thus we conclude that installing CWWS or Cooling Towers at IPEC is not likely to generate significant non-use benefits.

A. Background on Non-use Benefits

1. Nature of Potential Non-use Benefits

As noted in Chapter IV, EPA materials and the economic literature include discussions of benefits not associated with any direct use by people. Non-use benefits may arise if people value the change in an ecological resource without the prospect of using the resource or enjoying the option to use it in the future. The EPA *Guidelines*, for example, note that there are various possible types of non-use values.

1. Bequest value, where an individual places a value on the availability of a resource to future generations;

2. Existence value, where an individual values the mere knowledge of the existence of a good or resource; and

3. Paternalistic altruism, where an individual places a value on others' enjoyment of the resource (EPA 2010, p. xiv).

The *Guidelines* note that environmental policies may have non-use benefits from improvements to "relevant species populations, communities, or ecosystems" (EPA 2010, p. 7-9). In terms of improvements to relevant species populations, for instance, people may attach non-use benefits to preserving a threatened or endangered species (EPA 2010, p. 7-18).

2. Developing Monetary Values for Non-use Benefits

As the *Guidelines* and other commentators note, the potential monetary value of these non-use benefits cannot be measured using the traditional market-related techniques that economists have developed to measure use benefits. These traditional methods involve using market prices, either directly or indirectly, to provide information on the value that households place on environmental goods and services. The *Guidelines* note that non-use benefits can be estimated only through stated preference (SP) valuation methods. In SP methods, surveys are designed to elicit information on the value that people would attach to hypothetical scenarios (EPA 2010, p. 7-18). As the *Guidelines* note, however, a major disadvantage of SP methods is that they may be subject to systematic biases that are difficult to test for and correct (EPA 2010, p. 7-35). Moreover, as many analysts have pointed out, it is difficult, time-consuming, and expensive to undertake surveys to estimate non-use benefits.

There is a large literature on SP techniques and the means that might be used to avoid systematic biases and other potential problems. As the *Guidelines* note, a report prepared by a panel of experts convened by the National Oceanic and Atmospheric Administration (NOAA) is often cited as a primary source of guidelines for SP techniques. The panel consisted of five distinguished economists—including two Nobel laureates, Kenneth Arrow and Robert Solow—and considered the usefulness of SP for policy analysis. Their report (Arrow et al. 1993) provides an extensive set of guidelines for survey construction, administration, and analysis. In the Panel's view, "…the more closely the guidelines are followed, the more reliable the result will be" (p. 4609). The report also provides a list of key elements that it considers "burden of proof requirements" in order to develop a valid survey (p. 4609).

Given these guidelines and burden of proof requirements, the Arrow-Solow Panel concludes its report noting that:

> [U]nder those conditions (and others specified above), CV [contingent valuation[33]] studies convey useful information. We think it is fair to describe such information as reliable by the standards that seem to be implicit in similar contexts, like market analysis for new and innovative products and the assessment of other damages normally allowed in court proceedings. ...CV [contingent valuation] produces estimates reliable enough to be the starting point of a judicial process of damage assessment, including passive use values [i.e., nonuse values] (p. 4610).

The validity of SP techniques and studies has been the source of much subsequent discussion and commentary in the academic literature as well as in textbooks on benefit-cost analysis and environmental economics. Boardman et al. (2011) point out that although estimating the value of a "unique and long-lived" resource is important, the methods that currently exist lack sufficient reliability to be reasonably included in cost-benefit analysis in most cases (p. 228). Kolstad (2011) similarly explains that SP surveys are controversial because they do not reflect real

[33] Stated preferences studies are sometimes referred to as "contingent valuation" studies.

choices (p. 207). A recent symposium considered comments from supporters and detractors of the approach.[34]

Given the difficulties of developing a valid SP study, various commentators have suggested first assessing whether non-use values are likely to be significant before undertaking a study to estimate them.[35] Bateman et al. (2002), for example, note that "[o]ne of the issues to be determined before commissioning a study is the extent to which non-use values are likely to be important" (p. 74). The economic literature provides a basis for qualitative assessments by identifying the circumstances in which non-use values are likely to be significant.

3. Implications for Potential Non-use Benefits of CWWS or Cooling Towers at IPEC

The fact that non-use benefits are expensive and difficult to assess with accuracy suggests the usefulness of determining in the first instance whether non-use benefits are likely to be significant and thus whether monetization is justified. For this analysis, it is useful first to clarify the nature of theoretical biological benefits from CWWS and Cooling Towers at IPEC. This information can be used to judge likely significance of non-use benefits and also provide the basis for a qualitative assessment.

B. Overview of Relevant Biological Information on CWWS and Cooling Tower Benefits

To evaluate whether installation of CWWS or Cooling Towers at IPEC could lead to significant non-use benefits, it is useful to begin with assessments of the theoretical biological impacts of IPEC I&E. For biological assessments, we rely primarily upon information developed by the National Marine Fisheries Service and by Barnthouse et al. (2002), Van Winkle and Young (2008), Barnthouse et al. (2008), Barnthouse et al. (2010), and Barnthouse (2013). In this section, we summarize the relevant biological assessments, first for threatened and endangered species and then for other species.

1. Threatened and Endangered Species Affected by CWWS and Cooling Towers at IPEC

Entergy (2007), NRC (2010), and the CWWS SEQRA report provide information on the species that have been impinged and entrained at IPEC. Of these species, only two have special status as threatened or endangered species: (1) shortnose sturgeon; and (2) Atlantic sturgeon. The shortnose sturgeon has been listed as an endangered species by the federal government since 1967 (FWS 2013) and the New York State Department of Environmental Conservation (DEC) since 1973 (DEC 2013). The Atlantic sturgeon has been listed as an endangered species in the New York Bight by the federal government since 2012 (NOAA 2013) but does not have special

[34] The symposium is in the Fall 2012 issue of the *Journal of Economic Perspectives* (Volume 26, Number 4). See Kling et al. (2012), Carson (2012), and Hausman (2012).

[35] This presumes that an appropriate existing study is not available that could be used directly or as the basis for a valid benefit transfer application.

status from DEC. Both species forage in the part of the Hudson River where IPEC is located, but they spawn further north. Their migratory and spawning patterns make them susceptible to impingement at IPEC but not susceptible to entrainment.

a. National Marine Fisheries Service Biological Opinion on Potential Impacts of IPEC

The National Marine Fisheries Service (NMFS) prepared a recent report to the U.S. Nuclear Regulatory Commission (NRC) regarding IPEC's impacts under the current configuration on shortnose and Atlantic sturgeon. The following is a summary of the conclusions:

> After reviewing the best available information on the status of endangered and threatened species under NMFS jurisdiction, the environmental baseline for the action area, the effects of the proposed action, interdependent and interrelated actions and the cumulative effects, it is NMFS' biological opinion that the continued operation of Indian Point Unit 2 [and Unit 3] is likely to adversely affect but is not likely to jeopardize the continued existence of shortnose sturgeon or the New York Bight, Gulf of Maine or Chesapeake Bay DPS [distinct population segment] of Atlantic sturgeon (NMFS 2013, p. 126).

As noted in this excerpt, the NMFS conclusion is based on detailed review of species range and population trends as well as substantial historical data on I&E at IPEC. In terms of range and population trends for shortnose sturgeon, NMFS notes "anecdotal evidence that shortnose sturgeon are expanding their range in the Hudson River" and "evidence that the Hudson River population of shortnose sturgeon experienced tremendous growth between the 1970s and 1990s and that the population is now stable at high numbers" (p. 115). For Atlantic sturgeon, NMFS notes that "the available information on trends indicates that there may be a slight increasing trend in juvenile abundance in the Hudson River since the mid-1990s" (p. 122).

Regarding entrainment at IPEC, NMFS notes that "[b]ased on the life history of the shortnose sturgeon [and Atlantic sturgeon], the location of spawning grounds within the Hudson River, and the patterns of movement for eggs and larvae, it is extremely unlikely that any shortnose sturgeon [or Atlantic sturgeon] early life stages would be entrained at IP2 and/or IP3" (pp. 58-59).[36] Indeed, there is no evidence from historical I&E studies of entrainment of shortnose sturgeon or Atlantic sturgeon at IPEC (pp. 58-59). Thus, the focus of the NMFS analysis is on impingement impacts.

Based on historical impingement data for IPEC, NMFS assumes that 26 shortnose sturgeon would be impinged each year at IPEC, leading to a cumulative total of 562 impinged individuals over the NRC relicense period (through 2033 for Unit 2 and 2035 for Unit 3). NMFS further assumes that all impinged individuals would suffer mortality. While these deaths "will reduce the number of shortnose sturgeon in the population compared to the number that would have been present absent the proposed action [i.e., relicensing], it is not likely that this reduction in

[36] NMFS uses the same language in two separate sections for evaluating impacts on shortnose sturgeon and Atlantic sturgeon.

numbers will change the status of this population or its stable trend" because the loss represents less than 1 percent of the relevant population of adult shortnose sturgeon (p. 117). For Atlantic sturgeon, NMFS concludes that "the death of an average of 19 juvenile New York Bight DPS [distinct population segment] Atlantic sturgeon annually for 23 years will not appreciably reduce the likelihood of survival of the New York Bight DPS (i.e., it will not decrease the likelihood that the species will continue to persist into the future with sufficient resilience to allow for the potential recovery from endangerment)" (p. 124).

For these reasons, NMFS concludes that although the current configuration at IPEC leads to impingement mortality for some shortnose and Atlantic sturgeon each year, these losses are "not likely to jeopardize the continued existence" of these species subpopulations in the Hudson River (p. 126). Thus, reducing or even eliminating I&E at IPEC is not likely to significantly improve the status of the species subpopulations. NMFS notes, however, that its report does not directly relate to construction of CWWS or Cooling Towers at IPEC, which would require a separate analysis (p. 12). This issue is addressed below.

b. Other Biological Evaluations on Potential Impacts of IPEC on Threatened and Endangered Species

Barnthouse et al. (2008, p. 7) report that they do not evaluate impacts on shortnose sturgeon "because there is broad consensus that CWIS at IP2 and IP3 have no impact [on shortnose sturgeon]." In a brief (2-page) "case study" for IPEC prepared by EPA as part of its analysis of the Replacement Rule, however, EPA notes that in April 2010, DEC denied Entergy's request for a Clean Water Act Section 401 Water Quality Certificate for IPEC and EPA indicates that that the "NYSDEC denial letter cited, among other concerns, continuing concerns over I&E mortality including potential impacts to two sensitive species—the Shortnose Sturgeon (currently listed as endangered) and the Atlantic Sturgeon (under consideration for endangered species status" (EPA 2011a, p. 2-21).

Barnthouse (2013) evaluates the information in the 2011 EPA case study with regard to concerns related to the two species in the context of the NYSDEC Staff denial letter. Barnthouse (2013) notes that EPA (2011a) failed to mention that a 1979 NMFS Biological Opinion stated that I&E at IPEC did not jeopardize the recovery of shortnose sturgeon. As noted above, this conclusion was reaffirmed by NMFS in its 2013 biological opinion. Barnthouse (2013) also notes that EPA (2011a) failed to mention that the 2003 Final Environmental Impact Statement (FSEIS) for Indian Point, Roseton, and Bowline Point "did not identify impacts of I&E on either sturgeon species as being of concern." Thus, Barnthouse (2013) concludes that the statements in EPA (2011a) about shortnose and Atlantic sturgeon are misleading and conflict with the NMFS (2013) conclusion that the CWIS at IPEC does not adversely affect the sustainability of shortnose and Atlantic sturgeon.

c. Assessment of CWWS and Cooling Tower Construction and Operation

The CWWS SEQRA report (TRC 2013) includes assessments of whether construction and operation of CWWS at IPEC would have an adverse impact on shortnose or Atlantic sturgeon.

Any potential adverse impacts from construction and operation of CWWS or Cooling Towers would tend to offset any potential non-use benefits of CWWS or Cooling Towers from reducing impingement of these species.

In terms of construction, the assessments in the CWWS SEQRA report note that sturgeon could be affected by dredging. They conclude, however, that any adverse impacts from construction would likely be small.

> Given the small area of the river bottom to be dredged, the use of tall sheet piling to isolate some dredge areas, the relatively low numbers of sturgeon likely to be in the dredging area, and the general construction noise and activity eliciting avoidance behavior, it is unlikely that either sturgeon species would be injured by the dredging equipment. Potential adverse impacts from indirect effects related to dredging, such as increased localized suspended sediments or loss of benthic prey, would be small (TRC 2013, Section 4.5.1.4).

These small construction impacts would occur only during the construction period for CWWS.

In terms of operation, the assessments in the CWWS SEQRA report note that sturgeon could be affected by the air burst system (ABS). They conclude, however, that any adverse impacts from operation would likely be small.

> While there is a possibility that juvenile or adult sturgeon may occur in the vicinity of the CWWS during operation [of the air burst system], the effect would be to startle the sturgeon. However, given the small probability of the co-occurrence in time and space of sturgeon at the CWWS array, adverse impacts to juvenile and/or adult sturgeon would only be small from operation of the ABS were it to be installed (TRC 2013, Section 4.5.2.4).

Thus, while operation of CWWS at IPEC would reduce impingement of sturgeon, dredging during the construction period and use of the ABS during operation could have small adverse impacts on sturgeon. These would tend to offset any non-use benefits for CWWS at IPEC. The Response Report contains information related to the potential impacts of Cooling Tower construction and operation on sturgeon.

2. Other Species Affected by CWWS and Cooling Towers at IPEC

This section summarizes biological assessments for species that are not on a list of threatened or endangered species. We provide a summary of expert biological assessments of the health of the various species potentially affected at IPEC; these assessments conclude that reductions in I&E at IPEC would not lead to any measurable increase in fish populations. Note that this conclusion applies both to harvested species and forage species.

a. Biological Expert Assessments

This section summarizes information from four biological evaluations related to I&E at IPEC. The species addressed in these reports include both harvested species and unharvested forage species such as bay anchovy and spottail shiner. These expert reports conclude that eliminating I&E at IPEC would increase neither the abundance of harvested species available to fishermen nor the abundance of forage species that support the Hudson River food web.

- **Barnthouse et al. (2002)**

Barnthouse et al. (2002) evaluate whether I&E at Indian Point and two other power stations on the Hudson River—Roseton and Bowline Point—have reduced fish population levels. They conclude that I&E has not reduced population levels:

> The data presented in the DSEIS [Draft Supplemental Environmental Impact Study] indicate that changes that most fisheries biologists would view as "adverse" have not occurred. Further, changes that have occurred appear to be inconsistent with the impact hypotheses discussed above [whether I&E at the stations has reduced fish population levels] and, therefore, are not reasonably attributable to the stations (p. 3).

- **Van Winkle and Young (2008)**

Van Winkle and Young (2008) analyzed nineteen taxa/species of fish, including all fish modeled by ASAAC (striped bass, white perch, American shad, *Alosa* sp. [alewife and blueback herring], bay anchovy, and Atlantic tomcod). Van Winkle and Young note:

> If entrainment at IP2 and IP3 were having an adverse impact on the Hudson River fish community, then species with high susceptibility to entrainment would have decreased, or increased less in abundance, over the past 32 years than would species with low susceptibility (p. 1).

Van Winkle and Young (2008) conclude from their statistical analysis of entrainment susceptibility and abundance trends for the various species that I&E at IPEC is not responsible for changes in abundance:

> This result is opposite the expected significant negative correlation if Indian Point entrainment were adversely affecting the population trends of susceptible species. Therefore, the effect of Indian Point entrainment on abundance patterns, if there is one, is not large enough to be statistically detectable in the 32 years of monitoring data (p. 7).

- **Barnthouse et al. (2008)**

Barnthouse et al. (2008) conclude that "entrainment and impingement associated with cooling-water withdrawals by IP2 and IP3 have not had an adverse impact on Hudson River fish populations and communities" (p. 79). They note:

> Considered together, the evidence evaluated in this report shows that the operation of IP2 and IP3 has not caused effects on early life stages of fish that reasonably would be considered "adverse" by fisheries scientists and/or managers. The effects of mortality at IP2 and IP3 on the survival and abundance of susceptible populations cannot be detected, even after 30 years of intensive monitoring. Those changes that have occurred are more likely attributable to predation by the Hudson River's rapidly growing striped bass population (p. 79).

These conclusions are based upon two principal types of analyses.[37] First, Barnthouse et al. (2008) address the causes of decline in abundance of young-of-year white perch, Atlantic tomcod, bay anchovy, American shad, and river herring (*Alosa* sp.). They find that the declines of these populations are closely associated with overharvesting (in the case of American shad) and increased predation from a rebounding striped bass population in the Hudson River, rather than I&E at IPEC (p. 79).

Second, Barnthouse et al. (2008) find that, in the case of striped bass and American shad, entrainment and impingement mortality at IPEC is negligible compared to fishing mortality and does not affect the ability of the fish populations to sustain themselves (p. 11). Entrainment losses consist of mainly eggs and larvae which have low probability of surviving to adulthood. These losses are unlikely to affect an aquatic community in a manner that would demonstrate "Adverse Environmental Impact" (p. 12).

- **Barnthouse et al. (2010)**

An additional analysis documented in Barnthouse et al. (2010) found that "even if entrainment of fish larvae at Units 2 and 3 were completely eliminated, no measurable changes in the abundance of older, juvenile fish are likely to occur" (p. 47).

Barnthouse et al. (2010) notes that the species modeled by ASAAC account for the vast majority of losses at Hudson River power stations:

> In addition to being considered important due to their recreational, commercial, and ecological value, these species have historically accounted for more than 98% of fish larvae and 92% and of juvenile (YOY) fish captured, respectively, in the utilities' LRS [Long River Survey] and Beach Survey (p. 9).

They summarize the results of their analysis as follows:

[37] Barnthouse et al. (2008) also summarize the results of previous analyses, including Van Winkle and Young (2008).

> These figures also show the range of increases that would be expected to occur if current levels of entrainment losses at IPEC were eliminated. For all taxa, the range of projected increases in numbers of age-1 equivalents due to eliminating entrainment is very small compared to the range of year-to-year increases calculated from historical data. Within this small range, decreases in corresponding abundance of juveniles have occurred as frequently as increases. The estimated probability of observing an increase in juvenile abundance, when the increase in PYSL abundance is within the range that would be projected due to elimination of entrainment, is not significantly different than 50:50 for any of the four taxa evaluated (p. 40).

Appendix C of Barnthouse et al. (2010), by AKRF, provides the following additional information regarding the analytical methodology and results:

> Field measurements of changes in juvenile abundance in response to increases in larval abundance have been recorded by the Long River Survey ("LRS"), Beach Seine Survey ("BSS"), and Fall Juvenile Survey ("FJS") for over 30 years on the Hudson River (field data documented in annual "Year Class Reports", e.g. EA, 1996). The historical data document what can be viewed as naturally-occurring experiments (i.e., the response of abundance at the juvenile lifestage to a change in abundance at the larval lifestage) of the effects of increases in riverwide post-yolk sac larva ("PYSL") abundance (that can be expressed in terms of age-1 equivalents) on changes in riverwide juvenile abundance. Those naturally-occurring experiments can be used to address the question of what demonstrable changes in fish populations can be expected from reducing entrainment losses at the IPEC Stations (Appendix C, p. 2)
>
> For each of the 4 taxa (American shad, river herring, striped bass and white perch), the projected range of potential annual increases in age-1 equivalents due to eliminating current entrainment losses associated with the Stations' operation is very small compared to the range of year-to-year increases in riverwide PYSL abundance calculated from historical data (Figures 13 through 16). Within the projected range of potential annual increases in age-1 equivalents due to eliminating current entrainment losses associated with the Stations' operation, the estimated probability of observing an increase in juvenile abundance is not significantly different than 50:50 for any of the 4 taxa (Table 2). Within that range, the estimated average annual change in juvenile abundance is not significantly different from zero for any of the 4 taxa (Appendix C, p. 8)
>
> Based on: (1) empirical relationships between year-to-year increases in riverwide PYSL abundance (expressed in terms of age-1 equivalents) and year-to-year changes in riverwide juvenile abundance, and (2) the projected ranges of relatively small potential increases in age-1 equivalents due to eliminating current entrainment losses associated with IPEC Stations' operation, no alternative intake technology considered as part of Entergy's alternative technology assessment

would be expected to result in a demonstrable increase in juvenile abundance of American shad, river herring, striped bass or white perch (Appendix C, p. 8).

b. Other Biological Evaluations

As noted above, EPA in its Replacement Rule includes a brief case study related to IPEC (EPA 2011a, pp. 2-20 to 2-21). The case study provides the following paragraph regarding the potential effects of IPEC on fish species.

> Results suggest that I&E mortality impacts to the local and transient anadromous fish species are substantial. For example, studies of fish entrainment in 1980 predicted fish class reductions ranging from 6 to 79 percent, depending on fish species (Boreman and Goodyear 1988). Subsequent sampling work predicted year-class reductions due to I&E mortality of 20 percent for striped bass, 25 percent for bay anchovy, and 43 percent for Atlantic tomcod. The Final Environmental Impact Statement (FEIS) prepared by the New York State Department of Environmental Conservation (NYSDEC) concluded these levels of mortality 'could seriously deplete any resilience or compensatory capacity of the species needed to survive unfavorable environmental conditions (USEPA 2004a) (EPA 2011a, pp. 2-2- to 2-21).

Barnthouse (2013) evaluates the information provided in this case study. He notes that impact estimates from Boreman and Goodyear (1988) represent the cumulative impacts from six Hudson River power plants, not IPEC alone. Moreover, he notes that the range of estimates that EPA used from Boreman and Goodyear (1988) is misleading and that EPA does not identify the studies it cites as "subsequent sampling work." Indeed, the 1999 Draft Environmental Impact Statement (DSEIS) for Indian Point, Roseton, and Bowline Point indicated significantly smaller impacts on striped bass, bay anchovy, and Atlantic tomcod than the values given by EPA. Moreover, Barnthouse (2013) states that the FEIS conclusions regarding population and community impacts are unsupported and incorrect. Barnthouse (2013) concludes that the information cited in EPA (2011a) regarding population and community impacts "contains significant errors and omissions and does not accurately reflect current understanding." He concludes that the information in EPA (2011a) does not change his conclusion that I&E at IPEC does not have a measurable effect on the various fish populations mentioned.

3. Implications for Potential Non-use Benefits of CWWS and Cooling Towers at IPEC

The biological assessments summarized above indicate that I&E at IPEC does not have a significant impact on the sustainability of fish populations, including threatened and endangered species as well as other species. As discussed below, sustainability of populations is a major factor influencing whether non-use benefits are likely to be important from the standpoint of an economic evaluation. Thus, reducing I&E at IPEC with CWWS or Cooling Towers is not likely to have important non-use benefits associated with adverse effects on the viability of various fish species. Below we use this information in conjunction with the relevant economic guidance to assess the likely significance of non-use benefits from CWWS and Cooling Towers at IPEC.

C. EPA Guidance for Site-Specific Evaluation of Non-use Benefits in 316(b) Rules and Proposed Replacement Rule

This section describes the treatment of potential non-use benefits in recent EPA rules for cooling water intake under Section 316(b) of the Clean Water Act. In particular, we consider the guidelines EPA has provided for the assessment of non-use benefits in individual permit cases in these various documents to provide background and context for our assessment of non-use benefits for CWWS and Cooling Towers at IPEC. These rules include (1) the Phase II Rule issued in 2004; (2) the Phase III Rule issued in 2006; and (3) the proposed Replacement Rule issued (as a proposal) in 2011. As discussed below, EPA also released information in 2012 on a SP survey that may be used to estimate the potential benefits of the Replacement Rule.

1. EPA 316(b) Phase II Rule (2004)

EPA's Phase II Rule, issued in 2004, sets cooling water intake standards for power generation facilities operating or under construction by January 2002. The rule applies to facilities that are designed to use at least 50 million gallons of cooling water per day.

a. Guidance for Site-Specific Assessments

The Phase II Rule recommends first reviewing biological information to determine whether to monetize potential non-use benefits. The rule recommends that analysts consider monetizing potential non-use benefits in cases where impingement and entrainment cause substantial harm to:

1. A threatened or endangered species;
2. The sustainability of populations of important species of fish, shellfish or wildlife; or
3. The maintenance of community structure and function in a facility's waterbody or watershed" (EPA 2004, p. 41648).

If none of these three criteria is met, "monetization is not necessary" (p. 41648).

b. Implications for Potential Non-use Benefits of CWWS and Cooling Towers at IPEC

As noted above in the section on biological impacts, NMFS (2013) implies that reducing I&E at IPEC (e.g., through installation of CWWS or Cooling Towers) would not lead to significant improvements in the status of threatened or endangered species (namely shortnose or Atlantic sturgeon). Moreover, Barnthouse et al. (2008 and 2010) conclude that reducing I&E at IPEC would not materially improve fish populations and would not affect the maintenance of community structure or function. Since none of EPA's three criteria in the Phase II Rule is met, potential non-use benefits from installation of CWWS or Cooling Towers at IPEC do not need to be monetized based on this guidance.

2. EPA 316(b) Phase III Rule (2006)

EPA's Phase III Rule, issued in 2006, establishes standards for the cooling water intake systems of new offshore and coastal oil and gas facilities that are designed to use more than 2 million gallons of water per day.

a. Guidance for Site-Specific Assessments

The Phase III Rule includes the following guidance regarding monetization of potential non-use benefits for site-specific assessments.

> Non-use benefits can generally only be monetized when two steps have been completed:

1. Environmental impacts are quantified; and
2. A monetary value is available to be assigned to those impacts (EPA 2006, p. 35017).

b. Implications for Potential Non-use Benefits of CWWS and Cooling Towers at IPEC

The second of EPA's two criteria for monetization in the Phase III Rule is that a monetary value be available for assignment to relevant environmental impacts. We are not aware of any study that has assessed the potential non-use benefits of reducing I&E at IPEC or any study that could be used appropriately to provide the basis for assessing non-use benefits due to reduction in I&E at IPEC. Thus, the second criterion outlined above is not met. As a result, this guidance implies that monetization is not necessary for this analysis.

3. EPA 316(b) Proposed Replacement Rule (2011)

EPA's proposed Replacement Rule would set standards on best technology available (BTA) for all existing power generating and manufacturing facilities that withdraw more than 2 million gallons per day. EPA evaluated four alternative regulatory approaches in the proposal and stated that it was inclined to base the final rule on Option 1, which would set impingement standards for facilities withdrawing more than 2 million gallons per day and would use site-specific determinations to select BTA for entrainment.

a. Guidance for Site-Specific Assessments

EPA's proposed Replacement Rule provides the following background on assessing non-use benefits:

> Non-use benefits...may be assessed on the basis of benefits transfer analysis (using findings from prior analyses involving a similar study context) or by performance of a peer-reviewed stated preference survey to assess the value

> assigned for the environmental improvements resulting from the technology installation (EPA 2011, p. 22261).

The proposed rule also provides the following guidance for monetizing non-use benefits:

> If appropriate data are available from stated preference studies or other sources that can be applied to the site being evaluated, these should be used to monetize non-use values. Otherwise, non-use values should be evaluated qualitatively (EPA 2011, p. 22261).

b. Implications for Potential Non-use Benefits of CWWS and Cooling Towers at IPEC

The guidance in EPA's proposed Replacement Rule indicates that non-use benefits are to be assessed using existing benefit transfer or peer-reviewed stated preference studies. That information is required for quantifying and monetizing potential non-use benefits. When such studies are not available, however, EPA states in the proposed Replacement Rule that it is appropriate to assess non-use values qualitatively. Since we are aware of no stated benefit study regarding non-use benefits at IPEC and no study that would appropriately provide the basis for benefit transfer to calculate non-use benefits from reduced I&E at IPEC, this guidance indicates it is appropriate to assess potential non-use benefits of CWWS and Cooling Towers at IPEC qualitatively.

4. EPA 316(b) Survey (2012)

In June 2012, EPA released a Notice of Data Availability (NODA) with some preliminary results from a survey it had conducted to estimate the potential benefits of the Replacement Rule (EPA 2012). The survey presented respondents with background information that included various assertions about the status of fish populations and ecosystems and illustrations concerning the importance of fish and the effects on fish populations of cooling water intake structures used by power plants and other industrial facilities. The survey then presented three choice questions, each of which asked respondents to choose one of three hypothetical policy options—the status quo, for which one would pay nothing, and two hypothetical policy options that would provide hypothetical regional or national improvements in various environmental attributes in exchange for paying some cost in the form of higher electricity and other prices.

EPA conducted its stated preference survey in mail format, sending a questionnaire to the population samples in each of its five target regions: the Northeast, Southeast, Inland, and Pacific areas of the country, as well as a "National" sample drawn from the nationwide population. The address sample for the mail survey was drawn from a database that covers 97 percent of residences in the United States. EPA sent out a total of 6,800 of the regional surveys and 960 of the national surveys, with a target sample size of 2,000 and 288 for the regional and national surveys, respectively. The number of surveys sent to each region differed based on household populations. For example, 1,440 households were surveyed in the Northeast region for target sample size of 417, whereas 2,480 households were surveyed in the Inland region for a target sample size of 732. At the time of EPA's statistical analyses (as reported in the NODA), EPA had received 2,313 completed and returned surveys across all regions. The average response rate was 33 percent.

As discussed in NERA and Desvousges (2012), the EPA survey appears to suffer several significant flaws, including inadequate and misleading biological information, failure to communicate the complexity of potential regional and national 316(b) biological benefits, improper context for policy choice, and hypothetical bias. Moreover, EPA's econometric analysis of the survey results appears to suffer from lack of replication, flawed model selection, and "irrational" respondent behavior. This makes the survey results deeply problematic for use in evaluating the national benefits of the Replacement Rule, let alone for site-specific assessments.

a. Guidance for Site-Specific Assessments

EPA notes that the results of the survey may not be appropriate for site-specific estimates because the conditions at the sites would differ from the conditions described in the survey.

> EPA notes that the preliminary results presented in this NODA are dependent on the background information that was presented to respondents to the stated preference survey, including information about regional and national impacts on aquatic resources both in the baseline and under various policy scenarios. Thus, these preliminary national and regional results are not directly transferable to site specific assessments (EPA 2012, p. 34928).

b. Implications for Potential Non-use Benefits of CWWS and Cooling Towers at IPEC

EPA's survey was developed for national rather than site-specific analysis. As EPA notes, it would not be appropriate to use the national results for site specific analyses. Moreover, as noted above, the survey suffers from many limitations.

5. Overall Implications of EPA Guidance on Site-Specific Assessment of Non-Use Benefits

EPA has provided some guidance for the treatment of non-use benefits in individual site-specific assessments in its various rules and the recent Replacement Rule proposal. Unless specific studies are available, the general guidance is to rely upon qualitative assessments for non-use benefits. In one case, EPA provided specific guidance on the conditions under which monetization should be considered.

With regard to the installation of CWWS and Cooling Towers at IPEC, we are not aware of any study that could be used to develop reliable monetary values for potential non-use benefits. Thus, prior EPA guidance as well as economic criteria suggest that it is not necessary or appropriate to prepare a study of potential non-use benefits in this case. Instead, we provide a qualitative assessment, as outlined below.

D. Assessment of Non-use Benefits from CWWS and Cooling Towers at IPEC

The economics literature on non-use valuation provides some guidance on situations in which non-use values are likely to be significant. We use this literature to structure a qualitative assessment of the likely significance of non-use benefits due to the installation of CWWS and Cooling Towers at IPEC.

1. Economic Criteria on the Likely Significance of Non-use Benefits

In his well-regarded text on measuring environmental and resource values, Freeman (2003) reviews the literature on non-use values, considering the situations in which non-use values are likely to be important/significant:

> Another important question is, when are nonuse values likely to be important? The long literature on nonuse values emphasizes the *uniqueness or specialness of the resource in question* and the *irreversibility of loss or injury*. For example, economists have suggested that there are important nonuse values in preserving the Grand Canyon in its natural state and in preventing the global or local extinction of species and the destruction of unique ecological communities. In contrast, resources such as ordinary streams and lakes or a subpopulation of a widely dispersed wildlife species are not likely to generate significant nonuse values because of the availability of close substitutes. Moreover, the literature does not suggest that nonuse values are likely to be important where recovery from an injury is quick and complete, either through natural processes or restoration (Freeman 2003, pp. 156-157, emphasis added).

Thus, Freeman's (2003) review of this literature suggests two operative criteria for evaluating whether non-use value for fish protection is likely to be important:

1. the resource is unique, in contrast to subpopulations of a widely dispersed wildlife species; and

2. the loss would be irreversible or subject to a long recovery period.

Unless both of these criteria are met, Freeman (2003) suggests that the non-use values are unlikely to be important.[38] Freeman (2003) also notes that SP methods should be used cautiously, as it is extremely difficult to perform such studies well (p. 183).

[38] EPA (2011c) addresses the Freeman criteria in responding to comments it received in 2010 from NERA and WH Desvousges on a draft of the 316(b) survey. EPA references the Bateman et al. (2002, p. 75) statement that there are "no easy rules for determining at the outset" whether non-use values are likely to be significant. However, as noted above in this appendix, Bateman et al. (2002) also state that "[o]ne of the issues to be determined before commissioning a study is the extent to which non-use values are likely to be important" (p. 74). In addition, Bateman et al. (2002) do not imply that non-use values should be monetized regardless of the cost of doing so or

2. Implications for Potential Significance of Non-use Benefits of CWWS and Cooling Towers at IPEC

The Freeman criteria can be used to evaluate the potential significance of non-use changes due to the installation of CWWS or Cooling Towers at IPEC. We consider the two factors (uniqueness and irreversibility) in terms of the changes in T&E species and other species.

a. Threatened and Endangered Species

The information provided above indicates that the installation of CWWS or Cooling Towers at IPEC would not lead to protection of a unique resource as indicated by impacts on T&E species. Although the species themselves could be considered unique, evaluations by NRC as well as expert biologists indicate that the effects of changes due to the installation of CWWS or Cooling Towers at IPEC would be minimal. As noted above, NMFS (2013) concludes that I&E at IPEC "is not likely to jeopardize the continued existence of shortnose sturgeon or the New York Bight...[distinct population segment] of Atlantic sturgeon" (p. 126).

Since the gains due to CWWS and Cooling Towers at IPEC would be ongoing rather than based upon a single event, the irreversibility consideration seems less relevant. Nevertheless, if one considers the long-term sustainability of the species, any adverse effects due to I&E at IPEC presumably would cease at the point at which IPEC would retire.

b. Other Species

The information provided above indicate that I&E at IPEC does not cause substantial harm to the sustainability of other species (including game fish and forage fish) and thus would not lead to loss of a "unique" resource. Instead, the potential gains would be to a "subpopulation of a widely dispersed wildlife species," which Freeman notes would not be likely to generate significant non-use values. Moreover, because any impacts would cease at the point at which IPEC would retire, any adverse effects of IPEC would be reversible.

These considerations indicate that the subpopulations affected by I&E at IPEC would not constitute unique resources and, indeed, any damage would not be irreversible. Thus, by Freeman's (2003) criteria, non-use benefits of adding CWWS or Cooling Towers at IPEC are not likely to be significant as judged by impacts on non-T&E species.

E. Conclusions Regarding Non-Use Benefits of CWWS and Cooling Towers

This appendix summarizes relevant biological information regarding the impacts of reductions in I&E at IPEC from the installation of CWWS or Cooling Towers, and provides a discussion of the guidance from various sources, including EPA and the economics literature, for assessing

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the likely importance of the results. Sensible regulatory policy requires the consideration of the potential nature of non-use benefits and how they might be estimated before committing to a costly and time-consuming study.

non-use benefits. In particular, the various sources provide guidance for determining the circumstances in which it is likely to be important to monetize non-use benefits.

Based on the relevant biological information, the absence of an existing study of non-use values directly related to I&E at IPEC, the absence of a study that could be used appropriately as the basis for benefit transfer, and the various sources of guidance, we conclude that it is appropriate to provide a qualitative evaluation of non-use benefits from CWWS and Cooling Towers at IPEC and that the substantial costs and difficulties of undertaking a SP survey would not be justified. Thus, we evaluate non-use benefits in a qualitative manner.

We conclude that any potential non-use benefits from CWWS and Cooling Towers are not likely to be important or significant based upon economic criteria that have been developed to assess importance and significance in light of the relevant biological information. This conclusion is based upon effects both on T&E species and on the other species for which biological information has been developed.

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Appendix F: Assessment of Potential Indirect Use Benefits

This appendix summarizes our assessment of potential indirect use benefits from CWWS and Cooling Towers at IPEC. As noted in the main report, indirect use benefits are those that contribute indirectly to an increase in welfare for users of the resource. EPA's 316(b) Proposed Rule (EPA 2011) distinguishes indirect use benefits into market and non-market categories. We adopt the same distinction and provide evaluations of potential indirect benefits in these two categories.

A. Market Indirect Use Benefits

Market indirect use benefits are benefits that occur through indirect or secondary effects on marketed goods. As noted, the primary market effects relate to changes in commercial fishing, and the value of the increased commercial harvest to commercial fishermen in particular.

1. Specific Market Indirect Benefit Categories

The following are the specific items listed in EPA's summary of market indirect goods:

1. Increases in commercially valuable species due to an increase in the number of forage fish.[39]
2. Increases in equipment sales, rental, and repair.
3. Increases in bait and tackle sales.
4. Increases in consumer market choices.
5. Increases in choices in restaurant meals.
6. Increases in property values near the water.
7. Increases in ecotourism (charter trips, festivals, and other organized activities with fees such as river walks).

Note that EPA's 316(b) Proposed Rule (EPA 2011) does not provide specific explanations for why these particular items are listed as indirect market use benefits. We distinguish forage fish effects from the other items, which relate to effects on secondary markets as discussed below.

2. Indirect Market Benefits Related to Additional Forage Fish

As discussed in Chapter IV, species without direct commercial (market) value have indirect effects on species with direct use value. In particular, increases in forage fish species serve as

[39] The table does not include the effects of increases in forage fish on commercial species, although it is provided as the example of indirect market benefits (EPA 2011, p. 4-2).

additional food sources for valuable species. We have included these indirect benefits in our analysis by determining the additional striped bass biomass that would result from additional forage fish in the commercial catch estimates. The details of our methodology are described in Appendix C.

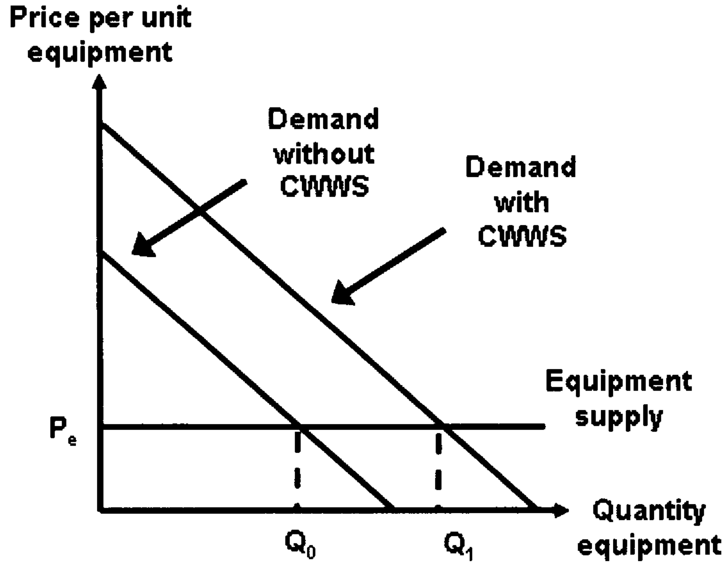
3. Other Indirect Benefit Categories Based Upon Changes in Secondary Markets

When valuing costs and benefits relevant to cost-benefit analysis (CBA), economists distinguish the impacts on primary versus secondary markets. Primary markets are those directly affected by a policy while secondary markets are those that are indirectly affected (Boardman et al. 2011, p. 115, Kolstad 2011, p. 117). In this case, the primary markets are those related to commercial fisheries. As previously noted, the estimates of theoretical benefits based upon additional commercial fish due to CWWS and Cooling Towers are described in the main report and in Appendix C.

The items other than forage fish effects listed above relate to secondary market effects, i.e., impacts on other markets due to the increase in commercial fish as represented by increased landings by commercial fishermen. Many markets might be affected; increases in fishing could increase the demand for fishing boats and equipment, which in turn could increase the demand for aluminum, which could increase the demand for electricity. The question related to benefit assessment is, how many of these markets do we need to evaluate in order to determine the benefits of the policy, in this case the policy to require CWWS and Cooling Towers at IPEC?

These secondary market effects can be ignored so long as prices do not change in these markets (Kolstad 2011, p. 117).[40] Figure F-1 illustrates the situation for an illustrative secondary market (e.g., fishing equipment). As assumed in textbook explanations, the market for fishing equipment is assumed to be a constant cost sector, i.e., one in which the long-run cost of production (and thus the price) does not change as the quantity produced changes (Kolstad 2011, p. 118).

[40] This presumes that there are no market distortions, as Kolstad notes (Kolstad 2011, p. 117, fn. 3).



Source: Illustration as discussed in text.

Figure F-1. Illustrative Secondary Market for Fishing Equipment

Also shown in the figure are two demand curves for commercial fishing equipment, one with no CWWS and one (further to the right) with CWWS. (The change in demand is exaggerated to illustrate the effect.) Note that under the assumption of constant costs, there will be no price effect in the commercial fishing equipment market.[41] Thus, the indirect effects in the commercial fishing market would not lead to additional social benefits (i.e., consumer and producer surplus) other than those included in the primary market. The same logic applies for Cooling Towers.

With regard to the specific items listed above, we would not expect the relatively small increases in additional fishing harvest due to CWWS or Cooling Towers to lead to increases in prices in any of the various secondary markets.[42] This conclusion applies to three of the specific items listed: equipment sales, rentals, and repairs; bait and tackle sales; and ecotourism.

Two of the items listed—consumer market choices and choices in restaurant meals—relate to the possibility that increased harvest could expand consumer opportunities, either in general or in restaurant meals. Such an effect might occur if, for example, the increased commercial catch resulted in introducing some type of fish that was not otherwise available to consumers or restaurant customers. This situation does not seem plausible in the case of CWWS or Cooling Towers, in which the additional commercial fish are not species that would be new to consumers or restaurant customers. Indeed, the fact that our benefit estimates are based upon established commercial fishing prices indicates that these factors are not relevant.

[41] The assumption of constant cost is only in the area of the cost curve relevant to the change in demand.

[42] Even if the prices in the secondary market do change, the change would not lead to indirect benefits as long the changes in the primary market are not measured based upon an assumption that prices of all other goods are held constant, which is the case in our analysis. See Boardman et al. 2011, pp. 119-121.

The situation with respect to property values near the water introduces some complications because of the fact that property can be viewed as a fixed supply, rather than the situation illustrated in Figure F-1. Thus, it would be possible in principal for changes in harvest that were concentrated in particular regions to lead to increases in the value of the land adjacent to the water. This effect seems highly unlikely in this situation given the small changes in harvest and the wide potential area in which the increases would be experienced.

Even if property values increased, however, the increases should not be included in benefit estimates because it would likely lead to double counting. Since the benefit estimates already capture the benefits (i.e., producers' and consumers' surplus) arising from additional fishing harvest, to the extent that these are reflected in potential housing price increases as well, incorporating property values in our analysis would result in our counting these benefits twice. The classical rent theory indicates that where environmental characteristics affect the value of land, these changes will be reflected in land rents / prices (Freeman 2003, p. 354).

In summary, we conclude that omitting the indirect market benefits related to secondary market (and related) effects from the quantified benefits estimates is not likely to significantly affect the overall benefit results. We note that EPA's 316(b) Proposed Rule (EPA 2011) does not estimate the value of these potential benefits.

B. Non-Market Indirect Use Benefits

Non-market indirect use benefits are benefits that occur through indirect or secondary effects on non-marketed goods. As noted, higher catch/harvest for recreational fishermen provides the direct use non-market benefits.

1. Specific Non-Market Indirect Benefit Categories

The following are the specific items listed in EPA's summary of non-market indirect goods.

1. Increase in recreationally valuable species due to an increase in the number of forage fish.43

2. Increase in value of boating, scuba diving and near-water recreational experiences due to enjoying/observing fish while boating, scuba diving, hiking or picnicking.

3. Increase in the value of boating, scuba diving and near-water recreational experiences due to watching aquatic birds fish or catch aquatic invertebrates.

4. Increase in boating, scuba diving and near-water recreational participation.

Note that as with market goods, EPA's 316(b) Proposed Rule (EPA 2011) does not provide specific explanations for why all of these items are listed as indirect non-market use benefits and

[43] As with market indirect benefits, EPA does not list forage fish effects in this table. They are relevant for non-market effects for the same reasons explained by EPA (as noted above) for market effects.

does not estimate the value of these potential benefits. We distinguish forage fish effects from the other items.

2. Indirect Non-Market Benefits Related to Additional Forage Fish

As discussed in Chapter IV, species without direct recreational (non-market) value have indirect effects on species with direct use value. In particular, increases in forage fish species serve as additional food sources for valuable species. We have included these indirect benefits in our analysis by determining the additional striped bass biomass that would result from additional forage fish in the recreational catch estimates. The details of our methodology are described in Appendix D.

3. Other Indirect Benefit Categories Based Upon Non-Market Changes

These other categories are based upon the possibility that the value to participants in various non-market activities (boating, scuba diving and near-water recreational experiences) would be enhanced as a result of the increase in fish due to a particular policy. For example, an increase in the fish populations could in theory lead to an increase in the value of boating and thus in the consumer surplus associated with boating.

In the case of this situation, however, we would not expect the relatively small theoretical increases in fish populations and harvests from CWWS or Cooling Towers at IPEC to lead to a significantly increased value of aquatic and near-water recreational activities, including enjoying or observing fish while boating, scuba-diving, hiking, or picnicking or watching aquatic birds fish or catch aquatic invertebrates.

- Using boating as an example, we would not expect the increased numbers of fish due to CWWS or Cooling Towers to provide a substantially more enjoyable experience boating in the Hudson (or other locations in which additional fish might be present). Moreover, installation of CWWS or Cooling Towers would not lead to a greater diversity of fish (another factor potentially affecting the quality of a boating experience), given that no new species of fish would be available.

- Without an in-depth study of the theoretical impacts of increased fish populations and harvests on the quality of these aquatic activities, it is not possible to determine the potential indirect benefits that might be provided from CWWS or Cooling Towers. As noted, however, since the theoretical increases in fish populations are small relative to overall populations and would be spread over a large area, the additional value of these recreational experiences that would accrue, if any, would also be small. Thus, we conclude that omitting this potential benefit category from the quantified benefits estimates is not likely to significantly affect the overall results.

- Similarly, we would not expect the relatively small theoretical increases in fish populations and harvests from CWWS and Cooling Towers at IPEC to lead to a significantly increased participation in boating, scuba-diving, bird-watching, or other aquatic and near-water recreational activities. Therefore, as in the case of the value of aquatic activities, we conclude that omitting this potential benefit category from the quantified benefits estimates is not likely to significantly affect the overall results.

C. Conclusions Regarding Indirect Use Benefits of CWWS and Cooling Towers

This appendix provides an assessment of the significance of indirect use benefits arising from the installation of CWWS or Cooling Towers at IPEC, primarily based on economic theory and guidance from the economics literature. The following are our conclusions on the specific categories of potential indirect effects identified in EPA 2011 and evaluated above.

- Indirect effects due to additional forage fish (both forage species and un-harvested game fish) are included in the benefit assessments, as discussed in the report.
- Indirect secondary market effects are not likely to be significant because they are not likely to lead to price effects that could lead to additional consumers' or producers' surplus.
- No significant additional market opportunities would result from CWWS or Cooling Towers effects.
- Effects on property values due to effects of CWWS and Cooling Towers on fish populations are not likely to be significant and, even if they were, should not be included because of the likelihood of double counting.
- Effects on the value of non-market activities due to CWWS or Cooling Towers are not likely to be significant given the small effects on fish populations.
- Effects on participation in non-market activities due to CWWS or Cooling Towers are not likely to be significant given the small effects on fish populations.

In summary, we conclude that apart from forage fish effects, no potential indirect use benefits from CWWS or Cooling Towers are likely to be significant or change any of the conclusions in the report.

D. References

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Appendix G: Background on Monte Carlo Analysis

This appendix provides background information on the Monte Carlo analysis. Monte Carlo analysis allows us to use information on the probability distributions of individual cost and benefit components to develop information on the uncertainties of the net costs (*i.e.*, total costs less total benefits) of each fish-protection alternative considered in this assessment. Note that if benefits exceed costs, this calculation yields a distribution of the net benefits rather than the net costs.

This appendix first provides an overview of the steps in a Monte Carlo analysis. The second section discusses the nature of the Monte Carlo results. The specific methodology and results for IPEC are presented in Chapter VI of the report.

A. Overview of Monte Carlo Analysis

The net costs (or net benefits) of the fish-protection alternatives depend upon the values of the individual cost and benefit components. The underlying inputs to the costs and benefits assessments are not known with certainty, so the results (net costs or net benefits) are subject to uncertainty. Monte Carlo analysis provides a means of translating the uncertainties regarding the various components into an assessment of the uncertainty regarding the net costs, by generating probability distributions of the results.

1. Simple Example

Consider a simple example in which one wants to determine the probability of obtaining various values when two fair dice are rolled simultaneously and their outcomes summed together. Because each die has numbers from 1 to 6, the possible sums range from 2 to 12. Analytically, we know that the probability of a sum can be determined by calculating the likelihood based upon the underlying probabilities. For example, a sum equal to 2 can be obtained only if both dice come up as "1". The probability that a die comes up as "1" is 1/6. Therefore, the likelihood of getting a sum equal to 2 is $\frac{1}{6} \times \frac{1}{6} = \frac{1}{36}$. The probability distribution of the sum of the two dice provides the probability of each possible outcome (2 to 12). In contrast, there are six different possible ways that the sum of the two dice could sum to 7, so the probability of that outcome is

$$\frac{6}{36} = \frac{1}{6}$$

The Monte Carlo simulation approach can be used to estimate the probability distribution of the sum of the two dice. The two dice would be rolled many times and the frequency (*i.e.*, fraction of the rolls) with which the sum of the two dice equals each of the possible numbers would be calculated. If many rolls were used, the probability of achieving a given sum (*e.g.*, 2) could be estimated with high precision. Moreover, we could use the same information to estimate the probability that the sum could be equal to or less than a given number (*e.g.*, 8) by using the same Monte Carlo information. A computer can be used to develop the distribution by specifying the probability distribution of each of the two dice (*i.e.*, equal chance of getting integers between 1 and 6) and the value of interest (*i.e.*, sum of two dice) and using the computer to "roll the dice" over and over again.

This example involves a simple situation in which there are two inputs (the value of the first die and the value of the second die), a simple probability distribution for each of the two inputs, no interaction among the inputs (*i.e.*, the value of the first die is independent of the value of the second die), and one outcome of interest (*i.e.*, the sum of values of the two dice). But the same approach can be used to calculate the probability distribution of outcomes or results in much more complicated situations.

2. Steps in Monte Carlo Analysis

This section outlines the basic steps for conducting a Monte Carlo analysis. The EPA's *Guiding Principles for Monte Carlo Analysis* document (EPA 1997) provides a good discussion of the general framework for conducting Monte Carlo analysis. Although the document was prepared within the context of risk assessments (and focuses on uncertainty and variability in estimates of exposure or risk related to human health and ecological risk), the general principles discussed are applicable to the present context as well. In the general discussions that follow, we also provide some illustrative examples relevant to the uncertainty characteristics for the fish-protection alternatives.

Monte Carlo analysis as applied to the determination of net costs for fish-protection alternatives at IPEC involves three basic steps:

1. Specify the model, *i.e.*, the inputs that determine the costs and benefits;

2. Develop probability distributions for the uncertain inputs of interest; and

3. Run the Monte Carlo probabilistic model, calculating the probability distribution of the outputs (*i.e.*, net costs).

We discuss each of these steps in more detail below.

a. Specify the Model

The first step in performing the cost-benefit analysis is to set up the model that takes the inputs and calculates the present values of costs, benefits, and net costs (or net benefits). The results in Chapter V were developed using such a model.[44]

One can think of the results of the model as the "most likely" results, assuming that the values of the inputs are the "most likely" values for those inputs. However, when one or more of the inputs is subject to uncertainty, the outcome itself is subject to uncertainty. A Monte Carlo model

[44] Since the model and results do not account for uncertainty, they are typically referred to as "deterministic" or "non-stochastic." In a deterministic model, one gets the same (*i.e.*, deterministic) results regardless of the number of times the model is recalculated (given the same set of inputs). In contrast, a Monte Carlo model provides a range of possible results, since the inputs are varied.

allows us to characterize the uncertainty in the outcome based on knowledge of the uncertainty of the inputs. For example, instead of using a single, fixed value for the electricity price in a given period, a probability distribution of possible electricity prices would be used to capture the range of (uncertain) cost values. Allowing for variability in the electricity prices would lead to variability in the outcome of the model, *i.e.*, the net costs or net benefits.

b. Develop Probability Distributions for Key Uncertain Variables

This second step is to develop information on the uncertainty regarding various cost and benefit inputs. This step involves two basic stages: (1) selecting the input variables for which probability distributions will be developed; (2) specifying the nature of the probability distribution of these input variables to capture the underlying uncertainty; and (3) specifying potential correlations among the uncertain variables.

The analysis should focus on key variables, taking into account the difficulty of characterizing their uncertainty. It is of course not possible to account for every source of uncertainty or variability. As EPA notes in its guidelines for Monte Carlo analysis,

> Although specifying [probability] distributions for all or most variables in a Monte Carlo analysis is useful for exploring and characterizing the full range of variability and uncertainty, it is often unnecessary and not cost effective. (EPA 1997, p. 12)

Results from the (deterministic) model and sensitivity analyses can help identify key variables for inclusion in the Monte Carlo analysis. As the EPA (1997) document points out, from a computational standpoint, a Monte Carlo model usually includes a mix of point estimates (*i.e.*, single values without a distribution) and distributions for the inputs of the model.

The next important stages are to characterize the probability distributions for each of the key variables, including the probability distributions for each input and potential correlation among the inputs. The probability distributions should capture the possible values and/or ranges for each of the variables as well as the likelihood that each particular value will be observed. Various levels of sophistication are possible to describe the probability distributions. In the ideal case, the exact shapes and parameters of the probability distributions for the variables are known (for example, the distributions could be uniform distributions, normal distributions, triangular distributions, lognormal distributions, *etc.*). However, such information often is not available. Monte Carlo simulation models typically rely on distribution information based on historical data, informed estimates by industry experts and/or relevant publications, or a combination of the various sources.

When ample historical data are available, the minimum and maximum values that have occurred in the past often are used to determine the variable range.[45] Identifying the shape of the

[45] Such an approach may not always be appropriate, particularly if only limited historical data are available. For example, consider N independent random variables drawn from a uniform distribution on the unit interval. The expected value of the minimum observed random variable is 1/(N+1), and the expected maximum is N/(N+1). If

probability distribution within that range is a more challenging task, and its feasibility and applicability depend on the number of past observations that are available. Statistical software packages used to run Monte Carlo simulations are typically equipped to produce distribution estimates by grouping the raw data in a frequency histogram, fitting the observed frequencies to a large number of standard distributions, and using a chi-squared test or other goodness-of-fit tests to rank the various distribution curves by order of fit. If uncertainties arise because inputs are being estimated using econometric models, other approaches may be available: in general, due to central limit theorems, the distribution of estimates obtained using econometric methods converge to a multivariate normal distribution as the number of observations used in the estimation becomes large.

If historical data are not available or are not adequate to estimate the probability distribution of a particular variable, Monte Carlo models typically rely on expert judgments for selecting and analyzing alternate plausible scenarios for the variables of interest. For example, we might "fit" a given set of prices which are strictly positive to a lognormal distribution, which are only defined for positive values. As another example, in evaluating potential construction costs of the different alternatives for which site-specific historical data are not available, we might rely on engineering estimates for the main uncertain cost components and then apply a log-normal distribution, which is commonly used for engineering cost uncertainties.

An important point to address when determining the distributions of uncertain variables is to consider correlation or dependency between input variables, the third stage outlined above. Some of the uncertain variables may be correlated with one another, and thus the distributions are not independent. An example might be CO_2 and NO_x allowance prices projections used to determine power costs from implementation of the fish-protection alternatives. Both CO_2 and NO_x prices are influenced by fuel prices as well as weather patterns/fluctuations. It is therefore reasonable to expect these variables to be correlated. Correlations may also exist over time as well as across variables (*e.g.*, electricity prices in one period may be correlated with those in the next period). Important temporal relationships should be included in the information used in the Monte Carlo analysis.

c. Run the Monte Carlo Model

Once the probability distributions of the key inputs are specified (including potential correlations), the Monte Carlo simulation is run. Typically, the simulation is run by computers using data in spreadsheet or statistical programs.

The Monte Carlo simulation model asks the computer to recalculate the outcome of the model over numerous iterations, each time using a randomly selected set of input values based on the specified probability distributions. In our analysis, each simulation run generates a net costs value which is governed by the input probability distributions specified in the model. The number of simulations, or the calculation of net costs in this case, is repeated a large number

N is "large," then the approximation to the endpoints of the range for the random variable will be good. If N is "small" (*e.g.*, if N is only two or three), then the approximation will be poor.

(e.g., 1,000) of times. The mean and variance of net costs can be calculated across multiple simulation runs.

In addition to mean and variance estimates, the result of the Monte Carlo simulations also allows calculation of the probability distribution of net costs. Graphical analysis is often used to show the range of possible net costs (or net benefits), the distribution of net costs within this range (the probability density function (PDF)), the most likely outcome (the mode of the distribution), and the mean and variance of the distribution..

3. Decision Rules Applied to the Results of a Monte Carlo Analysis

In benefit-cost analysis, the general rules are (1) to undertake only projects with positive net benefits, or, equivalently those with negative net costs (*i.e.*, those for which benefits exceed costs), and (2) given a choice among several competing alternatives, to choose the one that maximizes total net benefits (or minimizes net costs). When uncertainty is taken into account, usually there is no single value for net benefits. Instead, there is a range of possible net benefits, and a probability distribution that gives the likelihood of each net benefit value within that range. The decision is "easy" only if the minimum of the range of net benefits is greater than zero (undertake the project) or if the maximum of the range of net benefits is negative (do not undertake the project). But when a project shows some probability for positive outcomes as well as some probability for negative outcomes, the decision rests on the risk predisposition of the investing parties. The general rules in cases like this are to accept stand-alone projects when their *expected* net benefits are positive, and in the case of multiple projects, to choose the one with highest expected net benefits while also paying attention to the relative risk of each alternative captured by its variance. Expect net benefit is simply the mean of the distribution of outcomes.

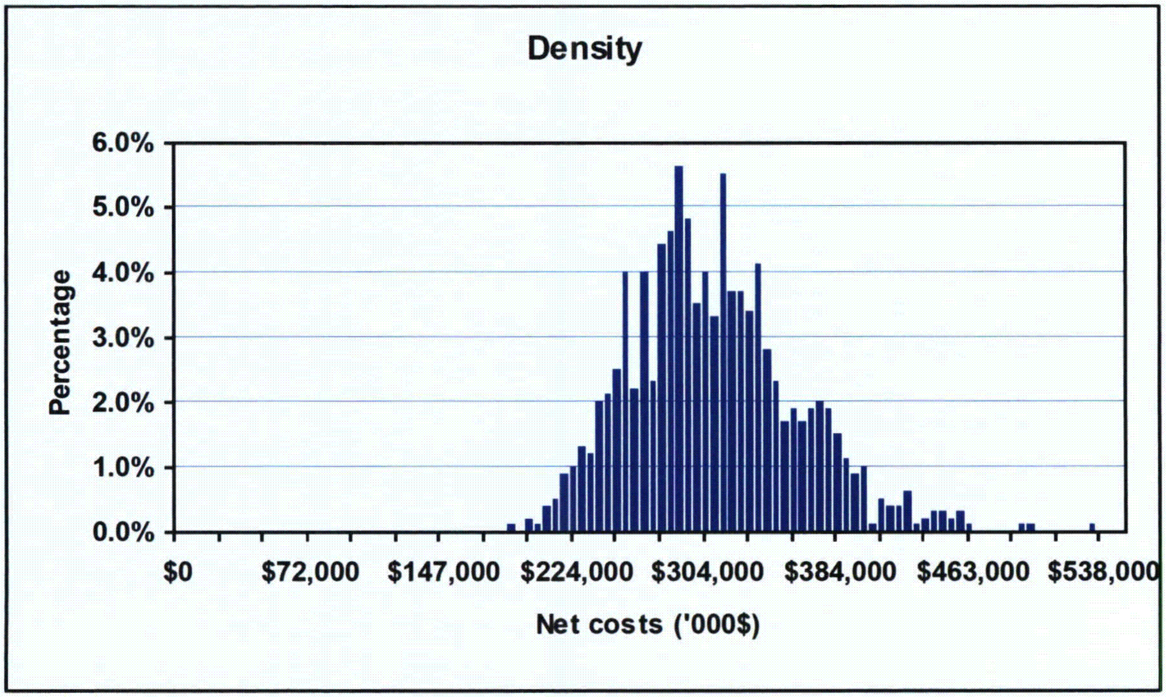
B. Reporting of Monte Carlo Simulation Results

This section discusses the nature of the Monte Carlo results. As noted in the EPA "*Guiding Principles*" document, "[a]ccounting for the important sources of uncertainty should be a key objective in Monte Carlo analysis. However, it is not possible to characterize all the sources of uncertainties associated with the models and data" (EPA 1997, p.16). Based on the results of the base-case analysis, the various input parameters discussed in Chapter V are important sources of uncertainty and therefore were included in the Monte Carlo analysis in this case.

A probability density function (PDF) and graphs of net costs were developed for each of the fish-protection alternatives, as reported in Chapter V. Figure G-1 shows an example PDF. The EPA "*Guiding Principles*" document lists the following advantages of the PDF, which in this case shows possible values of net costs (or net benefits) (on the horizontal axis) and the respective probabilities (or densities) on the vertical axis. EPA states that "[PDF plots are] useful for displaying:

- "the relative probability of values;
- "the most likely values (*e.g.*, modes);

- "the shape of the distribution (*e.g.*, skewness, kurtosis); and
- "small changes in probability density." (EPA 1997, pp. 17-18)



Note: Relative frequency is the probability of a simulation draw occurring within an interval (the number of simulation draws in an interval over the total number of draws).

Source: Hypothetical

Figure G-1. Example of a PDF

C. References

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Appendix H: Costs and Benefits of CWWS and Cooling Towers Disregarding Air Permit Considerations

This appendix provides information on the costs and benefits of Cooling Towers under the assumption that there are no constraints on operating the towers due to air permit considerations. As discussed in the report body, TRC (2009) concluded that Cooling Towers similar to those proposed by Tetra Tech (2013) could not operate at substantial times during the year because of the need to meet air emissions permitting requirements. For illustrative purposes, this appendix provides information on the costs and benefits of Cooling Towers if they could be operated continuously. The information is based on currently available engineering inputs from ENERCON and biological inputs from ASAAC. Cost and benefit estimates for cylindrical wedgewire screens (CWWS) are also provided for the purpose of comparison.

A. Costs of Continuous Operation of Cooling Towers

1. Methodology and Assumptions

In the body of our report, we applied Tetra Tech's (2013) estimates for Cooling Towers to a scenario where the Cooling Towers are constrained by local air quality regulations and do not operate continuously. ENERCON (2010) notes that it has only performed a detailed engineering analysis of a Cooling Towers alternative without the constraints of air permitting requirements; it expects the capital costs for a plant capable of variable operation to be at least as large as for continuous operation.

In this appendix, we use the Tetra Tech (2013) estimates to calculate the expected costs for the construction and operation of Cooling Towers that operate continuously. Although capital costs are assumed to be the same in both scenarios (for lack of better information on the higher capital costs of intermittent operation), both O&M costs and ongoing power losses would be higher under continuous operation, since both are incurred during plant operation. Based on the operating schedule in ENERCON (2010), we revise O&M costs and ongoing power losses in proportion to the expected operation of the Cooling Towers.

We use the methodology described in Chapter III of the main benefit-cost report to estimate the costs of continuously operated Cooling Towers. We assume the same timeline for the construction and installation of the Cooling Towers, based on information in Tetra Tech (2013).

2. Cost Results

The estimated present values of costs for CWWS and Cooling Towers are shown in Table H-1. Costs for CWWS are unchanged from the body of the report. Specifically, the screens cost $169.5 million using a 3 percent discount rate and $123.9 million using a 7 percent discount rate, whereas the Cooling Towers cost about $1.2 billion using a 3 percent discount rate and $760.5 billion using a 7 percent discount rate. To ensure comparability with the results presented in the body of this report, no cost contingency is assumed for both alternatives. Cooling Tower capital costs and outage costs remain unchanged under the assumption of continuous operation. The increased total cost of the Cooling Towers alternative is due to increases in O&M and Electricity costs that reflect the increased usage of the Cooling Towers. On average, these variable costs are approximately 7 to 8 times higher under the assumption of continuous operation.

Table H-1. Estimated Total Costs of CWWS and Continuously Operated Cooling Towers

	Discount Rate	
Technology	**3%**	**7%**
CWWS		
Construction	$173.9	$126.2
O&M	N/A	N/A
Electricity	-$4.4	-$2.4
Total	$169.5	$123.8
Cooling Towers		
Construction	$595.2	$393.6
O&M	$0.8	$0.3
Electricity	$634.6	$366.6
Total	$1,230.6	$760.5

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars.
Source: NERA calculations as explained in text

B. Benefits of Continuously Operation of Cooling Towers

1. Methodology and Assumptions

We used the methodology described in Chapter IV of the report to estimate the monetized potential benefits of the continuously operated Cooling Towers alternative. ASAAC (2013) provides estimates of the biological losses in terms of harvest and catch under the assumption that the Cooling Towers would operate continuously under historical water flows at IPEC.

Table H-2 shows estimated theoretical annual fishery harvest losses due to I&E under various CWIS configurations. CWWS are capable of preventing approximately 95 percent of theoretical fish harvest losses, with Cooling Towers preventing approximately 97 percent of losses. These calculations indicate that when finally installed and if operating continuously, Cooling Towers would result in somewhat greater theoretical gains in harvest, although the difference between CWWS and Cooling Towers is relatively small.

Table H-2. Estimated Annual Fishery Harvest Losses Due to I&E at IPEC (kg)

	Impingement	Entrainment	Total
Modeled Species			
Regulatory Baseline	29,600	238,933	268,533
Current Configuration	1,807	98,754	100,561
CWWS	69	13,040	13,109
Cooling Towers	76	6,005	6,081

Source: ASAAC (2013)

Table H-3 shows annual fishery harvest gains relative to the current configuration. The calculations show that Cooling Towers are slightly more effective than CWWS on an annual basis if one assumes Cooling Towers can operate continuously. As discussed below, however, when account is taken of the earlier installation of CWWS, CWWS would result in greater cumulative theoretical gains than Cooling Towers.

Table H-3. Estimated Annual Fishery Harvest Gains Relative to the Current Configuration (kg)

	Impingement	Entrainment	Total
Current Configuration*	27,793	140,179	167,972
CWWS	1,738	85,714	87,452
Cooling Towers	1,731	92,749	94,480

Source: NERA calculations as explained in text
* Current Configuration harvest gains are relative to the regulatory baseline

2. Aggregate Benefit Results

The estimated present values of aggregate theoretical benefits for the Cooling Towers and CWWS alternatives are shown in Table H-4. (As noted in the report, we refer to the benefits as theoretical benefits because of expert biological information that fish harvests would not actually be increased with CWWS and Cooling Towers in place.) These results show that the theoretical benefits of Cooling Towers are smaller than CWWS even when Cooling Towers are assumed to operate continuously during the year, not accounting for limitations due to air permit considerations. This result reflects the fact that CWWS would be put in place years before Cooling Towers and thus would generate additional years of theoretical benefits before Cooling Towers would be in place. Using a discount rate of 3 percent, CWWS provide about $1.3 million greater aggregate benefits than Cooling Towers; using a 7 percent discount rate, the difference is $0.9 million.

Table H-4. Estimated Total Theoretical Benefits of CWWS and Continuously Operated Cooling Towers

	Discount Rate	
Alternative	**r = 3%**	**r = 7%**
CWWS		
Commercial	$0.3	$0.1
Recreational	$11.1	$6.0
Total	$11.3	$6.1
Cooling Towers		
Commercial	$0.2	$0.1
Recreational	$9.8	$5.1
Total	$10.0	$5.2

Note: All values are present values as of January 1, 2013 in millions of constant 2012 dollars.
Source: NERA calculations as explained in text