FILED
October 21, 2016
INDIANA UTILITY
REGULATORY COMMISSION

**STATE OF INDIANA**

**INDIANA UTILITY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY (I&M), AN INDIANA CORPORATION, FOR APPROVAL OF A CLEAN ENERGY PROJECT AND QUALIFIED POLLUTION CONTROL PROPERTY AND FOR ISSUANCE OF CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR USE OF CLEAN COAL TECHNOLOGY; FOR ONGOING REVIEW; FOR APPROVAL OF ACCOUNTING AND RATEMAKING, INCLUDING THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF SUCH PROJECT THROUGH I&M'S CLEAN COAL TECHNOLOGY RIDER; FOR APPROVAL OF DEPRECIATION PROPOSAL FOR SUCH PROJECT; AND FOR AUTHORITY TO DEFER COSTS INCURRED DURING CONSTRUCTION AND OPERATION, INCLUDING CARRYING COSTS, DEPRECIATION, TAXES, OPERATION AND MAINTENANCE AND ALLOCATED COSTS, UNTIL SUCH COSTS ARE REFLECTED IN THE CLEAN COAL TECHNOLOGY RIDER OR OTHERWISE REFLECTED IN I&M'S BASIC RATES AND CHARGES.** | ) | OFFICIAL EXHIBITS<br><br>**CAUSE NO. 44871**<br><br>IURC<br>PETITIONER'S<br>EXHIBIT NO. 4<br>3-1-17 AT<br>DATE REPORTER |

**SUBMISSION OF DIRECT TESTIMONY OF**
**<u>SCOTT C. WEAVER</u>**

Indiana Michigan Power Company, by counsel, hereby submits the direct testimony and attachments of Scott C. Weaver.

Jeffrey Peabody

Teresa Morton Nyhart (Atty. No. 14044-49)
Jeffrey M. Peabody (No. 28000-53)
Barnes & Thornburg LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Phone: (317) 231-7716 (Nyhart)
(317) 231-6465 (Peabody)
Fax: (317) 231-7433
Email: tnyhart@btlaw.com
jpeabody@btlaw.com

Attorneys for Indiana Michigan Power Company

## CERTIFICATE OF SERVICE

The undersigned certifies that the foregoing was served upon the following via electronic email, hand delivery or First Class, United States Mail, postage prepaid this 21st day of October, 2016 to:

Office of Utility Consumer Counselor
PNC Center
115 W. Washington St., Suite 1500 South
Indianapolis, Indiana 46204
infomgt@oucc.in.gov.

Jeffrey M. Peabody

Teresa Morton Nyhart (No. 14044-49)
Jeffrey M. Peabody (No. 28000-53)
BARNES & THORNBURG LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Nyhart Phone: (317) 231-7716
Peabody Phone: (317) 231-6465

Attorneys for INDIANA MICHIGAN POWER COMPANY

EXHIBIT I&M-________

STATE OF INDIANA

# PRE-FILED VERIFIED DIRECT TESTIMONY

OF

SCOTT C. WEAVER

ON BEHALF OF

INDIANA MICHIGAN POWER COMPANY

**PRE-FILED VERIFIED DIRECT TESTIMONY OF SCOTT C. WEAVER ON BEHALF OF INDIANA MICHIGAN POWER COMPANY**

## I. INTRODUCTION

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

A. My name is Scott C. Weaver, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation ("AEPSC") as Managing Director-Resource Planning and Operational Analysis. AEPSC supplies engineering, financing, accounting and similar planning and advisory services to the ten electric operating companies of the American Electric Power System (collectively, "AEP"), including Indiana Michigan Power Company ("I&M" or "Company").

## II. BACKGROUND

**Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. I received a Bachelor of Business Administration Degree in Accounting from Ohio University in 1981, and a Master of Business Administration from the same university in 1985. In addition, in 1996 I completed both the American Electric Power System Management Development Program at The Ohio State University, as well as The Darden Partnership Program at the Darden Graduate School of Business Administration, at the University of Virginia.

I have over 35 years of experience with AEP. I was employed by AEPSC in 1980 as an Associate Forecast Analyst in the Controllers

Department (now Corporate Planning and Budgeting Department), was subsequently named Assistant Financial Analyst in 1983, Financial Analyst in 1986, Senior Financial Analyst in 1987, and Senior Administrative Assistant II in 1990. In 1991, I transferred to the AEPSC Fuel Supply Department as Manager-Administration. I was subsequently named Manager-Administration and Purchasing in 1994 and Director of Power Generation Business Planning and Financial Management in 1996. I transferred to the AEP Wholesale business unit in 2000 as Manager-Business Planning and in January, 2003 transferred back to the Corporate Planning and Budgeting Department as Director of Operational Analysis. I assumed my present position in May 2003.

**Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR–RESOURCE PLANNING AND OPERATIONAL ANALYSIS?**

A. I am responsible for the supervision and administration of long-term generation resource planning and supply-side operational analysis for AEP. In such capacity, I coordinate the use of short- and long-term generation production costing and other resource planning models used in the ultimate development of operating and capital budget forecasts for I&M and its parent, AEP, regularly monitor actual performance, and review the preparation of forecasted information for use in regulatory proceedings.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS REGULATORY COMMISSION?**

A. Yes. I offered testimony before this Commission in 2013 on behalf of the Company in Cause No. 44331, which sought a certificate of public convenience and necessity ("CPCN") for the installation of dry sorbent injection ("DSI") technology and associated equipment at the Company's Rockport Plant. Most recently, I offered testimony on behalf of I&M in Cause No. 44523; which also sought a CPCN for the installation of selective catalytic reduction ("SCR") technology for Rockport Unit 1. In addition, over the last ten years I will have offered resource planning-related testimony on behalf of AEP operating company affiliates before eight other state commissions: Arkansas, Kentucky, Louisiana, Michigan, Oklahoma, Texas, Virginia, and West Virginia.

## III. PURPOSE OF TESTIMONY

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS FILING?**

A. The purpose of this testimony is to present economic analyses performed on behalf of the Company regarding installation of SCR technology on Rockport Unit 2. In particular, my testimony will:

1) evaluate the cost and feasibility of an option to retire and replace Rockport Unit 2, an assessment required by Ind. Code § 8-1-8.7-3(b)(7);

2) describe the modeling process undertaken to evaluate the relative economics of the alternative Rockport Unit 2 disposition options, including a discussion around the major input parameters and key drivers; chief among them the anticipated long-term price of natural gas and energy as well as carbon dioxide ("$CO_2$") that could impact the Rockport Unit 2 dispatch priority, an assessment required by Ind. Code § 8-1-8.7-3(b)(8);

3) affirm that the analysis undertaken assessing these Rockport Unit 2 disposition options is consistent with I&M's 2015 Integrated Resource Plan ("IRP") submitted to this Commission on November 2, 2015; and

4) discuss the results of these economic modeling analyses and the determination that a near-term decision to retrofit Rockport Unit 2 by December 31, 2019 with SCR technology and associated equipment for the reduction of nitrogen oxides ("$NO_X$") is reasonable and would further a course of action around this unit that could ultimately save I&M and its customers over $300 million versus an option that would not perform that retrofit.

**Q. ARE YOU SPONSORING ANY ATTACHMENTS?**

A. Yes. I am sponsoring the following attachments:

- Attachment SCW-1 – Overview of resource planning-related criteria considered in the analyses.
- Attachment SCW-2 – Key long-term fundamental commodity pricing projections used in the analyses.
- (CONFIDENTIAL) Attachment SCW-3 – Major modeling input costs and operating parameters for unit disposition options.
- Attachment SCW-4-1 and SCW-4-2 – Summary of Rockport 2 unit disposition alternative economic analyses over the long-term life cycle study period evaluated, all under unique commodity pricing scenarios (Attachments SCW-4A through SCW-4E).
- Attachment SCW-5 – Summary of Rockport 2 unit disposition alternative analyses results examined over a shorter timeframe which would demonstrate the significant optionality afforded by retrofitting the unit with SCR technology prior to the possible future installation of a dry scrubber by December 2028, or prior to the potential return of the unit to its Lessors by December 2022.
- Attachment SCW-6 – A comparison of economic analyses that assessed possible Rockport Unit 2 disposition alternatives included in I&M's recently-submitted 2015 IRP.

**Q. WERE THESE ATTACHMENTS PREPARED OR ASSEMBLED BY YOU OR UNDER YOUR DIRECTION OR SUPERVISION?**

A. Yes they were. As I will describe in this testimony, other functional organizations within I&M and AEPSC were involved in this evaluation process. The role I served was one of coordinating the attendant economic modeling effort and, ultimately, validating, documenting, and internally communicating this process and the results.

**Q. PLEASE DESCRIBE THE CONTENTS OF ATTACHMENT SCW-1.**

A. Attachment SCW-1 offers a broader overview of some of the other resource planning-related criteria that are necessarily introduced and considered as part of this evaluation of alternative options surrounding Rockport Unit 2, but that largely serve as a backdrop. The following direct testimony focuses more specifically on the discrete economic evaluations performed that led to the Company's conclusions and recommendations.

## IV. ROCKPORT UNIT 2 DISPOSITION OPTIONS

**Q. WHAT ALTERNATIVES WERE ANALYZED WITH RESPECT TO THE DISPOSITION OPTIONS FOR ROCKPORT UNIT 2?**

A. As represented on the following **TABLE 1**, two alternative options—with one of those alternatives posing two sub-options—were modeled with respect to I&M's disposition options associated with the Rockport Plant and, specifically, Rockport Unit 2:

**TABLE 1**

***OPTION #1 - Install SCR on Rockport Unit 2***

**Option #1A:** Retrofit Rockport Unit 2 with SCR technology and associated equipment ("Rockport Unit 2 SCR Project") by December 31, 2019, and enter into a Rockport Lease renewal arrangement for Unit 2 that would provide for its continued operation through retirement at the end of the unit's useful life.

*With that, for purposes of only this I&M long-term economic evaluation process, assume...*

- Rockport Unit 1 retrofit with SCR by December 31, 2017, as planned, and subsequently retrofit both Rockport units with Dry Flue Gas Desulfurization ("DFGD") technology by December 31, 2025 (Unit 1), and December 31, 2028 (Unit 2); and
- add ash pond, effluent waste-water treatment, and other U.S. Environmental Protection Agency ("EPA")-required equipment and investments at the Rockport Station by approximately the 2019-2021 timeframe.

**Option #1B:** Retrofit Rockport Unit 2 with SCR technology by December 31, 2019, and return the unit to the Lessor by the December 2022, Rockport Lease termination date.

*With that, for purposes of only this I&M long-term economic evaluation process, assume...*

- Rockport Unit 1 retrofit with SCR by December 31, 2017, as planned, and retrofit *only* Rockport Unit 1 with DFGD technology by December 31, 2025;
- replace I&M's (85%) ownership/entitlement share of Rockport Unit 2 power and energy with *some combination of* similar-sized, new-build natural gas combined cycle units; natural gas simple-cycle combustion turbine units; aeroderivative units; combined heat and power generation; as well as new renewable (i.e., wind and solar) and incremental demand–side management resources by approximately January 1, 2023; and
- add ash pond, effluent waste-water treatment, and other U.S. EPA-required equipment and investments at the Rockport Station by approximately the 2019-2021 timeframe.

***OPTION #2 - Do NOT install SCR on Rockport Unit 2***

**Option #2:** Do not proceed with the Rockport Unit 2 SCR Project, but rather return the Unit to the Lessors by December 31, 2019, before the 2022 termination date in the Rockport Lease.

*With that, for purposes of only this I&M long-term economic evaluation process, assume…*

- incur payment, according to the terms of the Lease, of the Lease Termination Value effective as of that date;
- retrofit Rockport Unit 1 *only* with SCR by December 31, 2017, as planned, and, likewise, retrofit *only* Rockport Unit 1 with DFGD technology by December 31, 2025;
- replace I&M's (85%) entitlement share of Rockport Unit 2 power and energy with some combination of similar-sized, new-build CC units; CT units; AD units; CHP generation; as well as new renewable and incremental DSM resources by approximately January 1, 2020; and
- add ash pond, effluent waste-water treatment, and other U.S. EPA-required equipment and investments at the Rockport Station by approximately the 2019-2021 timeframe.

**Q. WHAT IS THE SIGNIFICANCE OF THE DECEMBER 31, 2019 ROCKPORT 2 UNIT DISPOSITION DATE IDENTIFIED UNDER MODELED "OPTION #2"?**

A. December 31, 2019, represents the required retrofit in-service date for the Rockport Unit 2 SCR as set forth within the terms of the Third Joint Modification to the Consent Decree ("Modified Consent Decree"). Based on the testimony of Company witness Hendricks, if the Rockport Unit 2 SCR Project is not installed by that date the unit cannot continue to operate. Hence, as indicated by Company witness Chodak, this condition would necessitate that the Rockport Lease would be terminated, with I&M and AEP Generating Company ("AEG") then obligated to pay the requisite Termination Value as set forth in the Lease. Such Termination Value as of December

2019 being estimated at $715.7 million[1] as provided to me by Mr. Chodak.

The specific terms of the Modified Consent Decree, as well as other existing and potential future environmental regulations, are discussed in detail in the testimony of Mr. Hendricks.

The Rockport Lease Agreement and its applicable terms and conditions, including end-of-term criteria, are discussed in the testimony of Mr. Chodak.

**Q. WHY IS IT PRACTICAL TO CONSIDER, FOR PURPOSES OF THIS ECONOMIC ANALYSIS, A SCENARIO (OPTION #1B) WHERE ROCKPORT UNIT 2 WOULD ONLY BE AVAILABLE TO I&M FOR THREE YEARS AFTER THE INSTALLATION OF SCR TECHNOLOGY?**

A. Given the current relative uncertainty of any end-of-lease-term disposition—one that may result in the exercise of an available Lease renewal option—the most reasonable, and least speculative, assumption for purposes of this analytical exercise would be to simply assume the unit would be returned to the Lessors at the Rockport Lease termination date. As explained further by Company witness Chodak this assumption does not preclude the Company from pursuing a Rockport Lease renewal afforded under the Rockport Lease.

In sum, Option #1B offers a "worst-case" view of an SCR retrofit "only" scenario, vis-à-vis Option #2 which would not proceed with the Rockport Unit 2 Retrofit Project. Option #1B is considered "worst case" because any Rockport Lease renewal would be established under terms that *must* result in more favorable long-term economics than the "Return at Termination

[1] This represents the <u>total</u> estimated Termination Value, with I&M's "85% (ownership and AEG purchase) share" being $608.4 million.

(December 2022)" option available to the Company under Option #1B as defined. Therefore, in spite of any practical considerations of potentially operating Rockport Unit 2 for a period of only three years after the installation of a major environmental retrofit, Option #1B essentially sets the minimum bound for purposes of determining the economic advantage to I&M's customers of proceeding with the Rockport Unit 2 SCR Project versus an approach that would *not* install the SCR and require the early termination of the Rockport Lease.

**Q. WHAT WOULD BE THE ECONOMIC IMPLICATION OF INVESTING IN AN SCR BY DECEMBER 2019, WITH THE POSSIBILITY OF RETURNING THE UNIT TO THE LESSOR IN APPROXIMATELY 3 YEARS?**

A. For Option #1A and #1B, the modeled cost-recovery period for the capital cost associated with the Rockport Unit 2 SCR Project to be completed in December 2019 was assumed to be 10 years (*i.e.*, by end-of-2029). This period is consistent with the allowable depreciation period under Ind. Code § 8-1-2-6.7, as described by Company witness Williamson.

However, recognizing in Option #1B that I&M's potential continued operation of Unit 2 could be limited to the end of the Rockport Lease term, a sensitivity analysis was also performed that would effectively proxy the costs associated with recovery of this retrofit investment by the potential end-of-2022 lease termination date (approximately 3-years). In short, on a cumulative present worth basis, there was only a very minor difference in the overall life-cycle costs of the 2019 Rockport Unit 2 SCR Project if all such investment costs were recovered over the shorter 3-year (versus 10-year) period. In fact, analogous to the typical favorable 'present value' economics of a 15-year versus 30-year home mortgage, the full life-cycle economics of the Rockport Unit 2 SCR Project (under Option #1B) would be slightly *improved* by $28 million if recovered over such a shorter (3-year) timeframe. Therefore, any such potential for accelerated Rockport Unit 2 SCR retrofit cost recovery recognition would not have any significant impact on the *long-term* modeled option results to be discussed.

**Q. UNDER "OPTION #1A" YOU INDICATE THE LONG-TERM UNIT DISPOSITION EVALUATION PROCESS UNDERTAKEN HAS ASSUMED THE *FUTURE* RETROFIT OF DFGD TECHNOLOGY ON ROCKPORT UNITS 1 AND 2, AS WELL AS ADDITIONAL FUTURE ENVIRONMENTAL INVESTMENTS. DOES THE USE OF THIS ASSUMPTION MEAN THAT I&M HAS COMMITTED TO SUCH ADDITIONAL ROCKPORT INVESTMENT BEYOND THE ROCKPORT UNIT 2 SCR PROJECT?**

A. No it does not. It simply offers—for current long-term modeling purposes only—a *potential* unit disposition line-of-sight. Under no circumstance does this option constitute a formal plan or recommendation by the Company for either Rockport unit beyond the nearer-term, Rockport Unit 2 SCR Project. Rather, it merely identifies the "down-stream" retrofit requirements/terms of the Modified Consent Decree as well as additional U.S. EPA requirements. Such EPA requirements include the final Coal Combustion Residuals ("CCR") rule addressing new and existing CCR landfills and surface impoundments, as well as the final Effluent Limitations Guidelines ("ELG") rule addressing certain wastewater discharges from power plants; each described by Company witness Hendricks.

**Q. WOULD INSTALLATION OF SCR TECHNOLOGY ON ROCKPORT UNIT 2 BE A REASONABLE APPROACH, EVEN IF I&M ULTIMATELY DECIDED NOT TO INSTALL DFGD TECHNOLOGY ON THAT UNIT IN THE FUTURE?**

A. Yes. To reiterate, the modeling approach taken here was to offer a validation of only the nearer-term "Rockport Unit 2 SCR Project" disposition option. However, by virtue of capturing the current cost and performance parameter estimates associated with *all future* potential retrofit investments for Rockport Unit 2 (and, holistically, all future potential retrofit investments for Rockport Unit 1) as described in TABLE 1-Option #1A; the Company is setting forth a "full picture"—from a long-term economic perspective—of a potential *operate Rockport Plant* disposition plan. This modeling exercise would be formally repeated at some point prior to I&M's commitment to launch into the next phase of this potential long-term disposition (retrofit) plan for the respective Rockport Unit 1 and Unit 2, DFGD projects.

**Q. ADDITIONALLY, THE OPTIONS IDENTIFIED IN TABLE 1 SUGGEST THAT ROCKPORT UNIT 1 WOULD BE THE EARLIER OF THE UNIT RETROFITS FOR DFGD TECHNOLOGY IN THE NEXT DECADE. IS THAT NECESSARILY THE CASE?**

A. No it is not. In fact, the Modified Consent Decree simply identifies that one Rockport unit would "Retrofit, Retire, Re-power or Refuel" by December 31, 2025; and the other by December 31, 2028. It is not specific as to the ultimate unit order. Again, merely for purposes of this modeling exercise it was assumed that Unit 1 would be retrofitted with DFGD by the earlier date. It does not represent a commitment on the part of the Company.

**Q. WHY WERE THE "(COAL-TO-GAS) REFUEL" AND "(CC) REPOWER" OPTIONS CITED IN THE MODIFIED CONSENT DECREE NOT MODELED AS OUT-YEAR ALTERNATIVES?**

A. These options were not modeled as out-year alternatives largely due to the fact that, as addressed in the testimony of Company witness Pifer, the future retrofitting of the Rockport units with DFGD would be a more practical and reasonable option—based largely on known engineering and design factors—versus either re-fueling either of these steam units to burn natural gas, or undertaking a major repowering of the units as natural gas CC facilities. That said, any formal assessment of Rockport disposition options to be performed in the future could more fully examine those additional alternatives.

**Q. WHAT ARE SOME OF THE OTHER UNDERLYING ASSUMPTIONS FOR I&M'S GENERATING FLEET?**

A. The following "base" assumptions were utilized for I&M's Rockport Unit 1, Tanners Creek, D.C. Cook Nuclear, as well as hydro and wind units in <u>each</u> of the alternative options applicable to the Rockport Unit 2 disposition analyses listed in TABLE 1:

- Rockport Unit 1 was assumed to be retrofitted with SCR by December 31, 2017, as planned (and authorized in Cause No. 44523), and DFGD technology by December 31, 2025.
- Tanners Creek Units 1-4 were retired on June 1, 2015 commensurate with I&M's compliance plan to meet the

requirements of EPA's Mercury and Air Toxics Standards ("MATS") rule.

- Continued operation of D.C. Cook Units 1 and 2 through at least the mid-to-late 2030's.[2]
- Continued operation of all pre-existing hydro and wind resources; the latter including a new 200 megawatt (MW) wind purchase agreement effective in 2015.
- Assume the 2016 in-service of the I&M solar pilot projects for approximately 15 MW (total) of solar resources.

Again, this is not a definitive commitment to pursue the installation of a Rockport Unit 1 (or Rockport Unit 2) DFGD. Rather, it simply serves as a going-in basis for the long-term modeling process for the "holistic" I&M resource optimization/disposition analysis. Any consideration of potential DFGD retrofits would be made under a separate, future proceeding.

**Q. LIKEWISE WHAT WERE THE UNDERLYING ASSUMPTIONS ESTABLISHED FOR THE ROCKPORT UNIT 2 LEASE RENEWAL THAT WOULD BE APPLICABLE TO OPTION #1A?**

A. As determined by I&M's management team, for purposes of establishing the economic evaluations for Option #1A, it was assumed that the respective I&M and AEG 50 percent leased shares of Rockport Unit 2 would continue beyond the potential 2022 lease termination date [redacted]

[2] This assumption is in-keeping with the D.C. Cook units' current 20-year Operating License Renewal through 2034 (Unit 1) and 2037 (Unit 2). However, no determination has been made by the Company to potentially pursue an <u>additional</u> license renewal beyond these dates.

[redacted]. As such—and as with many of the other long-term assumptions tied to "Option #1A"—it does not represent the Company's potential negotiating position regarding such lease renewal payments. Rather, it represents a reasonable modeling estimate for purposes of understanding the potential future cost implications for that option.

## V. CONSISTENCY WITH I&M'S 2015 IRP

**Q. ARE THE ROCKPORT UNIT 2 DISPOSITION OPTIONS DESCRIBED IN TABLE 1 CONSISTENT WITH I&M'S RECENTLY-FILED IRP?**

A. Yes. As identified in TABLE 2 below, all three of the options identified on TABLE 1 are essentially the same as several of the "case" views found in the 2015 IRP:

**TABLE 2**

| Rockport U2 CPCN Filing 'Option' | *corresponds directly with...* | I&M 2015 IRP Submittal 'Case' | *Description* |
|---|---|---|---|
| Option #1A | ⟺ | "Steady State" | *BOTH assume RU2 is fully-retrofitted (SCR & DFGD) and operated thru useful life* |
| Option #1B | ⟺ | "Fleet Modification" | *BOTH assume RU2 is retrofitted w/ SCR (only) then returned to Lessor @ 12/2022* |
| Option #2 | ⟺ | "Fleet Modification w/ No RU2 SCR" | *BOTH assume RU2 is NOT retrofitted w/ SCR then returned to Lessor @ 12/2019* |

[redacted]

**Q. ARE THE COMPARATIVE RESULTS TO BE DISCUSSED IN THIS DIRECT TESTIMONY CONSISTENT WITH THE RESULTS SET FORTH IN I&M'S 2015 IRP?**

A. Yes. As I will describe in further detail later, the relative results are very consistent with the "case-to-case" results offered in the IRP. While they do not much exactly match, those differences are minor and are explainable.

## VI. CAPACITY NEED

**Q. DOES I&M HAVE A CAPACITY NEED THAT WOULD BE INFLUENCED BY THIS ROCKPORT UNIT 2 DISPOSITION DECISION?**

A. Yes. First, as explained in greater detail in Attachment SCW-1, I&M has an obligation to maintain a *minimum* PJM Installed Reserve Margin ("IRM") of 16.5 percent.[4] This IRM represents an obligation under PJM's capacity market construct—known as the Reliability Pricing Model ("RPM")—to ensure adequate future capacity resources are available to cover the Company's projected summer peak demand, as well as a reserve margin, needed to reasonably ensure reliability in the event of unforeseen supply interruptions and/or high peak demand events. As summarized on Attachment SCW-1, Table 1-4, *inclusive* of Rockport Unit 2, the projected I&M IRM for the next PJM RPM planning year, 2019/20,[5] is estimated at 20.56 percent. This IRM

---

[4] Beginning with the current 2019/20 (June 1 through May 31) PJM RPM planning year; and assumed to remain constant in all future RPM planning years. In prior (2016/7 through 2018/19) planning/delivery years this requirement was slightly lower at 16.4 percent.

[5] As also discussed in Attachment SCW-1, I&M (as well as affiliates Appalachian Power Company and Kentucky Power Company) have continued to opt-out of the RPM "capacity auction" process by participating in the Fixed Resource Requirement ("FRR") "self-planning" construct afforded under the RPM. Under the RPM framework that establishes a 3-year forward commitment, this FRR obligation has now been established through at least the 2019/20 RPM planning year.

level would result in a capacity "length"—*i.e.*, capacity levels above the minimum 16.5 percent PJM criterion—of a reasonable 159 MW.

Therefore, any unit disposition decision that would implement an alternative of retiring I&M's 1,105 MW ownership and purchase entitlement share of Rockport Unit 2 [6] would result in an immediate and significant need to replace nearly all of that capacity to ensure the achievement of this PJM IRM criterion. This explains why the "Option #1B" and "Option #2" alternatives previously identified in TABLE 1 would necessitate a near-concurrent replacement of the unit with significant capacity replacements.

**Q. IS THE UNDERLYING I&M LOAD AND PEAK DEMAND FORECAST AND ULTIMATE CAPACITY "NEED" CONSIDERED AS PART OF THIS ROCKPORT UNIT 2 DISPOSITION ANALYSIS ALSO CONSISTENT WITH THAT WHICH WAS REPRESENTED IN THE COMPANY'S NOVEMBER, 2015 IRP?**

A. Yes. There were no changes to the long-term load and peak demand forecast, as well as assumptions around available capacity resources, from the forecast utilized in I&M's 2015 IRP. I am aware that I&M was recently notified that some contracts for wholesale supply may end in 2020. While the load associated with these contracts was included in the long-term load forecast, a potential change in the disposition of the load contracts, should they leave the system, would not alter the conclusion in this testimony. The potential loss of this approximately 300 MW of internal load would not diminish the Company's future need for Rockport Unit 2 or, alternatively,

[6] 650 MW (50%) I&M ownership share of the 1300-MW unit; plus I&M's 455 MW (70%) purchase entitlement from affiliate AEG's 50% ownership share of the unit.

some level of replacement resources that reasonably approaches that unit's level of capacity should it be returned to the Lessor.

## VII. ECONOMIC MODELING PROCESS

**Q. HOW WERE THE ROCKPORT UNIT 2 DISPOSITION ALTERNATIVES ANALYZED?**

A. The Company utilized a proprietary long-term resource optimization tool known as Plexos® (also referred to as "Plexos® LT Plan") to perform this evaluation. The economic evaluations were performed from the perspective of a "stand-alone" I&M. This means there were no assumed capacity and energy costs or credits flowing to/from affiliate AEP operating companies by virtue of the fact that the long-standing AEP Interconnection Agreement ("AEP Pool") has now been terminated and replaced with the FERC-authorized Power Coordination Agreement ("PCA") effective January 1, 2014. Under the terms of the PCA, I&M, as well as the other AEP-affiliate operating company participants in the PCA, "...will be individually responsible for its own capacity planning."[7]

Further, these resource optimization evaluations were performed over an extended (30-year) modeled period (2016 through 2045) in the Plexos® tool so as to roughly emulate the potential economic life-cycle of the respective asset alternatives offered in TABLE 1; as well as in recognition of the various future impacts on I&M's overall resource planning needs. As will be described in more detail, the alternative-specific 'Net Utility Costs' were

[7] Article 7.1 of the Power Coordination Agreement (FERC Docket No. ER13-235-000, approved on December 23, 2013).

then discounted to current, "(January) 2016" dollars and, as such, reflected on a cumulative present worth ("CPW") basis.

It is also critical to understand that the framework for these evaluations was focused not on the *absolute* CPW results for I&M, but rather the *comparative* view of the alternative options' results. In other words, the objective of this exercise was to identify the relative least-cost alternative among the three primary options identified in TABLE 1. With that, the results from Plexos® offer a view of these relative optimization economics over that full, 30-year planning horizon and thereby do not in any way constitute an isolated, single "test-year" cost-of-service view.

**Q. PLEASE DESCRIBE THE PLEXOS® LONG-TERM MODELING APPLICATION.**

A. Plexos® is a proprietary software tool under license to AEPSC from Energy Exemplar LLC, a power and gas industry software and data-services provider. As indicated, the Plexos® LT Plan version of the application is a long-term resource optimization model that offers multiple objective functions, including determination of alternative planning solutions that offer the lowest utility cost. In this case, it is intended to determine a proxy for the lowest "G(eneration)" (net) cost-of-service.[8] The model uses linear programing ("LP") optimization techniques to find the optimal portfolio of future capacity and energy resources, including demand-side additions, that serve to minimize the CPW of a planning entity's production-related fixed and variable costs over a long-

[8] It is important to re-emphasize that Plexos® does not produce, nor are these (relative) long-term modeling results intended to represent, a traditional "cost-of-service" view; recognizing that the latter process focuses on a single 'absolute'—versus 'comparative'—view of costs and is also limited to a single 'test-year'—as opposed to a 30-year proforma—view.

term planning horizon. The model performs this optimization while also recognizing user-input constraints such as requisite PJM reserve margin requirements, as well as I&M fleet-wide or unit-specific stack emission (e.g. $SO_2$ and $NO_X$) limitations.

This latter ability is important given that the Modified Consent Decree also places a Rockport (total) station-specific "cap" on $SO_2$ emissions of 28,000 tons per year in 2016-2017; 26,000 tons per year in 2018-2019; 22,000 tons per year in 2020-2025; 18,000 tons per year in 2026-2028; and 10,000 tons per year in 2029 and thereafter.[9] These station-specific $SO_2$ requirements are over-and-above the pre-existing AEP performance thresholds around $SO_2$ and $NO_X$ emissions as set forth in the original NSR Consent Decree. As further described by Company witness Hendricks, the retrofit of SCR on Rockport Unit 2 will contribute to the attainment of that Consent Decree requirement.

**Q. HAS THE PLEXOS® APPLICATION BEEN UTILIZED BY THE COMPANY IN MATTERS BEFORE THIS COMMISSION?**

A. Yes. Plexos® was utilized as the applicable modeling tool for determining the relative economics of the Rockport Unit 1 SCR Project in Cause No. 44523. It was also utilized as the basis for all proforma analyses in I&M's most recent IRP submitted on November 2, 2015. Specifically, it served as the basis for the establishment of the resource planning included under Section 8-

[9] The last threshold year (2029) representing the first year in which <u>both</u> Rockport units would be potentially retrofitted with DFGD technology under the Modified Consent Decree.

"Selection of the Resource Plan"—as required under 170 IAC 4-7-8.[10] Additionally, Plexos® was utilized as part of the Company's most recent biannual Fuel Adjustment Clause ("FAC") filings.[11] It was also utilized as part of I&M's most recent Environmental Compliance Cost Rider ("ECCR") filings.[12] Likewise, Plexos® was utilized to establish I&M's most recent Power Supply Cost Recovery plan for its Michigan retail jurisdiction.[13] Further, Plexos® has recently been utilized by other AEP operating companies to support both long-term resource planning options as well as shorter-term fuel factor applications before Commissions in the states of Arkansas, Kentucky, Oklahoma, Texas, Virginia, and West Virginia.

**Q. YOUR TESTIMONY DESCRIBES THAT THE PLEXOS® (LT PLAN) MODELING CREATES A PROXY FOR LONG-TERM NET UTILITY "G(ENERATION)" COSTS. WHAT ARE THE FUNDAMENTAL MODELING PROCESSES AND OUTPUTS THAT CREATE THESE RESULTS?**

A. First, the Plexos® model seeks to emulate the PJM energy construct in which all available generation is offered into, and is compensated by, the PJM energy market; while all Load Serving Entities, such as I&M, are price-takers from that market. Both of these time-based value-sets are predicated on the future, fundamentals-based price of energy which will be described later in this testimony. As a vertically-integrated utility, the subsequent 'netting' of those (PJM) "(Generation) Market Revenues" and "Load Costs" profiles are

[10] *See* Section 5 of that submittal for a description of how Plexos® LT Plan was utilized in I&M's 2015 IRP.
[11] *See* IURC Cause Nos. 38702-FAC73, 38702-FAC74 and 38702-FAC75 and 38702-FAC76.
[12] *See* IURC Cause Nos. 43992-ECCR 4 and 43992-ECCR 5.
[13] *See* MPSC Case No. U-17919

then appended to the anticipated production cost of I&M's native generation, to create a full picture of I&M's projected future net utility (generation) costs. The model determines such generation-related costs as follows:

*Cost of Generation…*

Variable Costs associated with I&M generating units' ability to offer—and ultimately dispatch—into the (PJM) energy market. Such attendant variable costs including:

- Fuel;
- Start-up oil;
- Consumables such as sodium bicarbonate, activated carbon, anhydrous ammonia, and lime;
- Variable O&M; and
- Market replacement cost of emission allowances and/or carbon 'tax'

*Plus*: Variable Costs of Energy Purchases

*Plus*: Fixed Costs of Capital Additions *; *i.e*, Investment Carrying Charges (based on I&M's weighted cost of capital)

*Plus*: Fixed O&M of Capacity Additions

*Plus*: Fixed Cost of Capacity Purchases

*Plus*: Program Costs of (Incremental) Demand-Side Management (DSM) options

= **Total Generation Costs**

* Note: Any on-going 'return-on' and 'return-of' (depreciation/amortization) capital costs associated with pre-existing generation plant-in-service and other balance sheet assets/obligations are ignored, as such attendant costs would be assumed to be *consistent across all unit disposition options evaluated.*

To further summarize, the Plexos® model simultaneously determines the energy-related "Cost of Load" based on projected PJM "scaled" (e.g. hourly on-peak and off-peak) market energy prices applied to I&M's forecasted native load obligation—and underlying load shape. The model output then performs a concurrent "netting" of: a) I&M's Load cost; and b) the production *revenue* made into the forecasted (PJM) energy market from the *generation* shape profiles modeled for each I&M generation resource. When then further coupled with the "Cost of Generation" previously defined, the ultimate 'net' output represents a proxy for I&M's net load/production-related generation costs. The final component output from the modeling process would be the monetization of any I&M <u>capacity</u> length (long *or* short position)—vis-a-vis PJM's minimum reserve margin requirements—based on projected PJM capacity market values. The *final* result is the establishment of I&M's "Net Utility (Generation) Costs" summarized as follows:

| | |
|---|---|
| | (PJM) Load Cost |
| *Plus:* | Cost of Generation *(as above)* |
| *Less:* | (PJM) Energy Market Revenue |
| = | Net Load/Production-related Generation Costs |
| *Less:* | (PJM) Capacity Market Revenue/<Cost> |
| = | **Net Utility (Generation) Costs** |

These life cycle costs through the 2045 modeled optimization period, along with applicable end-effects[14], are then "present-valued" using a proxy of the estimated I&M-weighted average cost of capital, to create a CPW of Net Utility (Generation) Costs.

**Q. SPECIFICALLY, HOW DID THE PLEXOS® MODEL PERFORM THE ROCKPORT UNIT 2 DISPOSITION ANALYSES SUMMARIZED ON TABLE 1?**

A. For "Option #1A", the model incorporated the Rockport Unit 2 SCR Project alternative—and timing thereof—as described earlier in TABLE 1. Specifically, Rockport Unit 2 was assumed to be "fully-retrofitted" in the future, first with DSI and associated equipment (for MATS compliance), then SCR

[14] Recognizing the varying life cycle periods among alternatives evaluated, an "end-effects" determination was made that is representative of the present value of any on-going cost streams beyond the model's 2045 optimization period.

technology by December 31, 2019; and finally with subsequent anticipated environmental-related retrofits thereafter—including DFGD technology—by December 31, 2028. The Rockport Lease was assumed to be renewed for Unit 2, while the remaining I&M generating units were assumed to follow the "base" disposition path assumptions as previously discussed.

For "Option #1B", the model assumed Rockport Unit 2 would be returned to the unit's Lessors at the lease termination date of December, 2022, with the installation of the SCR in 2019—consistent with Option #1A—but, naturally then, *without* the installation of a DFGD in 2028. Upon the unit's assumed return to the Lessors, the model further assumed that nearly all of the significant displaced Rockport Unit 2 capacity and energy would require concurrent replacement resources.

Finally, for "Option" #2, the model assumed Rockport Unit 2 would be returned early to the Lessors—by December 2019—*without* the installation of an SCR in 2019, and a DFGD in 2028. This modeled view also incorporated the required concurrent resource replacement upon the unit's return to the Lessors.

For each view (Options #1B and #2) requiring nearer-term replacement resources, the model was given the ability to select the specific type of capacity resource required to replace Rockport Unit 2 by way of Plexos®-LT Plan's resource optimization logic. In that regard, given the assumption of the impracticality of a coal solution due to proposed $CO_2$ emissions regulations applicable to new fossil-fired generating resources, a new coal-fired generating build was not considered.[15] Likewise, given the financial impracticability of new nuclear capacity with estimates costs exceeding $6,000/kW, a new nuclear unit was also not considered.[16] With that, the model had the ability to choose between some combination of natural-gas fired combined cycle ("CC"), combustion turbine ("CT"), aeroderivative ("AD"), combined heat and power ("CHP"), as well as renewable and incremental demand-side management ("DSM") resources; all consistent with the resource replacement options utilized in the 2015 IRP.[17]

From there, the model was set up with the necessary input parameters, such as capital cost to retrofit or to replace with alternative resources, the attendant fuel cost and generator performance parameter data, modifications to variable and fixed O&M, etc. Based on these inputs, beginning in the year 2020—the initial full year of Rockport Unit 2 being retrofitted with SCR—the model was then capable of recognizing any relative change in the overall I&M generation profile for each of the three Rockport Unit 2 disposition options identified in TABLE 1. Additionally, the capacity resource planning aspect of the tool recognized the megawatt contribution of these alternative solutions when determining capacity needs for I&M *beyond*

---

[15] New EPA regulations pertaining to Section "111(b)" of the Clean Air Act require new coal-fired generating facilities to emit no more than 1,400 lb/Mwh of $CO_2$; levels essentially unachievable without some form of costly carbon capture and sequestration technology.

[16] For example, a nuclear unit @ 1,100 MW –roughly comparable to the size of either of I&M's D.C. Cook nuclear units; or the size of I&M's share of Rockport 2 being replaced— would cost $6.6 Billion ($6,000/kW x 1,100 MW x 1,000 kW/MW = $6,600,000,000).

[17] Specifically, additional DSM over-and-above the levels embedded in the Company's load & peak demand forecast (as summarized on Attachment SCW-1, Table 1-3); as well as additional I&M renewable resources over-and-above those currently identified (or footnoted) on Attachment SCW-1, Table 1-2.

2020, as it modeled throughout the long-term optimization planning horizon (*i.e.*, through 2045).

**Q. PLEASE IDENTIFY SOME OF THE INPUT PARAMETERS FOR THESE ROCKPORT UNIT 2 DISPOSITION ANALYSES?**

A. Two of the major underpinnings in this process are long-term forecasts of I&M's energy requirements and peak demand, as well as the price of various generation-related commodities, including energy, capacity, coal, natural gas, and $CO_2$/carbon. Both forecasts were created internally within AEPSC. The load forecast, including I&M load and peak demand summaries discussed in Attachment SCW-1, represents the projection created by the AEP Economic Forecasting organization in June 2015 that led up to, and was utilized in, the 2015 IRP. Attachment SCW-2 offers the long-term commodity pricing forecast established by the AEP Fundamental Analysis group in that same June/July 2015 timeframe. These respective organizations have had years of experience forecasting I&M and AEP system-wide demand/energy requirements and fundamental pricing for both internal operational and regulatory purposes.

Other critical input parameters include the installed cost of the required Rockport Unit 2 SCR Project, the cost to build/buy replacement capacity (e.g. CC, CTs, ADs, CHP, renewable [wind, solar], or incremental DSM), as well as the attendant on-going operating costs and performance parameters associated with those unique options, where applicable. Much of this information is summarized on Attachment SCW-3. The critical build-cost data was largely provided by Company witness Pifer and the AEP Generation organization of which he is a part.

**Q. PLEASE PROVIDE AN ADDITIONAL OVERVIEW OF THE "RETURN AND REPLACE" OPTIONS (OPTION #1B AND OPTION #2).**

A. The Plexos® modeling required to reasonably proxy this option as it pertains to the installation of nearer-term baseload/intermediate duty-cycle capability was based on resource "blocks" equivalent to *one-half* of a Mitsubishi 501 GAC 2x2x1 combustion turbine/heat recovery steam generator (HRSG)/steam turbine design[18] natural gas CC that would have a nominal capability of approximately 780 MWn[19]. This was done as an input process to the Plexos® modeling so as to allow for reasonably equivalent "block-sizes" amongst the available resource options. Therefore, each CC equivalent block-size the model could select was equal to 390 MWn. This type/construct of CC was screened as being the 'best-in-class' from multiple potential CC designs.

The chosen proxies for potential peaking duty-cycle capability were based on both a simple-cycle General Electric ("GE") 2x '7FA' (large-frame) *and* GE 2x '7EA.03' (small frame) natural gas CT block-sizes the model could select having a nominal capability of approximately 431 and 189 MWn, respectively.[20] Additionally, the model could choose 2x GE LM6000 AD units

---

[18] This represents two natural gas combustion turbines in combination with two HRSGs and a single steam turbine.

[19] This Mitsubishi design CC would provide, via evaporator cooling, additional unit generating capability—albeit at some thermal efficiency/heat rate penalty—to 870 MW.

[20] Each GE 7FA turbine is nominally rated @ 215.5 megawatts ("MWn"). Each GE 7EA.03 turbine is nominally rated @ 89.5 MWn. A minimum GE 7FA and 7EA.03 SC block size was assumed to be 2 turbines; or ~431 MWn and 189 MWn, respectively.

having a nominal capability of approximately 87 MWn[21] per block. Lastly, it could also select scaled CHP-cogeneration units[22]. The GE SC-CTs, GE-ADs as well as CHP generating resources were all screened as the best-in-class from multiple potential "peaking" duty-cycle resource options.

**Q. WHAT ESTIMATED COSTS FOR OPTION #1A, OPTION #1B, AND OPTION #2 WERE UTILIZED IN THE ECONOMIC EVALUATIONS?**

A. The following **TABLE 3** offers a summary of the installed cost estimates modeled:

[21] Each GE LM6000 AD turbine is nominally rate @ approximately 43.5 MWn, also with a minimum block size of 2 turbines; or ~87MWn.

[22] The CHP-cogeneration tranche size is based on a reduced-scaled LM6000 turbine, coupled with a full steam host, offering a generation output of approximately 15 MWn.

# TABLE 3

**Estimated Rockport Unit 2 Disposition Alternatives**
**Major Capital Expenditures** (excl. AFUDC)
Utilized in Plexos® Modeling
<u>In Addition to</u> Wind, Solar and (Incremental) DSM

| | | | | (a) | (b) | (c) | (d) | (e) |
|---|---|---|---|---|---|---|---|---|
| | | | | Direct (EPC) & Indirect Costs | | I&M/AEG Prod. Capital Overhead | TOTAL COST *(Excluding AFUDC)* | |
| (1) | | *Unit Capacity* | | Millions | $/kW Installed | Millions | Millions | $/kW Installed |
| (2) | | *MW* | | *('As-Spent' $)* | *(2015 $)* | *('As-Spent' $)* | *('As-Spent' $)* | *(2015 $)* |
| (3) | Option #1A: | | | | | | | |
| (4) | (Unit 2 RETROFIT Option) | | | | | | | |
| (5) | TOTAL Project Costs | | | | | | | |
| (6) | **Rockport U2 SCR (12/2019 in-Svc)** (Option #1A and Option #1B) | 1,336 | (A) | **257** | **$177** | **17** | **274** | **$189** |
| (7) | *Plus: Potential Subsequent Major U1 & U2 Investments included in Modeling:* | | | | | | | |
| (8) | *RK U1 DFGD & Assoc. (12/2025 In-Svc) (ALL Options)* | *1,333* | (B) | *1,217* | *$729* | *82* | *1,299* | *$778* |
| (9) | *RK U2 DFGD & Assoc. (12/2028 In-Svc) (Option #1A only)* | *1,318* | (B) | *1,306* | *$734* | *88* | *1,394* | *$784* |
| (10) | *RK U1 & U2 "CCR/ELG"-related,* | | | | | | | |
| (11) | *Total Plant (thru 2021) (ALL Options)* | *2,687* | (A) | *179* | *$60* | *12* | *191* | *$64* |
| (12) | *TOTAL ALL Major Rockport Environmental Projects (U1&2) (Opt #1A onl* | *2,651* | (B) | *2,958* | *$882* | *200* | *3,158* | *$941* |
| (13) | ***I&M Ownership Share @ 50%*** | | | | | | | |
| (14) | **Rockport U2 SCR (12/2019 in-Svc)** (Option #1A and Option #1B) | *668* | | **128** | **$177** | **9** | **137** | **$189** |
| (15) | ***I&M 70% Purchased Power Portion of AEG's 50% Ownership Share (C)*** | | | | | | | |
| (16) | **Rockport U2 SCR (12/2019 in-Svc)** (Option #1A and Option #1B) | *468* | | **90** | **$177** | **6** | **96** | **$189** |
| (17) | | *Unit Capacity* | | Millions | $/kW Installed | Millions | Millions | $/kW Installed |
| (18) | | *MW* | | *('As-Spent' $)* | *(2015 $)* | *('As-Spent' $)* | *('As-Spent' $)* | *(2015 $)* |
| (19) | Option #2 (and Option #1B): | | | | | | | |
| (20) | (Unit 2 CAPACITY REPLACEMENT Options) (D) | | | | | | | |
| (21) | **New-Build CC**... 1/2023 In-Svc (Option #1B) | *1x390MWn (435 w/evp clg) "block"* | | 547 | $1,087 | 37 | 584 | $1,160 |
| (22) | " " " ... 1/2020 In-Svc (Option #2) | " | | 507 | $1,087 | 34 | 541 | $1,160 |
| | *AND (IN COMBINATION WITH) / OR ...* | | | | | | | |
| (23) | **(2)X New-Build CT (7FA)**... 1/2023 In-Svc (Option #1B) | *2x215.5 = 431 per block* | | 384 | $753 | 26 | 410 | $804 |
| (24) | " " " " ... 1/2020 In-Svc (Option #2) | " | | 356 | $753 | 24 | 380 | $804 |
| | *OR* | | | | | | | |
| (25) | **(2)X New-Build CT (7EA.03)**... 1/2023 In-Svc (Option #1B) | *2x89.5 = 179 per block* | | 212 | $1,001 | 14 | 227 | $1,068 |
| (26) | " " " " ... 1/2020 In-Svc (Option #2) | " | | 197 | $1,001 | 13 | 210 | $1,068 |
| | *OR* | | | | | | | |
| (27) | **(2)X New-Build AD (LM6000)**... 1/2023 In-Svc (Option #1B) | *2x43.5 = 87 per block* | | 114 | $1,107 | 8 | 122 | $1,182 |
| (28) | " " " " ... 1/2020 In-Svc (Option #2) | " | | 106 | $1,107 | 7 | 113 | $1,182 |
| | *OR* | | | | | | | |
| (29) | **CHP-Cogen(LM6000 w/stm hst)**... 1/2023 In-Svc(Option #1B) | *15* | (E | 32 | $1,773 | 2 | 34 | $1,893 |
| (30) | " " " " ... 1/2020 In-Svc (Option #2) | " | | 29 | $1,773 | 2 | 31 | $1,893 |

(A) Rockport U1 & U2 capacity rating post-planned LP Turbine (36 MW each) uprates (2017 & 2019)
(B) Rockport U1 & U2 capacity rating post-DFGD retrofits (<18 MW> each) derates (2025 & 2028)
(C) I&M would ALSO incur its 70% share of fixed costs associated with <u>AEG's</u> like-50% share of the project (or, 35% of the 'Total Project') under the terms of the affiliate AEP Generating Company (AEG) Unit Power Agreement with I&M.
(D) AEP Projects cost estimates used for modeling purposes.
(E) Assumes a full-utilization steam host (thermal efficiency @ ~4,858 Heat Rate)

The costs reflect the 50 percent ($137 million) I&M ownership share of the capital expenditure associated with the Option #1A and #1B Rockport Unit 2 SCR Project. I&M-affiliate AEG would be responsible for the other 50 percent share of the required capital expenditure. In recognition of this, however, these I&M-Rockport Unit 2 disposition analyses *also* considered 70 percent of the costs of the AEG ownership portion of this retrofit solution by virtue of I&M's obligation under the AEG UPA. Stated another way, the Option #1A and #1B analyses effectively reflected 85 percent (1,105 MW) of the capacity (and energy output), as well as the respective attendant costs, associated with the approximate 1,300 MW Rockport Unit 2 SCR Project estimate.[23]

Note also that these costs are exclusive of allowance for funds used during construction ("AFUDC"). As it pertains to the Option #1A and #1B Rockport Unit 2 SCR Project estimate, the total project cost inclusive of production capital overheads as well as AFUDC was modeled at approximately $295 million (with I&M's 50% ownership share being approximately $147 million). Conservatively, this calculated AFUDC proxy of nearly $21 million (I&M's ownership share being approximately $10 million) was incorporated for comparative modeling purposes only and is, obviously, before consideration of any potential construction work in progress ("CWIP") recovery treatment as discussed in Company witness Williamson's testimony

[23] Represents I&M's 50% ownership share, plus, 70% of AEG's 50% ownership share, or 85%.

that would serve to eliminate all or a portion of any such project-related AFUDC.[24]

**Q. EARLIER YOU DISCUSSED "DOWN-STREAM" COSTS ASSOCIATED WITH ENVIRONMENTAL INVESTMENTS BEYOND THE CURRENT ROCKPORT UNIT 2 SCR PROJECT. PLEASE BRIEFLY DESCRIBE THE OPTION #1A TOTAL UNIT 2 COST PROJECTIONS INCORPORATED INTO YOUR MODELING.**

A. As summarized on TABLE 3, the Plexos® modeling for Option #1A incorporated approximately $1,347 million of additional estimated I&M capital costs for various future Rockport Unit 2 projects <u>beyond</u> this Unit 2 SCR Project. Specifically, this figure represents I&M's 85 percent ownership *and* (AEG) purchased power share of the combined investment in future Unit 2 DFGD and associated equipment (total $1,394 million), and "CCR/ELG-related" ($191 million, total plant) capital costs identified on TABLE 3.[25]

**Q. HOW WERE ROCKPORT UNIT 2 CAPACITY *REPLACEMENT* ALTERNATIVES CONSIDERED IN EITHER OPTION #1B OR OPTION #2?**

A. The Plexos® modeling was based on the assumption that any and all incremental capacity and energy requirements to achieve I&M's projected native peak demand and load requirements, in recognition of a Rockport Unit 2 return to Lessors by December 2022 (Option #1B), or by December 31, 2019 (Option #2), would be wholly met via CC, CT, AD, CHP, renewable and

[24] $295 million total (100%) project cost - $274 million total cost (including production capital overhead, but excluding AFUDC – see TABLE 3)
[25] ($1,394 million + $191 million) x 85% = $1,347 million (including capital overheads, excluding AFUDC).

incremental DSM replacement capacity and energy contemporaneously with those respective dates.

**Q. IN DEVELOPING THE COMPANY'S FUTURE RESOURCE ALTERNATIVES AS PART OF OPTIONS #1B AND #2, DID THE COMPANY EVALUATE DEMAND-SIDE/ENERGY EFFICIENCY AND DEMAND RESPONSE RESOURCES?**

A. Yes. As described and detailed in Attachment SCW-1, Section H, DSM in the form of Energy Efficiency (EE) and Demand Response (DR) initiatives have been incorporated into the Company's resource planning process, initially, as part of its underlying load forecast. These forecasted levels of EE reductions incorporated into all of I&M's long-term resource modeling are significant. Note on Table 1-3 of Attachment SCW-1, that the Company is projected to realize permanent peak demand reductions from EE alone of 64 MW over the balance of this decade. Additionally, the Company is expected to add further peak demand reductions via 'demand response' activity of 298 MW. With that, the Company's *total* demand-side peak reduction capability is already projected to be 363 MW by 2020. This amount is equal to approximately 9.8 percent of I&M's forecasted retail peak demand.[26] Given the more limited ability of DSM to add extremely large tranches of resources to I&M's overall portfolio—over-and-above what is already contemplated in the underlying load and peak demand forecast—as a practical matter such amounts must be considered minimal in the context of the approximate 1,100 MW of I&M's share of Rockport Unit 2 capacity that would be required to be replaced.

[26] Based on projected 2020 I&M (retail only) peak demand *before* DSM of 3,702 MW.

That said—consistent with the underlying modeling for its 2015 IRP--I&M's Plexos® long-term resource optimization modeling did consider such *incremental* contributions of EE resources as part of this Rockport Unit 2 evaluation process. The model was given the ability to select from eight (8) potential incremental DSM-EE measure "bundles" including: Residential Heating/Cooling; Residential Thermal Shell; Residential Lighting; Residential Water Heating; Residential Appliances; Commercial Heating/Cooling; Commercial Lighting; and Commercial Office Equipment.

**Q. COULD ADDITIONAL RENEWABLE RESOURCES—OVER-AND-ABOVE I&M'S 450 MW OF WIND RESOURCES AND 15 MW OF SOLAR RESOURCES—BE CONSIDERED A VIABLE DISPOSITION ALTERNATIVE FOR ROCKPORT UNIT 2 REPLACEMENT CAPACITY IN OPTIONS #1B AND #2?**

A. Yes, but as with incremental DSM, only to a limited degree. Given the intermittent nature of, for instance, wind resources, only a small percentage of the "nameplate" capacity rating of wind is currently being recognized by PJM for reliability/capacity resource adequacy planning purposes. In fact, PJM initially recognizes or "counts" only 13 percent of a wind resource's nameplate (MW) rating for such capacity planning purposes.

Further, as described more fully in Attachment SCW-1, beginning with the 2020/21 PJM Planning Year a new FERC-authorized RPM tariff referred to as the "Capacity Performance" construct will be in full effect. At that point all intermittent resources, including wind, are anticipated to experience a further reduction in the level of capacity resources that may be applied when establishing PJM capacity position/need. For purposes of future capacity resource commitments under that Capacity Performance construct, the Company assumed that the amount of a wind resource's nameplate (capacity) rating that will be applicable would be zero beginning with that 2020/21 PJM-RPM planning period. Therefore, wind resources, which can be a beneficial source of energy by adding diversity to a generating portfolio, cannot serve as a viable *capacity* replacement alternative in this instance. In any event, irrespective of the anticipated new 'Capacity Performance' limitations, even under the *current* (13 percent of nameplate) PJM framework—which is not subject to conjecture—wind resources would be able to contribute only limited capacity resources to meet the reserve margin criterion. For example, to meet even just *one-tenth* of the Company's capacity obligation in lieu of Rockport Unit 2 post-2020, 850 MW (nameplate) of additional wind resources would be required over-and-above the 450 MW of wind resources the Company already currently possesses.[27] Under the emerging *Capacity Performance* approach, wind has been assumed not to "count" for purposes of I&M achieving its future capacity resource requirement.

The implication is similar for solar resources. That is, currently PJM initially counts only 38 percent of a solar resources nameplate MW rating when establishing capacity contribution to meet load/demand and reserve margin obligations. Unlike wind resources, however, for purposes of future resource commitments under that Capacity Performance construct, the

[27] 1,105 MW x 1/10 = 110.5 MW / 0.13 (PJM [nameplate] assumed installed capacity criterion limitation re wind resources) = 850 MW

Company assumed that the amount of a solar resource's nameplate rating that will be applicable for capacity planning purposes would remain at that 38 percent level beginning with that 2020/21 PJM-RPM planning period.[28] So, again, to meet even just *one-tenth* of the Company's capacity obligation in lieu of Rockport Unit 2, over 290 MW (nameplate) of additional solar resources would be required post-2020.[29]

However, to be non-discriminatory as to the overall make-up of the available suite of resources to potentially replace Rockport Unit 2, the Company—as it did with incremental DSM—considered the prospect of renewable resources; namely, wind and large/community-scale solar, as potential capacity (and energy) resource options from which the Plexos® long-term optimization modeling could select over the long-term optimization study period. As with incremental DSM, however, this would recognize that, at best, such (incremental) wind or solar resources would likely be able to contribute only a small fraction of the *capacity* contribution lost by the retirement of Rockport Unit 2.

**Q. ARE THESE WIND AND SOLAR CAPACITY RESOURCE CRITERIA CONSISTENT WITH THOSE UTILIZED IN I&M'S 2015 IRP?**

A. Yes. The 2015 IRP also assumed the 'post-2020' level of wind and solar that could 'count' in the achievement of its PJM minimum reserve margin requirement would be set at 0 percent and 38 percent of nameplate, respectively.

---

[28] This was done in recognition of the fact the load shape of a solar resource is typically more coincident to an overall PJM summer peak condition/hour than that of a wind resource.

[29] 1,105 MW x 1/10 = 110.5 MW / 0.38 (PJM [nameplate] installed capacity criterion limitation re solar resources) = 291 MW

**Q. IS PROJECTED NATURAL GAS PRICING A DRIVER FOR SUCH ANALYTICAL PROCESSES?**

A. Yes, it typically is. In the electric utility industry, the natural gas-fired units often serve as the marginal cost, or "price-setting" units based on their relative higher position in a typical regional dispatch stack (relative to lower variable cost hydro, nuclear and coal-fired units). In PJM, that is most typically the case during "on-peak" hours.[30] Therefore, the price of natural gas will not only determine where gas-fueled units may fall in any regional dispatch stack, it will then largely determine the Locational Marginal Price ("LMP") in which energy may clear in any market-based system such as PJM.

Typically, the higher the natural gas price, the higher gas-fired units—such as even thermally-efficient combined cycle units—would climb in PJM's dispatch stack; and then, depending upon contemporaneous load requirements and constraints, the higher the resulting market-based energy price/LMP might be. Based on that, margins or "spreads" available to more efficient coal-fired units could simultaneously be improved.

Conversely, the lower the gas price, the lower these CC units may fall in PJM's market-based dispatch/supply stack, thereby setting a lower clearing price for a greater number of hours/sub-hours. Under this latter outcome, coal units could potentially be called upon to generate less energy at a lower available spread.

**Q. PLEASE PROVIDE AN OVERVIEW OF THE FORECASTED FUNDAMENTAL COMMODITY PRICING, INCLUDING NATURAL GAS,**

[30] Although the definition varies, typically, on-peak hours represent a 16-hour per-day period M-F, 6AM-10PM, excluding holidays.

**THAT WERE USED IN THE ROCKPORT UNIT 2 DISPOSITION ANALYSES?**

A. As shown in **TABLE 4** below, an array of five (5) unique, long-term commodity pricing scenarios were utilized in the Rockport Unit 2 disposition analyses, consisting of a "base" view; two "price banding" sensitivity views; and two "$CO_2$/carbon" views:

**TABLE 4**

**'BASE' Forecast** ... *reflecting:*

- Recognition of relatively lower fuel price trending due to proliferation of shale gas, increasing natural gas price elasticity; as well as capturing a likely implementation profile of environmental regulation including CSAPR, MATS Rule and potential $CO_2$ mitigation via a ~$15/tonne[31] "carbon tax" (beginning in 2022).

***Commodity Price Banding Scenarios...***

**2.** "Higher Band"... *same as the BASE case except:*
- Bounds the high-end of the BASE case with plausible fuels, emissions and energy pricing—with appropriate feedback for load response—and with such fuel prices varying by approximately a +1.0 standard deviation.

**3.** "Lower Band" ... *same as the BASE case except:*
- Likewise, bounds the low-end of the BASE case with plausible fuel, emissions and energy pricing, with such fuels prices varying by approximately a -1.0 standard deviation.

***$CO_2$ Pricing Scenarios...***

**4.** "No Carbon" Price... *same as the BASE case except:*
- Removes the proxy carbon tax from the suite of commodity pricing; while then adjusting for the correlative effects on other commodities associated with that removal.

**5.** "High Carbon" Price... *same as the BASE case except:*
- Increases the scale of the relative carbon tax by a magnitude of approximately 60% (to ~$25 tonne).

[31] The unit of measure representing a "metric" ton of $CO_2$ equal to 1,000 kilograms or 2,204 pounds and represented in "real" (2014) dollars.

The "BASE" Forecast" view reflects the full suite of long-term projection of commodity prices—inclusive of natural gas prices—established by the AEP Fundamental Analysis group that were used in this analysis. This forecast was internally published in the mid-2015 timeframe. Selected commodity pricing projections from that suite are reflected in Attachment SCW-2. This BASE Forecast view focused significantly on emerging natural gas pricing dynamics and considered evolving information that would support natural gas supply increases tied to the projected emergence of additional, significant levels of domestic shale gas at very competitive extraction costs.

This long-term view also assumes and embeds a "$CO_2$ pricing" impact as a result of potential carbon regulation such as the regulation of $CO_2$ emissions from *existing* fossil-fueled generating sources as recently set forth by the U.S EPA under Section 111(d) of the Clean Air Act via its Clean Power Plan ("CPP"). In conjunction with the final CPP ultimately submitted in August of 2015, the timing of a carbon pricing proxy in these long-term fundamental pricing forecasts was likewise assumed to be the year 2022.[32]

**Q. ARE THE LONG-TERM COMMODITY PRICE FORECASTS USED IN THIS ROCKPORT UNIT 2 SCR PROJECT ANALYSIS—SUMMARIZED ON TABLE 4—CONSISTENT WITH THE PRICING FORECASTS USED IN I&M'S RECENT (NOVEMBER 2015) IRP SUBMITTAL?**

[32] The Company and AEP's assumption/position around the prospect of a $CO_2$ carbon tax has been consistently assuming such a value/price in the AEP Fundamental Analysis group's "base" pricing projections since approximately the '2008' vintage forecasts; through the 2015 vintage forecast. The initial *timing* of such $CO_2$/carbon pricing in those earlier forecasts started around the year 2015, and has gradually migrated to the currently-assumed 2022 effective date.

A. Yes, the forecasted pricing used in I&M's 2015 IRP is the same for all scenarios represented on TABLE 4.

## VIII. <u>EVALUATION OF MODELING RESULTS</u>

**Q. BASED ON THESE INPUT PARAMETERS, WHAT WERE THE RESULTS OF THE ROCKPORT UNIT DISPOSITION ANALYSES PERFORMED IN PLEXOS®?**

A. Attachment SCW-4-1 and Attachment SCW-4-2 offer tabular summarizations and comparison of the modeling results for the three primary disposition options for Rockport Unit 2 that were outlined in TABLE 1. Attachments SCW-4A through 4E offer a broader view of the results for the BASE (pricing) Forecast and each of the four alternative commodity pricing scenarios defined in TABLE 4 above.

Again, these modeling results represent <u>relative</u> cost analyses, meaning each are compared to one another in the determination of the "least-cost" alternative outcome. Given that, Attachment SCW-4-1 and Attachment SCW-4-2 reflect the relative costs of the alternative options that would call for the 'return and replacement' of Rockport Unit 2 (Options #1B and #2) when *compared to* a reference alternative. For purpose of these economic assessments, the reference alternatives were established as being each of the "Install SCR" alternatives—Option #1A and Option #1B.

Attachment SCW-4-1 offers a comparison versus *Option #1A* as the reference view. Here the analysis is assessing the relative economics of not only the Rockport Unit 2 SCR Project, but also the eventual prospect of further retrofits on Rockport Unit 2; all versus options that would return the unit to the Lessors in the relative near-term and replacing with alternative resources.

Attachment SCW-4-2 offers a different perspective by offering a similar relative comparison, but with *Option #1B* as the reference view. This comparison rather focuses on the relative economics of the Rockport Unit 2 SCR Project nearly *exclusively*—specifically, for Option #2 vs. Option #1B. The reason for this is that subsequent to the year 2022, there are essentially little-to-no cost differences between those two alternatives as both are setting forth largely the same Rockport Unit 2 "replacement" resource profile.

**Q. PLEASE SUMMARIZE THE RESULTS IN ATTACHMENTS SCW-4-1 AND SCW-4-2.**

A. <u>Attachment SCW-4-1</u>:

This attachment offers an all-encompassing view of the relative modeling results for the evaluations performed in Plexos®. It is segregated into the five sets of future commodity pricing scenarios—displayed vertically—that were identified in TABLE 4, all vis-à-vis Option #1A. Supporting information for each of those option-specific pricing scenario views is offered individually as part of supporting Attachments SCW-4A through 4E.

Focusing first on the relative disposition results under the "BASE Forecast" commodity pricing scenario, it suggests that the Rockport alternative "SCR Retrofit Rockport 2 by 12/2019; then Return and Replace with various resource alternatives (CC, CTs, AD, CHP, renewables, and incremental DSM) by 1/2023" (Option #1B) would be <u>more costly than Option</u>

#1A by $84 million over the long-term study period. Moving down the attachment to assess the "sensitivity" pricing scenarios, Option #1B is more costly by amounts ranging from $349 million for the "Higher Band" price scenario; to being $131 million *less* costly under the "Lower Band" price scenario.

Focusing next on the other Rockport Unit 2 disposition alternative modeled, the "*No* SCR Retrofit, but Return and Replace with various resource alternatives by 1/2020 (Option #2) would be more costly than Option #1A by $322 million under the "BASE" pricing scenario. It also indicates that Option #2 is more costly by amounts ranging from $621 million to $99 million; again under the same respective long-term "Higher Band" and "Lower Band" pricing scenarios.

Attachment SCW-4-2:

Now considering these results from the perspective of Option #1B, under BASE commodity pricing scenario, it indicates that Option #2 would be more costly than Option #1B by $239 million over the long-term study period. Moving down the attachment to assess the "sensitivity" pricing scenarios, Option #2 is more costly by amounts ranging from $272 million for the "Higher Band" price scenario, to $230 million for the "Lower Band" pricing scenario.

**Q. WHAT ADDITIONAL OBSERVATIONS AND CONCLUSIONS CAN YOU DRAW FROM THE ECONOMIC COMPARISONS OFFERED IN ATTACHMENTS SCW-4-1 AND SCW-4-2?**

A. In general, the Plexos® results summarized in Attachment SCW-4-1 and Attachment SCW-4-2 indicate that, as compared to Option #2, the Rockport

Unit 2 SCR Project—reflected in both Option #1A *and* Option #1B—is economically-favored across the full range of long-term pricing scenarios modeled. Therefore, assessing these modeled CPW differences between "Option #1A / Option #1B" and Option #2 that are reflective of these significantly discrete long-term fundamental commodity pricing elements—i.e., inclusive of an approximate -1.0/+1.0 standard deviation around volatile natural gas pricing[33]—it would indicate that a nearer-term solution that would call for the retrofitting of Rockport Unit 2 with SCR technology by December 31, 2019, would be the most economical option for I&M and its customers.

Further, Option #1A represents a unit disposition alternative that is intended to offer a potential longer-term perspective around the economic viability of Rockport Unit 2. As previously indicated in this testimony, however, any decisions around the subsequent required environmental retrofits for that unit—chiefly, a DFGD installation by December 2028—would be considered as part of a future CPCN application before this Commission. What the relative "Option #1A versus Option #1B" economics *would* indicate is that it is currently "too close to call" in terms what that future disposition of the unit might be *beyond* what has clearly been demonstrated for Option #1B (i.e., through the unit's potential Lease termination date of December 2022). Therefore, the results suggest that the proposed Rockport Unit 2 SCR Project solution may also be viewed as preserving an option for I&M and its customers to consider the prospect of continuing to operate Rockport Unit 2

[33] See TABLE 4 pricing scenario descriptions.

over the long-term (Option #1A) by ultimately retrofitting it with DFGD technology as required under the Modified Consent Decree.

## IX. "CARBON" RISK ASSESSMENT

**Q. DID I&M CONSIDER THE PROSPECTS FOR POTENTIAL FUTURE CARBON REGULATION IN THIS ECONOMIC ANALYSIS?**

A. Yes. As discussed in TABLE 4 and immediately thereafter, the Company considered—as a cost/valuation "proxy" for modeling purposes—a presumed "carbon tax" effective in the year 2022. As identified on Attachment SCW-2, the level of this carbon tax that was incorporated into the long-term fundamental pricing forecast initiates on the order of $15 per tonne ('real' [2014] dollars) and was incorporated for not only the 'BASE' alternative pricing scenario, but was also applied in the respective 'Lower Band' and 'Higher Band' alternative scenarios. Hence, the modeling results inherently considered the relative dispatch cost "penalty" attributable to the generation costs of higher-$CO_2$ emitting coal-fired resources—such as Rockport Unit 2—vis-à-vis other (non-coal) resource alternatives.[34] Recognizing this penalty, however, the Plexos® long-term, life cycle study period results previously summarized continued to point to the SCR-retrofit "Option #1" (*either* "Option #1A" or "Option #1B") as being the least-cost unit disposition option for Rockport Unit 2.

[34] It is important to realize, however, that such $CO_2$ pricing assumptions would naturally have correlative impacts on other commodity pricing; namely the price of natural gas and the price of (PJM) energy.

**Q. WERE THE IMPLICATIONS OF EPA'S FINAL CLEAN POWER PLAN SPECIFICALLY REFLECTED IN THE MODELED ECONOMIC EVALUATIONS FOR ROCKPORT UNIT 2?**

A. No, not specifically. Given that the final CPP rulemaking was released relatively recently,[35] the states—including Indiana—have yet to potentially offer binding state implementation plans, its underlying complexity, as well as on-going legal challenges; it was not reasonable to attempt to address/model elements of the rule. Moreover, as indicated by Company witness Hendricks, I&M is currently in the process of reviewing these rulemakings and must undertake significant new analyses to understand the impacts of the final CPP working with other stakeholders in the coming months and years to better understand the requirements of the final CPP, and to work with state agencies on the state's response to it.

The final CPP did not seek to establish a carbon price, or "tax", in order to achieve reduction of $CO_2$ emissions from fossil generation units. Rather, as more fully described by Mr. Hendricks, the rule is centered on the achievement of future state-specific $CO_2$ emission reduction targets that were predicated on a set of suggested "building block" metrics. Despite that complexity and uncertainty, it was reasonable to attempt to at least "proxy" the potential relative economic implication on Rockport Unit 2 via assessing the impact of such $CO_2$/carbon pricing would have on generation/output. This was accomplished through the (incremental) variable/dispatch cost 'penalization' of the coal-fired Rockport Unit 2 via the introduction of such a

[35] Publically released on August 3, 2015; and published in the *Federal Register* on October 23, 2015.

$CO_2$/carbon pricing proxy. By way of incorporating these carbon pricing proxies, the Company believes—as supported by the testimony of Mr. Hendricks—it has reasonably estimated the potential impact of the Clean Power Plan on Rockport Unit 2. This includes the incorporation of a "High Carbon" pricing scenario which was determined by the AEP Fundamental Analysis as being a higher-than-anticipated threshold level of $CO_2$ pricing approximately *two-thirds above* the level assumed in the 'BASE' pricing scenario, or at an adjusted level of roughly $25 per tonne (real [2014] dollars), also effective in the year 2022.

**Q. WHAT DID THOSE PLEXOS® MODELING RESULTS INDICATE?**

A. As previously summarized in this testimony and on Attachment SCW-4-1, when incorporating a $15 per tonne (real) $CO_2$ pricing proxy as part of the "BASE" pricing scenario, the Option #1A alternative continued to be economically advantaged versus either of the "Option #1B" and "Option #2" (return and replace) alternatives by amounts ranging from $84 million (vs. Option #1B) to $322 million (vs. Option #2). Alternatively, when incorporating the 'High Carbon' $25 per tonne (real) $CO_2$ pricing proxy, the Option #1A alternative was now slightly more costly than Option #1B by $90 million; while it continued to be economically advantaged versus Option #2 by $142 million.

**Q. WHAT ARE THE IMPLICATIONS OF $CO_2$/CARBON WHEN ASSESSING THE RELATIVE *SHORTER-TERM* DECISION AROUND THE ROCKPORT 2 SCR PROJECT WHEN COMPARING OPTION #2 and OPTION #1B, ONLY?**

A. Over the relative shorter term, the results suggest that $CO_2$ would likely not be a significant issue. Recognizing that, effectively, Option #1B and Option #2 are *largely focused on the relative economics of those alternatives for the years 2020 through 2022 (only)*, one would anticipate that by virtue of a 2022 start-date for the CPP (represented by a 2022 carbon tax proxy start-date in the modeling), it would have minimal impact on the relative economic results. This fact is borne out when comparing the relative results found on Attachment SCW-4-2. When examining the (CPW) cost differences between Option #2 and Option #1B, one would note that even under varying long-term commodity pricing scenarios—including "High Carbon" and "No Carbon" scenarios—the results are nearly the same. This indicates that the relative make-up of these respective option views is largely the same *post*-2022. In other words, both cases assume Rockport Unit 2 would be returned to the Lessors and replaced with comparable (non-coal) resources at that point which would largely mitigate any relative cost exposure tied to $CO_2$/carbon.

Considering further that the recent U.S. Supreme Court decision to stay the CPP could potentially result in the rule's implementation being delayed by one or more years beyond 2022—under the further assumption that the Court would ultimately re-instate the rule—would suggest that $CO_2$/carbon will likely have no bearing on this nearer-term decision to install an SCR on Rockport Unit 2.

## X. OPTIONALITY OFFERED BY THE ROCKPORT UNIT 2 SCR PROJECT

**Q. YOUR TESTIMONY HAS PREVIOUSLY MENTIONED THE "OPTIONALITY" THAT WOULD BE AFFORDED I&M AND ITS CUSTOMERS BASED ON A DECISION TO ALLOW ROCKPORT UNIT 2 TO CONTINUE TO OPERATE BY WAY OF INSTALLING THE SCR PROJECT. PLEASE ELABORATE.**

A. The Rockport Unit 2 SCR Project could potentially serve to "bridge" the unit for a period of 9 years; beginning with the required December 2019 SCR in-service date up to the timeframe in which a more capital-intensive DFGD retrofit which, for purpose of the analysis, would be required to be installed by December 31, 2028. For instance—as outlined on TABLE 3—at an installed capital cost of $189/kW, the Rockport Unit 2 SCR Project would be just a fraction of the cost of either replacement-build CC, CT, AD and/or CHP resources.

Attachment SCW-5, offers a shorter-term (*i.e.*, 13-year; 2016-2028) CPW comparison of the Option #1A versus Option #2 alternatives. It demonstrates that the relative economic advantage of Option #1A versus Option #2 over this shorter timeframe (through 2028) is apparent. That relative CPW benefit is, on average, nearly $43 million per year—compared to an average per year advantage of nearly $9 million over the full modeled long-term optimization period, including end-effects. This would suggest that the Rockport Unit 2 SCR Project would offer significant relative option value over the period *leading up to* the next potential major re-investment; the installation of DFGD by the end of 2028.

**Q. WOULD THIS RELATIVE NEAR-TERM ECONOMIC ADVANTAGE ALSO BE APPLICABLE FOR THE EVEN SHORTER PERIOD LEADING UP TO THE POTENTIAL "RETURN TO LESSOR" DISPOSITION ALTERNATIVE UNDER OPTION #1B?**

A. Yes, even more so. Attachment SCW-5 also offers a shorter-term (*i.e.*, 7-year; 2016-2022) CPW comparison of the Option *#1B* versus Option #2 alternatives. It demonstrates that the relative economic advantage of Option #1B versus Option #2 over this shorter timeframe (through 2022) is even *more* pronounced, with the CPW benefit being, on average, approximately $65 million per year.

In summary, this would also suggest that the Rockport Unit 2 SCR Project would afford the ability to capitalize on significant relative value it would offer I&M and its customers; even for a brief, 3-year period that would lead up to a potential Return to Lessor disposition.

## XI. VALIDATION OF RESULTS VERSUS I&M'S 2015 IRP

**Q. EARLIER YOUR TESTIMONY INDICATED THAT THE OPTIONS ANALYZED WERE CONSISTENT WITH CERTAIN "CASES" OFFERED AS PART OF I&M'S RECENT IRP FILING (TABLE 2). HOW DID THE ECONOMIC RESULTS COMPARE BETWEEN THOSE ANALYSES?**

A. Attachment SCW-6 provides a comparison of the relative CPW differentials between the results set forth in the 2015 IRP[36] and these instant results. For example, this demonstrates that the 'CPW cost difference' between Option

[36] I&M 2015 IRP; Table 22 (pg. 120)

#1B and Option #2 under BASE pricing, as shown on Attachment SCW-4-2, was $239 million. The relative "as-filed" CPW cost difference for the comparable options from the IRP was $465 million. However, subsequent to the IRP filing it was determined that there was an overstatement of cost of approximately $205 million in the development of the "Fleet Modification w/ NO RK U2 SCR" IRP case results. Therefore the "as-corrected" CPW cost difference is restated at $260 million, or, nearly the same figure as the current analysis.

Also note that the CPW cost difference between Option #1A and Option #1B, as shown also on Attachment SCW-4-1, was $84 million. The relative "as-filed" CPW cost difference for the comparable options from the 2015 IRP was $174 million. This difference was a function of having utilized an updated set of Rockport Plant long-term projections for plant O&M expense and capital expenditures that was established subsequent to the development of the IRP.

**Q. WERE THERE OTHER MATERIAL DIFFERENCES BETWEEN THE UNDERLYING DATA PARAMETERS AND ASSUMPTIONS UTILIZED IN I&M's 2015 IRP AND THIS LATEST ROCKPORT UNIT 2 DISPOSITION ANALYSIS?**

A. No. As indicated earlier one of the major underpinnings of such analyses, long-term fundamental commodity pricing projections were the same as those pricing forecasts used in the IRP. Further, the underlying I&M load and peak demand forecast utilized is also identical to the forecast used in the IRP. Additionally, the cost and performance parameters associated with the alternative replacement resources (including, CC, CT, AD, CHP, wind, solar and incremental DSM) were all consistent with the parameters employed in I&M's recently-submitted 2015 IRP.

**Q. WOULD THE CONCLUSION THAT INSTALLING AN SCR ON ROCKPORT UNIT 2 IS THE SUPERIOR OPTION CHANGE *EVEN IF* DIFFERENT ASSUMPTIONS HAD BEEN UTILIZED AS PART OF THIS POST-IRP ANALYSIS?**

A. No. For instance, as this testimony suggests, if the decision materially boils down to the comparison of two "nearer-term" options—*Option #1B versus Option #2*—then both of these options would likely require the same level and type of replacement resources beginning in roughly the same timeframe—2023 (Option #1B) versus 2020 (Option #2). Therefore the relative CPW cost difference between those two views would not be materially impacted *irrespective* of the assumptions supporting those replacement resources—including long-term fundamental pricing and load projections—as each of those options would be impacted nearly equivalently.

To validate this point, a sensitivity option was performed which served to "delay" the Rockport Unit 2 replacement resources required under Option #2 by three years (i.e., from 1/2020 -to- 1/2023), or a disposition date *consistent* with Option #1B. As reflected on Attachment SCW-4A, those changes resulted in "(Sensitivity) Option #2A" having relative small CPW cost changes versus Option #2. In fact, under BASE pricing, this Option #2A would now be even more costly versus Option #1A by $346 million (as compared with a $322 million CPW cost difference when comparing Option #2 versus Option #1A).

Further, recall that when examining the results on Attachment SCW-4-2 the relative CPW cost differences between Option #2 and Option #1B are fairly insignificant (ranging from $230 million -to- $272 million, only) *irrespective* of the varied fundamental commodity pricing projection assumed, including natural gas and carbon.

## XII. CONCLUSIONS AND RECOMMENDATIONS

**Q. DO THE ROCKPORT UNIT 2 DISPOSITION ANALYSES YOU HAVE DESCRIBED EXAMINE THE CRITERIA SET FORTH IN INDIANA CODE § 8-1-8.7-3(b)(7) AND § 8-1-8.7-3(b)(8)?**

A. Yes. As it pertains to part (b)(7), the Company has set forth the relative cost and feasibility of a Rockport Unit 2 retirement (or, in this circumstance, return to Lessors) option and demonstrated that the cost of that alternative would exceed that of the proposed Rockport Unit 2 SCR Project.

In regard to part (b)(8), the Company has likewise implicitly set forth that the dispatch priority of this proposed $NO_X$-controlled Rockport Unit 2 will not be adversely impacted based on the resulting variable cost profiles within the economic analyses previously described. It would be anticipated that the unit's annual capacity factor will not be significantly different from levels had this SCR retrofit not been installed.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY FROM THE PERSPECTIVE OF THE "UNIT DISPOSITION ANALYSES" PERFORMED.**

A. Several final summarizations and conclusions can be drawn from the information offered within this testimony:

(1) I&M has performed robust unit disposition economic analyses that would point to the nearer-term retrofitting of Rockport Unit 2 with SCR technology by December 31, 2019 (via either Option #1A or Option #1B) as being a reasonable and least-cost solution over the long-term economic study period evaluated when compared to a view that would not install an SCR but rather terminate the Rockport Lease as of that same date and paying the Lessors a stipulated Lease Termination Value (Option #2).

(2) The Rockport Unit 2 SCR Project would serve to economically preserve a future option to potentially install DFGD environmental controls on Unit 2 by the end of 2028, as required under the Modified Consent Decree. However, even under the assumption I&M would ultimately choose *not* to proceed with a Unit 2 DFGD retrofit, the economic analysis clearly supports implementation of the Rockport Unit 2 SCR Project.

(3) It is in the best interest of its customers to leverage the current investment of a thermally-efficient Rockport Unit 2 by recommending it be retrofitted with SCR technology by December 31, 2019, so as to be in compliance with the Modified Consent Decree as well as other potential EPA rulemaking that would require the reduction of $NO_X$ emissions.

**Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

## VERIFICATION

I, Scott C. Weaver, Managing Director – Resource Planning & Operational Analysis of the American Electric Power Service Corporation, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Date: 10/19/16

Scott C. Weaver

Scott C. Weaver

# Attachment SCW-1

## Overview of resource planning-related criteria used in I&M's analyses

# I. RESOURCE NEED

## A. Description of I&M's customer base

I&M's customer base consists of both retail and sales-for-resale customers located in northern Indiana and southern Michigan. Approximately 587,000 residential, commercial, industrial and other retail end-use customers are served by the Company; with approximately 459,000 residing in Indiana. These I&M-Indiana retail customers represent over 66 percent of I&M's total (retail and wholesale) energy sales in 2015, with the balance coming from retail sales to customers in Michigan, as well as FERC-authorized sales to several electric cooperatives and municipalities that provide wholesale service for ultimate distribution and resale to their end-use customers.

## B. Overview of I&M's peak demand requirements

To ensure the continuation of reliable service, the peak demand of its customer base represents one of the primary underpinnings of any capacity resource plan. The peak load requirement of all I&M retail and sales for resale wholesale customers is seasonal in nature, with distinctive peaks occurring in both the summer and the winter seasons. Historically, I&M's larger peak demand has been recorded in the summer season, with the all-time actual peak being 4,837 MW, which occurred on July 21, 2011 (4,479 MW on a "weather-normalized", non-PJM coincident basis).[1]

The following **Table 1-1** offers the AEP Economic Forecasting June, 2015 projection of I&M and, for comparison, overall AEP-East (summer) peak demand and internal load, with peaks adjusted to recognize overall PJM zonal diversity. Over the next 10 year period (through 2025) I&M's summer demand is anticipated to remain relatively flat with a compound annual growth rate ("CAGR") of only 0.04 percent, or by a total of 17 MW; relative results which are below those of the overall AEP-East region for the same period. The peak demand CAGR for I&M does increase to 0.22% over the next 20 years, or by a total of 182 MW.

---

[1] I&M's most recent annual (2015) actual summer peak was 4,398 MW, occurring on July 28, 2015 (4,528 MW on a weather-normalized, non-PJM coincident basis).

## Table 1-1

**Forecasted (Summer) Peak Demand and Internal Load**
I&M (Total Company) and AEP-East
**Internal Forecast BEFORE DSM, with Implied PJM (Peak) Diversity Factor**
(June-2015 Fcst)

| | Peak Demand (MW) | | | Internal Load (GWh) | |
|---|---|---|---|---|---|
| Year | I&M | AEP-East* | Year | I&M | AEP-East* |
| 2016 | **4,277** | 19,555 | 2016 | **25,753** | 120,199 |
| 2017 | **4,292** | 19,839 | 2017 | **25,854** | 121,873 |
| 2018 | **4,216** | 19,830 | 2018 | **25,351** | 121,613 |
| 2019 | **4,223** | 19,890 | 2019 | **25,396** | 121,880 |
| 2020 | **4,218** | 19,917 | 2020 | **25,432** | 122,194 |
| 2021 | **4,238** | 20,041 | 2021 | **25,485** | 122,583 |
| 2022 | **4,252** | 20,138 | 2022 | **25,551** | 123,061 |
| 2023 | **4,258** | 20,207 | 2023 | **25,615** | 123,546 |
| 2024 | **4,267** | 20,266 | 2024 | **25,674** | 123,987 |
| 2025 | **4,293** | 20,406 | 2025 | **25,735** | 124,384 |
| 2026 | **4,311** | 20,508 | 2026 | **25,801** | 124,803 |
| 2027 | **4,329** | 20,607 | 2027 | **25,867** | 125,241 |
| 2028 | **4,339** | 20,683 | 2028 | **25,946** | 125,759 |
| 2029 | **4,360** | 20,802 | 2029 | **26,020** | 126,229 |
| 2030 | **4,376** | 20,910 | 2030 | **26,079** | 126,658 |
| 2031 | **4,392** | 21,018 | 2031 | **26,128** | 127,065 |
| 2032 | **4,397** | 21,082 | 2032 | **26,187** | 127,514 |
| 2033 | **4,427** | 21,245 | 2033 | **26,262** | 128,007 |
| 2034 | **4,439** | 21,325 | 2034 | **26,340** | 128,501 |
| 2035 | **4,459** | 21,444 | 2035 | **26,417** | 128,987 |

| | | | | | |
|---|---|---|---|---|---|
| 10-Year (2016-2025): | | | 10-Year (2016-2025): | | |
| Total Growth | **17** | 851 | Total Growth | **(18)** | 4,186 |
| Compound Annual Growth Rate | **0.04%** | 0.47% | Compound Annual Growth Rate | **-0.01%** | 0.38% |
| 20-Year (2016-2035): | | | 20-Year (2016-2035): | | |
| Total Growth | **182** | 1,889 | Total Growth | **664** | 8,789 |
| Compound Annual Growth Rate | **0.22%** | 0.49% | Compound Annual Growth Rate | **0.13%** | 0.37% |

* AEP-East includes Ohio-Wires customers

### C. PJM reserve margin criterion

It is assumed that the underlying *minimum* reserve margin criteria to be utilized in the determination of I&M's capacity needs assessment is the PJM board-approved Installed Reserve Margin ("IRM") level. Currently that IRM level is 16.4 percent; but will be increasing to 16.5 percent effective with the most recently-established, 2019/20, PJM (3-year forward) planning year. For long-term resource planning purposes, it is assumed this latter level will remain through the Company's 20-year long-term planning period.

## D. I&M and AEP obligation to provide reserve margin in PJM

On October 1, 2004, AEP transferred functional control of its transmission facilities as well as its generation dispatch, including the transmission and generation facilities owned by its operating companies, including I&M, to PJM. With that, the PJM Reliability Assurance Agreement defines the requirements surrounding various reliability criteria, including measuring and ensuring capacity adequacy. In that regard, each Load Serving Entity ("LSE") in PJM is required to provide an amount of capacity resources determined by PJM based on several factors, including PJM's IRM requirement. This requirement is itself based on the amount of resources needed to maintain, among other things, a loss-of-load expectation of one day in ten years. Additionally, peak demand diversity among the LSEs and PJM, and generating asset-assumed equivalent forced outage rates ("EFOR") represent other factors impacting such required minimum reserve levels.

Further, beginning in the initial 2007/08 PJM "planning year", through today—*i.e.,* for the most recently-established 2019/20 planning year—AEPSC, as agent for the AEP-East LSEs, including I&M, has given annual notice of its intent to elect to continue to opt-out of the PJM Reliability Pricing Model ("RPM") three-year forward capacity auction and, instead, meet its capacity resource obligation through participation in the optional, FERC-authorized Fixed Resource Requirement ("FRR") construct. FRR requires AEP and I&M to set forth its future capacity resource profile and position under, essentially, a "self-planning" format that is predicated upon ensuring the stand-alone achievement of its future customer peak demand *plus* IRM requirements (*i.e.*, 'UCAP Obligation'). The current AEP Power Coordination Agreement ("PCA") offers a loosely-integrated arrangement in which the participating operating companies (I&M, APCo and KPCo) are expected to be self-sufficient for both capacity and energy requirements. Despite that PCA requirement, these three AEP affiliates have continued to elect to opt-out of the capacity auction and participate jointly as an "FRR" planning entity, at least through the 2019/20 Planning Year, so as to enjoy a) the inherent capacity position hedging capabilities offered to a larger-scale planning entity; and b) a lower overall IRM requirement vis-à-vis the implied reserve margin that have resulted from prior cleared RPM capacity auctions.

Currently it is I&M's position that the interests of its customers are better preserved under that FRR framework. While I&M, and the other AEP-East operating company participants in the PCA—beginning with the *next* (2019/20) PJM-RPM planning year—reserve the option of electing to participate in future RPM 3-year forward auction process.

## E. Capacity Performance

On June 9, 2015 FERC issued an order largely accepting PJM's proposal to establish a new "Capacity Performance" product. The resulting PJM rule requires future capacity auctions to transition from current or 'Base' capacity products to Capacity Performance products. Capacity Performance resources would be held to stricter requirements than current Base resources and, with that, could be assessed additional charges for UCAP sources failing to deliver energy when called upon during an (hourly) emergency performance event or, potentially, receive credits if anticipated delivered energy during such events were at levels above offered UCAP amounts for those sources.

I&M and AEP are in the process of reviewing the full implications of the order and recognizing that final tariffs addressing Capacity Performance have not been issued by PJM. Despite this uncertainty, this IRP incorporates the following assumptions for Capacity Performance values as it pertains to certain intermittent resources, in order to address this potential Capacity Performance rulemaking, anticipated to be fully-effective with the 2020/21 PJM planning year:

- Run-of-River hydro unit nameplate capacity will offer no capacity value due to the intermittency of supply.
- Wind resources will also offer no capacity value due to the intermittency of its supply, a reduction from current PJM's criterion limiting UCAP contribution to 13 percent (of nameplate) for new wind sources.
- Solar resources will be valued at the 'full' 38 percent of nameplate capacity rating, which represents the current PJM UCAP limitation criterion for new solar resources.

This long-term I&M capacity profile assumes that during the 2020/21 PJM planning year all capacity resources will need to be Capacity Performance products. *It is possible that these resources may ultimately be combined, or "coupled", and offered into the PJM market as Capacity Performance resources.* Once the final PJM Capacity Performance tariffs are approved and published, the Company will investigate methods to maximize the utilization of its current (and future) intermittent resource portfolio within that construct. An example could be the additional coupling of run-of-river hydro, wind and potential solar resources in a way that would mitigate non-performance risk. While there could be some uplift in intermittent resource UCAP contribution from such a potential 'coupling' approach, it would be anticipated any additional amounts would be neglible in the context of the possible replacement of the Company's 1,105 MW share of Rockport Unit 2.

## F. I&M's current available capacity resources

To meet the most recent UCAP Obligation and annual energy requirements of its customers, as part of its FRR obligations in PJM for the current 2016/17 "delivery year", I&M is relying on 4,524 MW of owned—or for which it currently has a long-term purchase entitlement—generating capability. The make-up of I&M's PJM-recognized installed capability ("ICAP") includes a portfolio of generating resources identified in the following **Table 1-2**:

**Table 1-2**

COAL:

- ✓ Rockport Unit 1 (658 MW) located in Spencer County, IN. In-service 1984
- ✓ Rockport Unit 2 (650 MW) located in Spencer County, IN. In-service 1989
- ✓ Rockport Unit 1 (460 MW) located in Spencer County, IN. [2] In-service 1984
- ✓ Rockport Unit 2 (455 MW) located in Spencer County, IN. [3] In-service 1989

NUCLEAR:

- ✓ D.C. Cook Unit 1 (1,006 MW) located in Bridgeman, MI. In-service 1975
- ✓ D.C. Cook Unit 2 (1,053 MW) located in Bridgeman, MI. In-service 1978

[2] This reflects I&M's 70% purchase entitlement from the (50%), AEP Generating Company (AEG) ownership share of the (total) 1315 MW unit.
[3] This reflects I&M's 70% purchase entitlement from the (50%), AEG share of the 1300 MW unit that is currently under lease to non-affiliate Lessors.

HYDRO:

- ✓ (41) small, run-of-river units (18 MW total) located at 6 facilities in IN & MI

WIND [4]:

- ✓ Fowler Ridge Wind Farm (18 MW) located in Benton County, IN. In-service 2009
- ✓ Wildcat Wind Farm (13 MW) located in Grant, Howard, Madison and Tipton Counties, IN. In-service 2013
- ✓ Headwaters Wind Farm (26 MW) located in Randolph County, IN. In-service 12/2014

SOLAR [5] [6]:

- ✓ Deer Creek Solar facility (1.1 MW) located in Marion, IN. In-service 12/2015

*Plus:*

- ✓ I&M's 7.85 percent (~166 MW) power participation ratio (PPR) share if the Ohio Valley Electric Corporation's (OVEC) Clifty Creek and Kyger Creek coal-fired facilities (2,140 MW, combined), located in southern IN and southern OH, respectively.

TOTAL (2016/2017 PJM Planning Year) **4,524** MW

*Note: Tanners Creek Units 1-4 were retired on June 1, 2015*

## G. Anticipated future capacity rerates

Nearly concurrent with the planned Rockport Unit 2 (and Unit 1) SCR retrofits in late-2019 and late-2017, respectively, current planning also projects both units would be uprated by a total of 36 MW (each) to reflect the benefits of the AEP System's LP Turbine improvement program. Likewise, D. C. Cook Unit 2 is

[4] Recognizing the intermittent nature of *wind* resources, for PJM ICAP-determination purposes, this represents the PJM-recognized initial 13 percent portion of the total nameplate rating from I&M's share of the (150-MW, combined) Fowler Ridge I & II Renewable Energy Purchase Agreements (REPA), the (100-MW) Wildcat REPA, and the (200-MW) Headwaters REPA. Note, however, that the subsequent PJM-authorized capacity rating for I&M's share of Fowler I & II has been decreased to a total of 13 MW from the initial in-service recognized level of 19.5 MW (150 MW x 13%). In all cases, however, this 13 percent level of ICAP determination is assumed to be reduced to zero beginning with the full implementation of the PJM-RPM "Capacity Performance" construct effective with the 2020/21 planning year.

[5] Recognizing the intermittent nature of *solar* resources, for PJM ICAP-determination purposes, this represents the PJM-recognized initial 38 percent portion of the total nameplate rating from I&M's share of the Company-owned (2.9-MW) Deer Creek solar facility. Likewise, however, this 38 percent level of ICAP determination is assumed to remain at 38 percent effective with the full implementation of the PJM-RPM Capacity Performance construct effective with the 2020/21 planning year.

[6] In addition to the 1.1 MW (2.9 MW nameplate) Deer Creek facility, this does not include three additional I&M solar facilities that are anticipated to be placed into service over the course of 2016, making each not applicable for PJM planning purposes until the subsequent, 2017/18 planning year (Olive solar facility @ 1.9 MW [4.9 MW nameplate]; Twin Branch solar facility @ 1.1 MW [2.9 MW nameplate]; and Watervliet solar facility @ 1.7 MW [4.6 MW nameplate]). This will bring the total solar contribution for I&M in PJM to 5.8 MW (approximately 15 MW nameplate).

projected to experience a 50 MW uprate in late-2016 to reflect a currently-planned HP/LP Turbine replacement. Such uprates would impact the Company's ICAP beginning with the subsequent PJM-RPM planning years.[7]

**H. I&M's anticipated "demand" resources (DSM)**

Demand-Side Management ("DSM") comprised of both "active" and "passive" demand reduction initiatives has been incorporated into the Company's resource planning. Specifically, "active" DSM, in the form of peak-reducing demand response activity has been projected; as well as "passive" DSM, in the form of "around-the-clock" energy efficiency ("EE") programs, which I&M and this Commission has supported for some time, has also been incorporated in the analysis. The following **Table 1-3** identifies the level of I&M (total) demand reduction and EE that are initially anticipated over the forecasted time horizon. Such projected levels of EE were embedded into the Company's long-term load forecast.

While not at all trivial, it is evident however, that even the aggressive demand resource contributions already forecasted for such DSM activity by or around the year 2020 of 363 MW—summarized in Table 1-3—are well below the significant capacity needs that would be at issue when considering the disposition of units on the scale of, particularly, Rockport Unit 2. Likewise, any *incremental* levels of DSM/EE activity over-and-above the projected levels incorporated into I&M's long-term load forecast that could result from the unit's disposition evaluation would also likely provide a very small relative offset to the native generation offered to I&M's resource portfolio by Rockport Unit 2 (1,105 MW as reflected in Table 1-2).

[7] For example, the Rockport Unit 2 (turbine) uprate in "late-2019" would impact I&M's capacity position beginning with the 2020/21 PJM-RPM planning year.

## Table 1-3

**Forecasted Demand Response (DR) and Energy Efficiency (EE)**
I&M (Total Company) and AEP-East
(June-2015 Fcst)

| | (CURRENT) "ACTIVE" PJM-APPROVED DEMAND RESPONSE Peak Reduction (MW) | | + (PROJECTED) "PASSIVE" DEMAND RESPONSE (ENERGY EFFICIENCY) Peak Reduction (MW) | | = TOTAL DEMAND RESPONSE Peak Reduction (MW) | |
|---|---|---|---|---|---|---|
| Year | I&M | AEP-East* | I&M | AEP-East* | I&M | AEP-East* |
| 2016 | **315** | 630 | **26** | 134 | **341** | 764 |
| 2017 | **315** | 671 | **37** | 187 | **352** | 858 |
| 2018 | **315** | 671 | **48** | 243 | **363** | 914 |
| 2019 | **298** | 678 | **57** | 290 | **355** | 968 |
| 2020 | **298** | 678 | **64** | 324 | **363** | 1,002 |
| 2021 | **298** | 678 | **69** | 350 | **368** | 1,028 |
| 2022 | **298** | 678 | **73** | 371 | **371** | 1,049 |
| 2023 | **298** | 678 | **71** | 385 | **369** | 1,063 |
| 2024 | **298** | 678 | **75** | 394 | **374** | 1,072 |
| 2025 | **298** | 678 | **76** | 402 | **375** | 1,080 |
| 2026 | **298** | 678 | **77** | 406 | **375** | 1,084 |
| 2027 | **298** | 678 | **77** | 408 | **376** | 1,086 |
| 2028 | **298** | 678 | **77** | 409 | **376** | 1,087 |
| 2029 | **298** | 678 | **77** | 410 | **376** | 1,088 |
| 2030 | **298** | 678 | **78** | 412 | **376** | 1,090 |
| 2031 | **298** | 678 | **78** | 414 | **376** | 1,092 |
| 2032 | **298** | 678 | **78** | 415 | **377** | 1,093 |
| 2033 | **298** | 678 | **79** | 418 | **377** | 1,096 |
| 2034 | **298** | 678 | **79** | 418 | **377** | 1,096 |
| 2035 | **298** | 678 | **79** | 420 | **377** | 1,098 |

| | (PROJECTED) CUMULATIVE ENERGY EFFICIENCY (GWh) | |
|---|---|---|
| Year | I&M | AEP-East* |
| 2016 | **191** | 788 |
| 2017 | **268** | 1,056 |
| 2018 | **345** | 1,347 |
| 2019 | **416** | 1,593 |
| 2020 | **475** | 1,781 |
| 2021 | **517** | 1,913 |
| 2022 | **542** | 2,018 |
| 2023 | **558** | 2,094 |
| 2024 | **568** | 2,145 |
| 2025 | **574** | 2,177 |
| 2026 | **578** | 2,195 |
| 2027 | **580** | 2,204 |
| 2028 | **582** | 2,212 |
| 2029 | **584** | 2,221 |
| 2030 | **586** | 2,230 |
| 2031 | **588** | 2,239 |
| 2032 | **589** | 2,248 |
| 2033 | **591** | 2,256 |
| 2034 | **593** | 2,264 |
| 2035 | **595** | 2,272 |

*Reflects forecasted DR and EE levels embedded into the Company's June-2015 load & peak demand forecast... This would <u>exclude</u> 'incremental' levels of such resources that would result from the Rockport Unit 2 disposition evaluation performed.*

* AEP-East includes Ohio-Wires customers and the prescribed EE reductions through 2025 under Ohio SB 221.

**I. SUMMARY: I&M's "GOING-IN" future PJM annual capacity positions**

Assuming that the I&M LSE was viewed individually as part of a PJM-planning perspective, the following **Table 1-4** offers a long-term (20-year) overview of such an I&M "stand-alone" capacity position within PJM though the 2035/36 PJM planning year. This view effectively assumes that the Company would continue to elect to participate in the PJM-RPM as an FRR (*i.e.*, self-planning) entity as opposed to participating in PJM's capacity auction construct. Further it assumes, as a "going-in"—or base assumption—that Rockport Unit 2 (and Unit 1) would continue to contribute ICAP throughout the planning horizon. As reflected in the Table 1-4 column identified as "Net Position w/ New Capacity" (col. 20), I&M would be "long" capacity by 159 MW beginning with the most recent (2019/20) 3-year forward PJM-RPM Base Residual Auction planning year.[8] This demonstrates and confirms that, not surprisingly, I&M would immediately be *significantly* exposed—from a stand-alone planning perspective—should a Rockport Unit 2 disposition strategy call for the unit to be returned to the Lessor.

In summary, based on the recommendations set forth in this testimony and, again, assuming that the I&M LSE were viewed individually as part of a PJM-planning perspective, Table 1-4 offers an overview of such an I&M stand-alone capacity position within PJM assuming the Company would continue to elect to be an FRR planning entity. It offers a "going-in" I&M capacity position profile over the next 20 years—*i.e.,* **before** the addition of incremental Plexos® model-selected resources—that reflect, <u>in addition to the recommended December 2019 "Rockport Unit 2 SCR Project" retrofit</u>, the:

- continued advancement of significant demand-side reduction (see Table 1-3);
- ultimate retrofit of Rockport Unit 1 with SCR and DFGD by December 2017 and December 2025, respectively;
- ultimate retrofit of Rockport Unit 2 with DFGD by December 2028; and
- although no ultimate disposition determination has been made, the potential for the retirement of the first D.C. Cook Nuclear Unit (Unit 1) in 2035 at the end of its initial (20-year) relicensing period.

[8] Stated another way, I&M would have 159 MW of capacity resources above the <u>minimum</u> PJM-FRR Installed Reserve Margin criterion of 16.5 percent.

# Table 1-4 "Going-In" Capacity Position

**INDIANA MICHIGAN POWER COMPANY**
**Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)**
**Based on (June 2015) Load Forecast**
2016 (Going-In)

| | | Obligation to PJM | | | | | | | | | | Resources | | | | | | | | | I&M Position (MW) | | PJM Reserve Margin | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Planning Year | | (1) Internal Demand (a) | (2) DSM (b) | (3) Projected DSM Impact (c) | (4) =(1)+(3) Net Internal Demand | (5) Interruptible Demand Response (d) | (6) Demand Response Factor | (7) Forecast Pool Req't (e) | (8) =((4)-((5)*(6)))*(7) UCAP Obligation | (9) Net UCAP Market Obligation (f) | (10) =(8)+(9) Total UCAP Obligation | (11) Existing Capacity & Planned Changes (g) | (12) Net Capacity Sales (h) | (13) Planned Capacity Additions Units | (14) Planned Capacity Additions MW (i) | (15) Annual Purchases | (16) =(11)-(12) + Sum(14) +(15) Net ICAP | (17) AEP EFORd (j) | (18) =(16)*(1-(17)) Available UCAP | (19) BASE UCAP Removed (l) | (20) =((11)-(12) +(15)) *(1-(17)) -(10)-(19) Net Position w/o New Capacity | (21) =(18)-(10)-(19) Net Position w/ New Capacity | Total UCAP Obligation Less DR and IRM | Installed Reserve Margin (IRM) | I&M Reserve Margin Above PJM IRM | Total I&M Reserve Margin |
| 2016 /17 | (k) | 4,213 | (26) | 0 | 4,213 | 223 | 0.953 | 1.095 | 4,381 | 0 | 4,381 | 4,524 | 12 | | | | 4,512 | 3.90% | 4,336 | 0 | (45) | (45) | 3,964 | 16.40% | -1.14% | 15.26% |
| 2017 /18 | (k) | 4,264 | (37) | 0 | 4,264 | 223 | 0.953 | 1.088 | 4,408 | 0 | 4,408 | 4,623 | 9 | | | | 4,614 | 3.44% | 4,455 | 0 | 47 | 47 | 3,982 | 16.50% | 1.18% | 17.68% |
| 2018 /19 | (k) | 4,185 | (48) | 0 | 4,185 | 223 | 0.953 | 1.088 | 4,323 | 0 | 4,323 | 4,654 | 6 | | | | 4,648 | 3.45% | 4,488 | 0 | 165 | 165 | 3,909 | 16.50% | 4.22% | 20.72% |
| 2019 /20 | (k) | 4,193 | (57) | 0 | 4,193 | 223 | 0.953 | 1.088 | 4,331 | 0 | 4,331 | 4,654 | 4 | | | | 4,650 | 3.45% | 4,490 | 0 | 159 | 159 | 3,916 | 16.50% | 4.06% | 20.56% |
| 2020 /21 | | 4,218 | (64) | (26) | 4,192 | 298 | 0.953 | 1.088 | 4,251 | 0 | 4,251 | 4,685 | (65) | | | | 4,750 | 3.45% | 4,586 | 73 | 262 | 262 | 3,915 | 16.50% | 6.69% | 23.19% |
| 2021 /22 | | 4,238 | (69) | (37) | 4,201 | 298 | 0.953 | 1.088 | 4,262 | 0 | 4,262 | 4,685 | (65) | | | | 4,750 | 3.45% | 4,586 | 73 | 251 | 251 | 3,924 | 16.50% | 6.40% | 22.90% |
| 2022 /23 | | 4,252 | (73) | (48) | 4,204 | 298 | 0.953 | 1.088 | 4,265 | 0 | 4,265 | 4,685 | (64) | | | | 4,749 | 3.45% | 4,585 | 73 | 247 | 247 | 3,927 | 16.50% | 6.29% | 22.79% |
| 2023 /24 | | 4,258 | (71) | (57) | 4,201 | 298 | 0.953 | 1.088 | 4,262 | 0 | 4,262 | 4,685 | (64) | | | | 4,749 | 3.45% | 4,585 | 73 | 250 | 250 | 3,924 | 16.50% | 6.37% | 22.87% |
| 2024 /25 | | 4,267 | (75) | (64) | 4,203 | 298 | 0.953 | 1.088 | 4,263 | 0 | 4,263 | 4,665 | (64) | | | | 4,749 | 3.45% | 4,585 | 73 | 249 | 249 | 3,925 | 16.50% | 6.34% | 22.84% |
| 2025 /26 | | 4,293 | (76) | (69) | 4,224 | 298 | 0.953 | 1.088 | 4,287 | 0 | 4,287 | 4,669 | (65) | | | | 4,734 | 3.45% | 4,571 | 73 | 211 | 211 | 3,945 | 16.50% | 5.35% | 21.85% |
| 2026 /27 | | 4,311 | (77) | (73) | 4,238 | 298 | 0.953 | 1.088 | 4,302 | 0 | 4,302 | 4,669 | (65) | | | | 4,734 | 3.45% | 4,571 | 73 | 196 | 196 | 3,958 | 16.50% | 4.95% | 21.45% |
| 2027 /28 | | 4,329 | (77) | (71) | 4,258 | 298 | 0.953 | 1.088 | 4,323 | 0 | 4,323 | 4,669 | (65) | | | | 4,734 | 3.45% | 4,571 | 73 | 175 | 175 | 3,976 | 18.50% | 4.40% | 20.90% |
| 2028 /29 | | 4,339 | (77) | (75) | 4,264 | 298 | 0.953 | 1.088 | 4,331 | 0 | 4,331 | 4,643 | (65) | | | | 4,708 | 3.45% | 4,546 | 62 | 153 | 153 | 3,983 | 16.50% | 3.84% | 20.34% |
| 2029 /30 | | 4,360 | (77) | (76) | 4,284 | 298 | 0.953 | 1.088 | 4,352 | 0 | 4,352 | 4,636 | (65) | | | | 4,701 | 3.46% | 4,538 | 55 | 131 | 131 | 4,001 | 16.50% | 3.27% | 19.77% |
| 2030 /31 | | 4,376 | (78) | (77) | 4,299 | 298 | 0.953 | 1.088 | 4,368 | 0 | 4,368 | 4,636 | 0 | | | | 4,636 | 3.46% | 4,476 | 55 | 52 | 53 | 4,015 | 16.50% | 1.32% | 17.82% |
| 2031 /32 | | 4,392 | (76) | (77) | 4,315 | 298 | 0.953 | 1.086 | 4,386 | 0 | 4,386 | 4,636 | 0 | | | | 4,636 | 3.46% | 4,476 | 55 | 34 | 35 | 4,030 | 16.50% | 0.87% | 17.37% |
| 2032 /33 | | 4,397 | (78) | (77) | 4,320 | 298 | 0.953 | 1.088 | 4,392 | 0 | 4,392 | 4,624 | 0 | | | | 4,624 | 3.47% | 4,464 | 42 | 29 | 30 | 4,036 | 16.50% | 0.74% | 17.24% |
| 2033 /34 | | 4,427 | (79) | (77) | 4,350 | 298 | 0.953 | 1.088 | 4,424 | 0 | 4,424 | 4,624 | 0 | | | | 4,624 | 3.47% | 4,464 | 42 | (3) | (2) | 4,063 | 16.50% | -0.05% | 16.45% |
| 2034 /35 | | 4,439 | (79) | (78) | 4,351 | 298 | 0.953 | 1.088 | 4,436 | 0 | 4,436 | 4,598 | 0 | | | | 4,598 | 3.49% | 4,438 | 16 | (15) | (14) | 4,073 | 16.50% | -0.34% | 16.16% |
| 2035 /36 | | 4,459 | (79) | (78) | 4,381 | 298 | 0.953 | 1.088 | 4,457 | 0 | 4,457 | 3,592 | 0 | | | | 3,592 | 3.67% | 3,460 | 16 | (1,013) | (1,013) | 4,091 | 16.50% | -24.76% | -8.26% |

Notes:
(a) Based on (June 2015) Load Forecast (with implied PJM diversity factor)

(b) Existing plus approved and projected "Passive" EE, and VVO
(note: these values & timing are for reference only and are not reflected in position determination)

(c) For PJM planning purposes, the ultimate impact of new DSM is 'delayed' ~4 years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process

(d) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR

(e) Installed Reserve Margin (IRM) = 16.4%(2016), 16.5%(2017-2035)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes company MLR share of any FRR view of obligations only

(g) Reflects the members ownership ratio of following summer capability assumptions:
I&M's share of AEP's OVEC capacity (43.47% PPR-share of full ~2,180 total capacity)
Assumes hydro units are derated to August average output in 2017/18
Wind Farm PPAs (Where Applicable)

(g) continued
**EFFICIENCY IMPROVEMENTS:**
2017/18: Cook 2: 50 MW (turbine)
2018/19: Rockport 1: 36 MW (turbine)
2020/21: Rockport 2: 36 MW (turbine)
**FGD DERATES:**
2025/26: Rockport 1: (18) MW
2028/29: Rockport 2: (18) MW
**RETIREMENTS:**
2015/16: Tanners Ck. 1-4
2035/36: Cook 1
2037/38: Cook 2

(h) Includes company's share of:
Estimated I&M nominations for PJM EE ('passive' DR program) levels
--reflected as a UCAP '<resource>'-- as part of PJM's emerging auction products (eff: 2014/15)

(i) New wind and solar capacity value is assumed to be 13% and 38% of nameplate

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity as of twelve months ended 9/30 of the previous year

(k) Represents yearly 'PJM- originated- forecast of AEP Zonal Load allocated to I&M and other AEP opcos based on 5CP

(l) Beginning with the 2020/21 PY, 'Base' UCAP levels will be reduced replaced (effectively reduced) in recognition of the full impact of PJM's "Capacity Performance" tariff. Such reductive impacts being largely anticipated for DR and intermittent (renewable) resources

Indiana Michigan Power Company
Attachment SCW-2

## Summary of Long-Term Commodity Price Forecast Scenarios Used in Plexos® Modeling

(Source AEP Fundamental Analysis, Mid-2015)

*Unless otherwise note, all Annual-Average pricing is represented in 'Nominal' Dollars*

### NATURAL GAS (@ Henry Hub)
($/MMBtu)

| | | *Alternative Scenarios* | | | |
|---|---|---|---|---|---|
| | 'BASE' Forecast | Higher Band | Lower Band | No $CO_2$ | High $CO_2$ |
| | Carbon in 2022 | Carbon in 2022 | Carbon in 2022 | | |
| 2016 | 4.34 | 4.94 | 3.73 | 4.34 | 4.34 |
| 2017 | 5.09 | 5.80 | 4.38 | 5.09 | 5.09 |
| 2018 | 5.40 | 6.16 | 4.64 | 5.40 | 5.40 |
| 2019 | 5.50 | 6.27 | 4.73 | 5.50 | 5.51 |
| 2020 | 5.60 | 6.39 | 4.82 | 5.61 | 5.61 |
| 2021 | 5.82 | 6.64 | 5.01 | 5.74 | 5.83 |
| 2022 | 6.28 | 7.16 | 5.40 | 5.88 | 6.37 |
| 2023 | 6.60 | 7.52 | 5.68 | 6.02 | 6.79 |
| 2024 | 6.80 | 7.75 | 5.85 | 6.16 | 7.01 |
| 2025 | 6.96 | 7.94 | 5.99 | 6.31 | 7.18 |
| 2026 | 7.13 | 8.13 | 6.13 | 6.46 | 7.35 |
| 2027 | 7.30 | 8.32 | 6.28 | 6.62 | 7.53 |
| 2028 | 7.47 | 8.52 | 6.43 | 6.77 | 7.71 |
| 2029 | 7.65 | 8.73 | 6.58 | 6.94 | 7.90 |
| 2030 | 7.83 | 8.92 | 6.73 | 7.09 | 8.07 |
| 2031 | 8.00 | 9.12 | 6.88 | 7.25 | 8.25 |
| 2032 | 8.19 | 9.34 | 7.04 | 7.42 | 8.45 |
| 2033 | 8.39 | 9.57 | 7.22 | 7.60 | 8.66 |
| 2034 | 8.59 | 9.79 | 7.39 | 7.79 | 8.86 |
| 2035 | 8.80 | 10.04 | 7.57 | 7.98 | 9.08 |
| 2036 | 9.02 | 10.29 | 7.76 | 8.18 | 9.31 |
| 2037 | 9.24 | 10.53 | 7.94 | 8.37 | 9.53 |
| 2038 | 9.45 | 10.77 | 8.12 | 8.56 | 9.74 |
| 2039 | 9.66 | 11.01 | 8.31 | 8.76 | 9.96 |
| 2040 | 9.87 | 11.25 | 8.49 | 8.95 | 10.18 |
| 2041 | 10.08 | 11.49 | 8.67 | 9.14 | 10.40 |
| 2042 | 10.29 | 11.73 | 8.85 | 9.33 | 10.62 |
| 2043 | 10.50 | 11.97 | 9.03 | 9.52 | 10.83 |
| 2044 | 10.71 | 12.21 | 9.21 | 9.71 | 11.05 |
| 2045 | 10.92 | 12.45 | 9.39 | 9.90 | 11.26 |

### CO2
($/Metric Tonne)

| | | *Alternative Scenarios* | | | |
|---|---|---|---|---|---|
| | 'BASE' Forecast | Higher Band | Lower Band | No $CO_2$ | High $CO_2$ |
| | Carbon in 2022 | Carbon in 2022 | Carbon in 2022 | | Carbon in 2022 |
| 2016 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 15.00 | 15.00 | 15.00 | 0.00 | 25.00 |
| 2023 | 15.29 | 15.29 | 15.29 | 0.00 | 25.47 |
| 2024 | 15.58 | 15.58 | 15.58 | 0.00 | 25.96 |
| 2025 | 15.88 | 15.88 | 15.88 | 0.00 | 26.47 |
| 2026 | 16.19 | 16.19 | 16.19 | 0.00 | 27.00 |
| 2027 | 16.51 | 16.51 | 16.51 | 0.00 | 27.52 |
| 2028 | 16.84 | 16.84 | 16.84 | 0.00 | 28.08 |
| 2029 | 17.17 | 17.17 | 17.17 | 0.00 | 28.62 |
| 2030 | 17.50 | 17.50 | 17.50 | 0.00 | 29.18 |
| 2031 | 17.85 | 17.85 | 17.85 | 0.00 | 29.74 |
| 2032 | 18.19 | 18.19 | 18.19 | 0.00 | 30.31 |
| 2033 | 18.54 | 18.54 | 18.54 | 0.00 | 30.90 |
| 2034 | 18.88 | 18.88 | 18.88 | 0.00 | 31.48 |
| 2035 | 19.24 | 19.24 | 19.24 | 0.00 | 32.07 |
| 2036 | 19.60 | 19.60 | 19.60 | 0.00 | 32.66 |
| 2037 | 19.95 | 19.95 | 19.95 | 0.00 | 33.26 |
| 2038 | 20.33 | 20.33 | 20.33 | 0.00 | 33.87 |
| 2039 | 20.69 | 20.69 | 20.69 | 0.00 | 34.49 |
| 2040 | 21.08 | 21.08 | 21.08 | 0.00 | 35.12 |
| 2041 | 21.46 | 21.46 | 21.46 | 0.00 | 35.77 |
| 2042 | 21.86 | 21.86 | 21.86 | 0.00 | 36.42 |
| 2043 | 22.26 | 22.26 | 22.26 | 0.00 | 37.09 |
| 2044 | 22.66 | 22.66 | 22.66 | 0.00 | 37.78 |
| 2045 | 23.08 | 23.08 | 23.08 | 0.00 | 38.47 |

### Coal-Illinois Basin (~4.3#)
($/Ton-FOB Mine)

| | | *Alternative Scenarios* | | | |
|---|---|---|---|---|---|
| | 'BASE' Forecast | Higher Band | Lower Band | No $CO_2$ | High $CO_2$ |
| | Carbon in 2022 | Carbon in 2022 | Carbon in 2022 | | Carbon in 2022 |
| 2016 | 40.00 | 40.00 | 40.00 | 40.00 | 40.00 |
| 2017 | 42.25 | 44.36 | 40.56 | 42.25 | 42.25 |
| 2018 | 43.56 | 47.91 | 40.07 | 43.56 | 43.56 |
| 2019 | 45.92 | 52.80 | 40.41 | 45.92 | 45.92 |
| 2020 | 48.60 | 55.90 | 42.77 | 47.78 | 48.60 |
| 2021 | 50.19 | 57.72 | 44.17 | 49.72 | 50.19 |
| 2022 | 53.49 | 61.51 | 47.07 | 51.74 | 53.49 |
| 2023 | 51.01 | 58.67 | 44.89 | 53.84 | 51.01 |
| 2024 | 55.88 | 64.26 | 49.18 | 56.03 | 55.88 |
| 2025 | 56.30 | 64.75 | 49.55 | 58.30 | 56.30 |
| 2026 | 57.53 | 66.16 | 50.63 | 59.57 | 57.53 |
| 2027 | 57.91 | 66.59 | 50.96 | 59.96 | 57.91 |
| 2028 | 59.93 | 68.92 | 52.74 | 62.06 | 59.93 |
| 2029 | 64.10 | 73.71 | 56.41 | 66.37 | 64.10 |
| 2030 | 65.72 | 75.58 | 57.84 | 68.05 | 65.72 |
| 2031 | 68.05 | 78.26 | 59.89 | 70.47 | 68.05 |
| 2032 | 69.56 | 80.00 | 61.21 | 72.03 | 69.56 |
| 2033 | 74.69 | 85.89 | 65.73 | 77.34 | 74.69 |
| 2034 | 78.16 | 89.89 | 68.78 | 80.93 | 78.16 |
| 2035 | 80.24 | 92.27 | 70.61 | 83.08 | 80.24 |
| 2036 | 82.24 | 94.58 | 72.37 | 85.16 | 82.24 |
| 2037 | 84.30 | 96.94 | 74.18 | 87.29 | 84.30 |
| 2038 | 86.41 | 99.37 | 76.04 | 89.47 | 86.41 |
| 2039 | 88.57 | 101.85 | 77.94 | 91.71 | 88.57 |
| 2040 | 90.78 | 104.40 | 79.89 | 94.00 | 90.78 |
| 2041 | 93.05 | 107.01 | 81.88 | 96.35 | 93.05 |
| 2042 | 95.38 | 109.68 | 83.93 | 98.76 | 95.38 |
| 2043 | 97.28 | 111.88 | 85.61 | 100.73 | 97.28 |
| 2044 | 99.23 | 114.11 | 87.32 | 102.75 | 99.23 |
| 2045 | 101.21 | 116.40 | 89.07 | 104.80 | 101.21 |

### Coal-PRB (~0.8#, 8400 Btu)
($/Ton-FOB Mine)

| | | *Alternative Scenarios* | | | |
|---|---|---|---|---|---|
| | 'BASE' Forecast | Higher Band | Lower Band | No $CO_2$ | High $CO_2$ |
| | Carbon in 2022 | Carbon in 2022 | Carbon in 2022 | | Carbon in 2022 |
| 2016 | 11.50 | 11.50 | 11.50 | 11.50 | 11.50 |
| 2017 | 12.30 | 12.91 | 11.81 | 12.30 | 12.30 |
| 2018 | 13.56 | 14.92 | 12.48 | 13.56 | 13.56 |
| 2019 | 14.74 | 16.95 | 12.97 | 14.74 | 14.74 |
| 2020 | 16.80 | 19.32 | 14.78 | 15.47 | 16.80 |
| 2021 | 17.97 | 20.67 | 15.81 | 16.24 | 17.97 |
| 2022 | 18.47 | 21.24 | 16.25 | 17.05 | 18.47 |
| 2023 | 16.88 | 19.41 | 14.85 | 17.90 | 16.88 |
| 2024 | 17.60 | 20.24 | 15.49 | 18.79 | 17.60 |
| 2025 | 18.91 | 21.75 | 16.64 | 19.72 | 18.91 |
| 2026 | 21.26 | 24.45 | 18.71 | 22.17 | 21.26 |
| 2027 | 20.19 | 23.22 | 17.77 | 21.05 | 20.19 |
| 2028 | 20.73 | 23.84 | 18.24 | 21.62 | 20.73 |
| 2029 | 24.40 | 28.06 | 21.47 | 25.44 | 24.40 |
| 2030 | 23.52 | 27.05 | 20.70 | 24.53 | 23.52 |
| 2031 | 26.64 | 30.64 | 23.44 | 27.78 | 26.64 |
| 2032 | 27.87 | 32.05 | 24.53 | 29.06 | 27.87 |
| 2033 | 30.21 | 34.74 | 26.58 | 31.50 | 30.21 |
| 2034 | 32.02 | 36.82 | 28.18 | 33.39 | 32.02 |
| 2035 | 36.36 | 41.81 | 32.00 | 37.92 | 36.36 |
| 2036 | 37.27 | 42.86 | 32.80 | 38.86 | 37.27 |
| 2037 | 38.20 | 43.93 | 33.62 | 39.84 | 38.20 |
| 2038 | 39.16 | 45.03 | 34.46 | 40.83 | 39.16 |
| 2039 | 40.13 | 46.15 | 35.32 | 41.85 | 40.13 |
| 2040 | 41.14 | 47.31 | 36.20 | 42.90 | 41.14 |
| 2041 | 42.17 | 48.49 | 37.11 | 43.97 | 42.17 |
| 2042 | 43.22 | 49.70 | 38.03 | 45.07 | 43.22 |
| 2043 | 44.09 | 50.70 | 38.79 | 45.97 | 44.09 |
| 2044 | 44.97 | 51.71 | 39.57 | 46.89 | 44.97 |
| 2045 | 45.87 | 52.75 | 40.36 | 47.83 | 45.87 |

### NATURAL GAS (@ Henry Hub) (REAL, 2014 $)
($/MMBtu)

| | | *Alternative Scenarios* | | | |
|---|---|---|---|---|---|
| | 'BASE' Forecast | Higher Band | Lower Band | No $CO_2$ | High $CO_2$ |
| | Carbon in 2022 | Carbon in 2022 | Carbon in 2022 | | |
| 2016 | 4.24 | 4.83 | 3.64 | 4.24 | 4.24 |
| 2017 | 4.85 | 5.53 | 4.17 | 4.85 | 4.86 |
| 2018 | 5.02 | 5.72 | 4.32 | 5.02 | 5.02 |
| 2019 | 4.98 | 5.68 | 4.28 | 4.98 | 4.98 |
| 2020 | 4.94 | 5.64 | 4.25 | 4.95 | 4.95 |
| 2021 | 5.02 | 5.72 | 4.32 | 4.95 | 5.02 |
| 2022 | 5.30 | 6.04 | 4.56 | 4.96 | 5.37 |
| 2023 | 5.45 | 6.21 | 4.68 | 4.97 | 5.61 |
| 2024 | 5.50 | 6.27 | 4.73 | 4.98 | 5.67 |
| 2025 | 5.51 | 6.29 | 4.74 | 5.00 | 5.69 |
| 2026 | 5.53 | 6.30 | 4.75 | 5.01 | 5.70 |
| 2027 | 5.55 | 6.33 | 4.77 | 5.03 | 5.72 |
| 2028 | 5.57 | 6.35 | 4.79 | 5.05 | 5.75 |
| 2029 | 5.59 | 6.38 | 4.81 | 5.07 | 5.77 |
| 2030 | 5.61 | 6.39 | 4.82 | 5.08 | 5.78 |
| 2031 | 5.62 | 6.41 | 4.83 | 5.10 | 5.80 |
| 2032 | 5.64 | 6.43 | 4.85 | 5.11 | 5.82 |
| 2033 | 5.67 | 6.46 | 4.87 | 5.13 | 5.84 |
| 2034 | 5.69 | 6.49 | 4.90 | 5.16 | 5.87 |
| 2035 | 5.72 | 6.53 | 4.92 | 5.19 | 5.90 |
| 2036 | 5.75 | 6.56 | 4.95 | 5.22 | 5.93 |
| 2037 | 5.77 | 6.58 | 4.96 | 5.23 | 5.95 |
| 2038 | 5.79 | 6.60 | 4.98 | 5.25 | 5.97 |
| 2039 | 5.81 | 6.62 | 5.00 | 5.26 | 5.99 |
| 2040 | 5.83 | 6.64 | 5.01 | 5.28 | 6.01 |
| 2041 | 5.84 | 6.66 | 5.02 | 5.29 | 6.02 |
| 2042 | 5.85 | 6.67 | 5.03 | 5.30 | 6.03 |
| 2043 | 5.86 | 6.68 | 5.04 | 5.31 | 6.04 |
| 2044 | 5.87 | 6.69 | 5.05 | 5.32 | 6.05 |
| 2045 | 5.88 | 6.70 | 5.05 | 5.33 | 6.06 |

### ON-Peak Energy (PJM-AEP Gen Hub)
($/Mwh)

| | | *Alternative Scenarios* | | | |
|---|---|---|---|---|---|
| | 'BASE' Forecast | Higher Band | Lower Band | No $CO_2$ | High $CO_2$ |
| | Carbon in 2022 | Carbon in 2022 | Carbon in 2022 | | Carbon in 2022 |
| 2016 | 35.34 | 37.02 | 33.47 | 35.45 | 35.93 |
| 2017 | 38.62 | 41.40 | 35.80 | 38.49 | 39.45 |
| 2018 | 40.37 | 44.71 | 36.56 | 39.91 | 41.13 |
| 2019 | 43.12 | 48.95 | 37.70 | 42.30 | 43.12 |
| 2020 | 44.97 | 50.62 | 39.24 | 43.72 | 44.14 |
| 2021 | 47.42 | 52.75 | 40.84 | 45.72 | 46.01 |
| 2022 | 62.04 | 68.03 | 54.53 | 47.48 | 66.45 |
| 2023 | 63.73 | 69.91 | 56.08 | 49.57 | 69.17 |
| 2024 | 66.89 | 73.74 | 58.81 | 52.11 | 71.74 |
| 2025 | 69.81 | 77.14 | 60.84 | 54.34 | 74.58 |
| 2026 | 72.39 | 79.74 | 62.57 | 56.19 | 76.58 |
| 2027 | 75.10 | 82.49 | 64.71 | 58.43 | 79.27 |
| 2028 | 77.21 | 85.22 | 67.04 | 61.04 | 81.56 |
| 2029 | 79.93 | 88.24 | 69.38 | 63.63 | 84.65 |
| 2030 | 82.57 | 91.07 | 72.16 | 66.79 | 87.57 |
| 2031 | 85.39 | 94.01 | 74.58 | 69.70 | 89.71 |
| 2032 | 88.74 | 96.88 | 77.29 | 72.60 | 92.88 |
| 2033 | 92.42 | 100.73 | 81.63 | 76.23 | 97.06 |
| 2034 | 93.33 | 103.51 | 84.22 | 78.19 | 98.26 |
| 2035 | 95.81 | 106.38 | 86.73 | 80.93 | 101.15 |
| 2036 | 99.04 | 108.87 | 88.52 | 83.67 | 103.17 |
| 2037 | 101.38 | 110.81 | 91.21 | 86.05 | 104.99 |
| 2038 | 104.70 | 115.45 | 94.18 | 89.79 | 107.76 |
| 2039 | 105.73 | 116.69 | 95.57 | 91.41 | 109.34 |
| 2040 | 108.64 | 118.55 | 98.11 | 95.19 | 112.11 |
| 2041 | 110.08 | 121.38 | 100.11 | 97.49 | 114.81 |
| 2042 | 112.43 | 123.40 | 100.64 | 98.76 | 115.24 |
| 2043 | 114.44 | 126.23 | 102.99 | 101.74 | 118.35 |
| 2044 | 115.92 | 127.70 | 104.53 | 103.79 | 120.12 |
| 2045 | 119.58 | 129.97 | 106.94 | 105.53 | 123.70 |

### OFF-Peak Energy (PJM-AEP Gen Hub)
($/Mwh)

| | | *Alternative Scenarios* | | | |
|---|---|---|---|---|---|
| | 'BASE' Forecast | Higher Band | Lower Band | No $CO_2$ | High $CO_2$ |
| | Carbon in 2022 | Carbon in 2022 | Carbon in 2022 | | Carbon in 2022 |
| 2016 | 26.65 | 27.17 | 26.19 | 26.63 | 25.73 |
| 2017 | 27.41 | 28.79 | 26.18 | 27.26 | 26.70 |
| 2018 | 28.22 | 30.89 | 25.94 | 27.71 | 27.37 |
| 2019 | 30.31 | 34.41 | 26.61 | 29.57 | 29.02 |
| 2020 | 32.05 | 36.23 | 28.08 | 30.61 | 29.94 |
| 2021 | 33.59 | 37.38 | 29.17 | 32.18 | 30.93 |
| 2022 | 47.94 | 51.96 | 43.25 | 33.74 | 52.16 |
| 2023 | 48.59 | 52.59 | 43.74 | 34.98 | 53.96 |
| 2024 | 50.93 | 55.45 | 45.63 | 36.98 | 55.70 |
| 2025 | 52.82 | 57.68 | 46.98 | 38.41 | 57.63 |
| 2026 | 54.98 | 60.02 | 48.49 | 40.13 | 59.55 |
| 2027 | 56.64 | 61.85 | 49.73 | 41.52 | 61.39 |
| 2028 | 58.27 | 63.80 | 51.00 | 43.20 | 62.86 |
| 2029 | 60.58 | 66.52 | 53.09 | 45.56 | 65.28 |
| 2030 | 62.38 | 68.60 | 54.88 | 47.58 | 67.30 |
| 2031 | 64.62 | 71.02 | 56.52 | 49.61 | 68.78 |
| 2032 | 66.97 | 73.38 | 58.39 | 51.79 | 71.55 |
| 2033 | 70.20 | 77.00 | 61.53 | 54.81 | 74.49 |
| 2034 | 71.58 | 79.59 | 63.39 | 56.44 | 75.76 |
| 2035 | 74.02 | 82.26 | 65.20 | 58.92 | 78.21 |
| 2036 | 76.49 | 84.53 | 66.78 | 60.70 | 79.73 |
| 2037 | 78.90 | 86.57 | 69.07 | 63.12 | 81.71 |
| 2038 | 81.50 | 90.72 | 71.48 | 66.45 | 84.39 |
| 2039 | 83.17 | 92.47 | 73.26 | 68.41 | 86.27 |
| 2040 | 85.64 | 94.61 | 75.41 | 71.16 | 88.75 |
| 2041 | 87.49 | 97.31 | 77.21 | 73.57 | 91.03 |
| 2042 | 89.33 | 99.27 | 78.30 | 75.28 | 92.14 |
| 2043 | 91.67 | 102.03 | 80.48 | 78.38 | 94.81 |
| 2044 | 93.50 | 103.75 | 82.15 | 80.51 | 96.68 |
| 2045 | 96.27 | 105.83 | 84.05 | 82.53 | 99.74 |

### Capacity Value (PJM-RTO RPM)
($/MW-Day)

| | | *Alternative Scenarios* | | | |
|---|---|---|---|---|---|
| | 'BASE' Forecast | Higher Band | Lower Band | No $CO_2$ | High $CO_2$ |
| | Carbon in 2022 | Carbon in 2022 | Carbon in 2022 | | Carbon in 2022 |
| 2016 | 91.30 | 91.30 | 91.30 | 91.30 | 91.30 |
| 2017 | 94.74 | 94.74 | 94.74 | 94.74 | 94.74 |
| 2018 | 187.37 | 225.68 | 225.68 | 225.68 | 171.28 |
| 2019 | 260.32 | 309.31 | 309.31 | 309.31 | 238.84 |
| 2020 | 287.24 | 317.35 | 317.35 | 317.35 | 276.25 |
| 2021 | 314.48 | 324.65 | 324.65 | 324.65 | 316.66 |
| 2022 | 331.79 | 331.79 | 331.79 | 331.79 | 331.79 |
| 2023 | 339.09 | 339.09 | 339.09 | 339.09 | 339.09 |
| 2024 | 346.21 | 346.21 | 346.21 | 346.21 | 346.21 |
| 2025 | 353.48 | 353.48 | 353.48 | 353.48 | 353.48 |
| 2026 | 360.90 | 360.90 | 360.90 | 360.90 | 360.90 |
| 2027 | 368.12 | 368.12 | 368.12 | 368.12 | 368.12 |
| 2028 | 375.48 | 375.48 | 375.48 | 375.48 | 375.48 |
| 2029 | 382.99 | 382.99 | 382.99 | 382.99 | 382.99 |
| 2030 | 390.65 | 390.65 | 390.65 | 390.65 | 390.65 |
| 2031 | 398.47 | 398.47 | 398.47 | 398.47 | 398.47 |
| 2032 | 406.44 | 406.44 | 406.44 | 406.44 | 406.44 |
| 2033 | 414.56 | 414.56 | 414.56 | 414.56 | 414.56 |
| 2034 | 422.44 | 422.44 | 422.44 | 422.44 | 422.44 |
| 2035 | 430.47 | 430.47 | 430.47 | 430.47 | 430.47 |
| 2036 | 439.08 | 439.08 | 439.08 | 439.08 | 439.08 |
| 2037 | 447.86 | 447.86 | 447.86 | 447.86 | 447.86 |
| 2038 | 456.81 | 456.81 | 456.81 | 456.81 | 456.81 |
| 2039 | 465.95 | 465.95 | 465.95 | 465.95 | 465.95 |
| 2040 | 475.27 | 475.27 | 475.27 | 475.27 | 475.27 |
| 2041 | 484.78 | 484.78 | 484.78 | 484.78 | 484.78 |
| 2042 | 494.47 | 494.47 | 494.47 | 494.47 | 494.47 |
| 2043 | 504.36 | 504.36 | 504.36 | 504.36 | 504.36 |
| 2044 | 514.45 | 514.45 | 514.45 | 514.45 | 514.45 |
| 2045 | 524.74 | 524.74 | 524.74 | 524.74 | 524.74 |

* Represents actual cleared forward PJM-RTO Base Residual Auction UCAP clearing prices for those respective XXXX/(XXXX 1) forward PJM Planning Years (represented on a wtd "calendar year" basis).

# Summary of Major Cost & Performance Paramenters <u>Used in Modeling</u>

*(All Cost Estimates reflected in 'Nominal' $)*

***Rockport Unit 1...***

| | Rockport U1 (Total Unit -- initially, 1315 MW) | | | | | | | | | | | | | Rockport U1 (I&M Cost-Based Share [@85%]) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | *Performance Parameter* | | | | | | | *Cost Parameter* | | | | | | | | | | | |
| | | | | | | | | | Consumables | | | | | ($000) | | | | | |
| | Unit Capability | | Heat Rate | Avg. | Emission Rates | | | Delivered | Sodium | Activated | Anhydrous | Lime | Other | FOM | | | On-Going Capital* | | |
| | Max | Min | -Avg Annual- | Availability | $SO_2$ | $NO_x$ | Hg | Fuel Cost | Bicarb (DSI) | Carbon (ACI) | Ammonia (SCR) | (DFGD) | VOM | *If U2 NOT* | *If U2 Returned* | *If U2 Returned* | *If U2 NOT* | *If U2 Returned* | *If U2 Returned* |
| | (MW) | (MW) | (Btu/kWh) | (%) | (lb/MMBtu) | (lb/MMBtu) | (lb/Trillion Btu) | ($/MMBtu) | ($/MMBtu) | ($/MMBtu) | ($/MMBtu) | ($/MMBtu) | ($/Mwh) | Returned | Dec-19 | Dec-22 | Returned | Dec-19 | Dec-22 |
| 2016 | 1,315 | 500 | [redacted] | | | | | | | | | | 1.01 | 9,005 | 9,005 | 9,005 | 26,627 | 26,627 | 26,627 |
| 2017 | 1,315 | 500 | | | | | | | | | | | 1.03 | 17,022 | 17,022 | 17,022 | 34,572 | 34,572 | 34,572 |
| 2018 RK1 SCR | 1,351 | 651 | | | | | | | | | | | 1.05 | 9,648 | 9,648 | 9,648 | 15,192 | 15,192 | 15,192 |
| 2019 | 1,351 | 651 | | | | | | | | | | | 1.07 | 9,154 | 9,154 | 9,154 | 34,128 | 34,128 | 34,128 |
| 2020 | 1,351 | 651 | | | | | | | | | | | 1.08 | 18,291 | 25,589 | 18,291 | 49,829 | 76,708 | 49,829 |
| 2021 | 1,351 | 651 | | | | | | | | | | | 1.10 | 9,480 | 16,898 | 9,480 | 38,508 | 53,181 | 38,508 |
| 2022 | 1,351 | 651 | | | | | | | | | | | 1.12 | 16,828 | 24,391 | 16,828 | 17,530 | 23,234 | 17,530 |
| 2023 | 1,351 | 651 | | | | | | | | | | | 1.14 | 10,055 | 17,749 | 17,749 | 7,244 | 10,408 | 10,408 |
| 2024 | 1,351 | 651 | | | | | | | | | | | 1.17 | 17,958 | 25,791 | 25,791 | 5,779 | 8,895 | 8,895 |
| 2025 | 1,351 | 651 | | | | | | | | | | | 1.19 | 9,643 | 17,171 | 17,171 | 2,104 | 2,963 | 2,963 |
| 2026 RK1 DFGD | 1,333 | 651 | | | | | | | | | | | 1.21 | 12,374 | 20,416 | 20,416 | 24,520 | 24,520 | 24,520 |
| 2027 | 1,333 | 651 | | | | | | | | | | | 1.24 | 11,516 | 19,683 | 19,683 | 25,133 | 25,133 | 25,133 |
| 2028 | 1,333 | 651 | | | | | | | | | | | 1.26 | 12,840 | 21,132 | 21,132 | 25,761 | 25,761 | 25,761 |
| 2029 | 1,333 | 651 | | | | | | | | | | | 1.28 | 11,144 | 19,557 | 19,557 | 26,405 | 26,405 | 26,405 |
| 2030 | 1,333 | 651 | | | | | | | | | | | 1.31 | 12,908 | 21,553 | 21,553 | 27,065 | 27,065 | 27,065 |
| 2031 | 1,333 | 651 | | | | | | | | | | | 1.33 | 12,648 | 21,452 | 21,452 | 27,742 | 27,742 | 27,742 |
| 2032 | 1,333 | 651 | | | | | | | | | | | 1.36 | 12,228 | 21,198 | 21,198 | 28,435 | 28,435 | 28,435 |
| 2033 | 1,333 | 651 | | | | | | | | | | | 1.38 | 13,817 | 22,966 | 22,966 | 29,146 | 29,146 | 29,146 |
| 2034 | 1,333 | 651 | | | | | | | | | | | 1.41 | 12,787 | 22,129 | 22,129 | 29,875 | 29,875 | 29,875 |
| 2035 | 1,333 | 651 | | | | | | | | | | | 1.43 | 13,665 | 23,190 | 23,190 | 30,622 | 30,622 | 30,622 |
| 2036 | 1,333 | 651 | | | | | | | | | | | 1.46 | 13,285 | 23,000 | 23,000 | 31,387 | 31,387 | 31,387 |
| 2037 | 1,333 | 651 | | | | | | | | | | | 1.48 | 15,193 | 25,103 | 25,103 | 32,172 | 32,172 | 32,172 |
| 2038 | 1,333 | 651 | | | | | | | | | | | 1.51 | 13,733 | 23,843 | 23,843 | 32,976 | 32,976 | 32,976 |
| 2039 | 1,333 | 651 | | | | | | | | | | | 1.54 | 14,977 | 25,289 | 25,289 | 33,801 | 33,801 | 33,801 |
| 2040 | 1,333 | 651 | | | | | | | | | | | 1.56 | 14,531 | 25,050 | 25,050 | 32,111 | 32,111 | 32,111 |
| 2041 | 1,333 | 651 | | | | | | | | | | | 1.59 | 15,781 | 26,511 | 26,511 | 30,505 | 30,505 | 30,505 |
| 2042 | 1,333 | 651 | | | | | | | | | | | 1.62 | 14,803 | 25,748 | 25,748 | 28,980 | 28,980 | 28,980 |
| 2043 | 1,333 | 651 | | | | | | | | | | | 1.64 | 16,373 | 27,537 | 27,537 | 27,531 | 27,531 | 27,531 |
| 2044 | 1,333 | 651 | | | | | | | | | | | 1.67 | 15,706 | 27,095 | 27,095 | 26,154 | 26,154 | 26,154 |
| 2045 | 1,333 | 651 | | | | | | | | | | | 1.70 | 17,727 | 29,344 | 29,344 | 24,847 | 24,847 | 24,847 |

***Rockport Unit 2...***

| | Rockport U2 (Total Unit -- initially, 1300 MW) | | | | | | | | | | | | | Rockport U2 (I&M Cost-Based Share [@85%]) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | *Performance Parameter* | | | | | | | *Cost Parameter* | | | | | | | | | | | |
| | | | | | | | | | Consumables | | | | | ($000) | | | | | |
| | Unit Capability | | Heat Rate | Avg. | Emission Rates | | | Delivered | Sodium | Activated | Anhydrous | Lime | Other | FOM | | | On-Going Capital* | | |
| | Max | Min | -Avg Annual- | Availability | $SO_2$ | $NO_x$ | Hg | Fuel Cost | Bicarb (DSI) | Carbon (ACI) | Ammonia (SCR) | (DFGD) | VOM | *If U2 NOT* | *If U2 Returned* | *If U2 Returned* | *If U2 NOT* | *If U2 Returned* | *If U2 Returned* |
| | (MW) | (MW) | (Btu/kWh) | (%) | (lb./MMBtu) | (lb./MMBtu) | (lb/Trillion Btu) | ($/MMBtu) | ($/MMBtu) | ($/MMBtu) | ($/MMBtu) | ($/MMBtu) | ($/Mwh) | Returned | Dec-19 | Dec-22 | Returned | Dec-19 | Dec-22 |
| 2016 | 1,300 | 500 | [redacted] | | | | | | | | | | 0.99 | 9,118 | 9,118 | 9,118 | 6,384 | 4,788 | 6,384 |
| 2017 | 1,300 | 500 | | | | | | | | | | | 1.01 | 9,101 | 9,101 | 9,101 | 12,036 | 3,975 | 5,963 |
| 2018 | 1,300 | 651 | | | | | | | | | | | 1.03 | 18,609 | 18,609 | 18,609 | 35,417 | 5,371 | 10,743 |
| 2019 | 1,300 | 651 | | | | | | | | | | | 1.04 | 18,665 | 18,665 | 18,665 | 46,295 | 0 | 9,400 |
| 2020 RK2 SCR | 1,336 | 651 | | | | | | | | | | | 1.06 | 10,202 | - | 10,202 | 27,872 | - | 2,787 |
| 2021 | 1,336 | 651 | | | | | | | | | | | 1.08 | 17,605 | - | 17,605 | 22,943 | - | 2,294 |
| 2022 | 1,336 | 651 | | | | | | | | | | | 1.10 | 10,989 | - | 10,989 | 29,987 | - | 0 |
| 2023 | 1,336 | 651 | | | | | | | | | | | 1.12 | 18,109 | - | - | 58,104 | - | - |
| 2024 | 1,336 | 651 | | | | | | | | | | | 1.14 | 11,114 | - | - | 9,309 | - | - |
| 2025 | 1,336 | 651 | | | | | | | | | | | 1.16 | 7,852 | - | - | 10,534 | - | - |
| 2026 | 1,336 | 651 | | | | | | | | | | | 1.19 | 10,792 | - | - | 24,520 | - | - |
| 2027 | 1,336 | 651 | | | | | | | | | | | 1.21 | 11,384 | - | - | 25,133 | - | - |
| 2028 | 1,336 | 651 | | | | | | | | | | | 1.23 | 12,217 | - | - | 25,761 | - | - |
| 2029 RK2 DFGD | 1,318 | 651 | | | | | | | | | | | 1.25 | 10,069 | - | - | 26,405 | - | - |
| 2030 | 1,318 | 651 | | | | | | | | | | | 1.28 | 11,409 | - | - | 27,065 | - | - |
| 2031 | 1,318 | 651 | | | | | | | | | | | 1.30 | 11,139 | - | - | 27,742 | - | - |
| 2032 | 1,318 | 651 | | | | | | | | | | | 1.33 | 11,815 | - | - | 28,435 | - | - |
| 2033 | 1,318 | 651 | | | | | | | | | | | 1.35 | 11,029 | - | - | 29,146 | - | - |
| 2034 | 1,318 | 651 | | | | | | | | | | | 1.38 | 12,095 | - | - | 29,875 | - | - |
| 2035 | 1,318 | 651 | | | | | | | | | | | 1.40 | 11,711 | - | - | 30,622 | - | - |
| 2036 | 1,318 | 651 | | | | | | | | | | | 1.43 | 12,823 | - | - | 31,387 | - | - |
| 2037 | 1,318 | 651 | | | | | | | | | | | 1.45 | 12,044 | - | - | 32,172 | - | - |
| 2038 | 1,318 | 651 | | | | | | | | | | | 1.48 | 13,523 | - | - | 32,976 | - | - |
| 2039 | 1,318 | 651 | | | | | | | | | | | 1.50 | 12,513 | - | - | 33,801 | - | - |
| 2040 | 1,318 | 651 | | | | | | | | | | | 1.53 | 13,566 | - | - | 32,111 | - | - |
| 2041 | 1,318 | 651 | | | | | | | | | | | 1.55 | 12,932 | - | - | 30,505 | - | - |
| 2042 | 1,318 | 651 | | | | | | | | | | | 1.58 | 14,529 | - | - | 28,980 | - | - |
| 2043 | 1,318 | 651 | | | | | | | | | | | 1.61 | 13,652 | - | - | 27,531 | - | - |
| 2044 | 1,318 | 651 | | | | | | | | | | | 1.64 | 14,971 | - | - | 26,154 | - | - |
| 2045 | 1,318 | 651 | | | | | | | | | | | 1.66 | 13,926 | - | - | 24,847 | - | - |

* Rockport unit 'On-Going Capital (OGC)' <u>excludes</u> both U1 & U2 SCR and (future) U1 & U2 DFGD major environmental capital expenditures highlighted on Weaver Direct Testimony, 'Table 3'

## Summary of Major Cost & Performance Paramenters Used in Modeling

*(All Cost Estimates reflected in 'Nominal' $)*

***New-Build Natural Gas Alternatives...***

**New-Build CC ("1/2 Block" of a 780 MW [870 MW w/ evap cooling], Mitsubishi 501GAC 2x2x1)**

| *Available In-Svc* | Capability* Max(Sum) (w Evap Cooling) | Capability* Nominal | Capability* Min | Avg. Avail. | (Nominal) Heat Rate -Avg Annual- | Fuel Cost @ 'TCO Pool' ** | VOM | FOM | On-Going Capital*** |
|---|---|---|---|---|---|---|---|---|---|
| *Years* | (MW) | (MW) | (MW) | (%) | (Btu/kWh) | ($/MMBtu) | ($/Mwh) | ($/kW-Yr) | ($/kW-Yr) |
| 2016 | - | - | - | - | - | - | - | - | - |
| 2017 | - | - | - | - | - | - | - | - | - |
| 2018 | - | - | - | - | - | - | - | - | - |
| 2019 | - | - | - | - | - | - | - | - | - |
| 2020 Opt 2 | 435 | 390 | 95 | [redacted] | | | $ 3.09 | $ 12.32 | - |
| 2021 | 435 | 390 | 95 | [redacted] | | | $ 3.15 | $ 12.57 | - |
| 2022 | 435 | 390 | 95 | [redacted] | | | $ 3.22 | $ 12.82 | - |
| 2023 Opt 1B | 435 | 390 | 95 | [redacted] | | | $ 3.28 | $ 13.08 | - |
| 2024 | 435 | 390 | 95 | [redacted] | | | $ 3.35 | $ 13.34 | - |
| 2025 | 435 | 390 | 95 | [redacted] | | | $ 3.41 | $ 13.60 | - |
| 2026 | 435 | 390 | 95 | [redacted] | | | $ 3.48 | $ 13.88 | - |
| 2027 | 435 | 390 | 95 | [redacted] | | | $ 3.55 | $ 14.15 | - |
| 2028 | 435 | 390 | 95 | [redacted] | | | $ 3.62 | $ 14.44 | - |
| 2029 | 435 | 390 | 95 | [redacted] | | | $ 3.69 | $ 14.73 | - |
| 2030 | 435 | 390 | 95 | [redacted] | | | $ 3.77 | $ 15.02 | - |
| 2031 | 435 | 390 | 95 | [redacted] | | | $ 3.84 | $ 15.32 | - |
| 2032 | 435 | 390 | 95 | [redacted] | | | $ 3.92 | $ 15.63 | - |
| 2033 | 435 | 390 | 95 | [redacted] | | | $ 4.00 | $ 15.94 | - |
| 2034 | 435 | 390 | 95 | [redacted] | | | $ 4.08 | $ 16.26 | - |
| 2035 | 435 | 390 | 95 | [redacted] | | | $ 4.16 | $ 16.58 | - |
| 2036 | 435 | 390 | 95 | [redacted] | | | $ 4.24 | $ 16.91 | - |
| 2037 | 435 | 390 | 95 | [redacted] | | | $ 4.33 | $ 17.25 | - |
| 2038 | 435 | 390 | 95 | [redacted] | | | $ 4.42 | $ 17.60 | - |
| 2039 | 435 | 390 | 95 | [redacted] | | | $ 4.50 | $ 17.95 | - |
| 2040 | 435 | 390 | 95 | [redacted] | | | $ 4.59 | $ 18.31 | - |
| 2041 | 435 | 390 | 95 | [redacted] | | | $ 4.69 | $ 18.68 | - |
| 2042 | 435 | 390 | 95 | [redacted] | | | $ 4.78 | $ 19.05 | - |
| 2043 | 435 | 390 | 95 | [redacted] | | | $ 4.88 | $ 19.43 | - |
| 2044 | 435 | 390 | 95 | [redacted] | | | $ 4.97 | $ 19.82 | - |
| 2045 | 435 | 390 | 95 | [redacted] | | | $ 5.07 | $ 20.21 | - |

**New-Build SC-CT (430 MW, 2X GE 7FA.05)**

| *Years* | Capability (Per 2X 'Block') Max(Sum) | Capability (Per 2X 'Block') Min | Heat Rate -Avg Annual- | Avg. Availability | Fuel Cost @ 'TCO Pool' ** | VOM | FOM | On-Going Capital*** |
|---|---|---|---|---|---|---|---|---|
| | (MW) | (MW) | (Btu/kWh) | (%) | ($/MMBtu) | ($/Mwh) | ($/kW-Yr) | ($/kW-Yr) |
| 2016 | - | - | - | | - | - | - | - |
| 2017 | - | - | - | | - | - | - | - |
| 2018 | - | - | - | | - | - | - | - |
| 2019 | - | - | - | | - | - | - | - |
| 2020 Opt 2 | 431 | 95 | [redacted] | | | $ 1.59 | $ 9.78 | - |
| 2021 | 431 | 95 | [redacted] | | | $ 1.62 | $ 9.98 | - |
| 2022 | 431 | 95 | [redacted] | | | $ 1.65 | $ 10.18 | - |
| 2023 Opt 1B | 431 | 95 | [redacted] | | | $ 1.69 | $ 10.38 | - |
| 2024 | 431 | 95 | [redacted] | | | $ 1.72 | $ 10.59 | - |
| 2025 | 431 | 95 | [redacted] | | | $ 1.76 | $ 10.80 | - |
| 2026 | 431 | 95 | [redacted] | | | $ 1.79 | $ 11.02 | - |
| 2027 | 431 | 95 | [redacted] | | | $ 1.83 | $ 11.24 | - |
| 2028 | 431 | 95 | [redacted] | | | $ 1.86 | $ 11.46 | - |
| 2029 | 431 | 95 | [redacted] | | | $ 1.90 | $ 11.69 | - |
| 2030 | 431 | 95 | [redacted] | | | $ 1.94 | $ 11.92 | - |
| 2031 | 431 | 95 | [redacted] | | | $ 1.98 | $ 12.16 | - |
| 2032 | 431 | 95 | [redacted] | | | $ 2.02 | $ 12.41 | - |
| 2033 | 431 | 95 | [redacted] | | | $ 2.06 | $ 12.65 | - |
| 2034 | 431 | 95 | [redacted] | | | $ 2.10 | $ 12.91 | - |
| 2035 | 431 | 95 | [redacted] | | | $ 2.14 | $ 13.17 | - |
| 2036 | 431 | 95 | [redacted] | | | $ 2.18 | $ 13.43 | - |
| 2037 | 431 | 95 | [redacted] | | | $ 2.23 | $ 13.70 | - |
| 2038 | 431 | 95 | [redacted] | | | $ 2.27 | $ 13.97 | - |
| 2039 | 431 | 95 | [redacted] | | | $ 2.32 | $ 14.25 | - |
| 2040 | 431 | 95 | [redacted] | | | $ 2.36 | $ 14.54 | - |
| 2041 | 431 | 95 | [redacted] | | | $ 2.41 | $ 14.83 | - |
| 2042 | 431 | 95 | [redacted] | | | $ 2.46 | $ 15.12 | - |
| 2043 | 431 | 95 | [redacted] | | | $ 2.51 | $ 15.43 | - |
| 2044 | 431 | 95 | [redacted] | | | $ 2.56 | $ 15.73 | - |
| 2045 | 431 | 95 | [redacted] | | | $ 2.61 | $ 16.05 | - |

**New-Build SC-CT (Small Frame: 189 MW, 2X GE 7FA.05)**

| *Years* | Capability (Per 2X 'Block') Max(Sum) | Capability (Per 2X 'Block') Min | Heat Rate -Avg Annual- | Avg. Availability | Fuel Cost @ 'TCO Pool' ** | VOM | FOM | On-Going Capital*** |
|---|---|---|---|---|---|---|---|---|
| | (MW) | (MW) | (Btu/kWh) | (%) | ($/MMBtu) | ($/Mwh) | ($/kW-Yr) | ($/kW-Yr) |
| 2016 | - | - | - | - | - | - | - | - |
| 2017 | - | - | - | - | - | - | - | - |
| 2018 | - | - | - | - | - | - | - | - |
| 2019 | - | - | - | - | - | - | - | - |
| 2020 Opt 2 | 179 | 84 | [redacted] | | | $ 1.59 | $ 15.67 | - |
| 2021 | 179 | 84 | [redacted] | | | $ 1.62 | $ 15.98 | - |
| 2022 | 179 | 84 | [redacted] | | | $ 1.65 | $ 16.30 | - |
| 2023 Opt 1B | 179 | 84 | [redacted] | | | $ 1.69 | $ 16.63 | - |
| 2024 | 179 | 84 | [redacted] | | | $ 1.72 | $ 16.96 | - |
| 2025 | 179 | 84 | [redacted] | | | $ 1.76 | $ 17.30 | - |
| 2026 | 179 | 84 | [redacted] | | | $ 1.79 | $ 17.64 | - |
| 2027 | 179 | 84 | [redacted] | | | $ 1.83 | $ 18.00 | - |
| 2028 | 179 | 84 | [redacted] | | | $ 1.86 | $ 18.36 | - |
| 2029 | 179 | 84 | [redacted] | | | $ 1.90 | $ 18.72 | - |
| 2030 | 179 | 84 | [redacted] | | | $ 1.94 | $ 19.10 | - |
| 2031 | 179 | 84 | [redacted] | | | $ 1.98 | $ 19.48 | - |
| 2032 | 179 | 84 | [redacted] | | | $ 2.02 | $ 19.87 | - |
| 2033 | 179 | 84 | [redacted] | | | $ 2.06 | $ 20.27 | - |
| 2034 | 179 | 84 | [redacted] | | | $ 2.10 | $ 20.67 | - |
| 2035 | 179 | 84 | [redacted] | | | $ 2.14 | $ 21.09 | - |
| 2036 | 179 | 84 | [redacted] | | | $ 2.18 | $ 21.51 | - |
| 2037 | 179 | 84 | [redacted] | | | $ 2.23 | $ 21.94 | - |
| 2038 | 179 | 84 | [redacted] | | | $ 2.27 | $ 22.38 | - |
| 2039 | 179 | 84 | [redacted] | | | $ 2.32 | $ 22.82 | - |
| 2040 | 179 | 84 | [redacted] | | | $ 2.36 | $ 23.28 | - |
| 2041 | 179 | 84 | [redacted] | | | $ 2.41 | $ 23.75 | - |
| 2042 | 179 | 84 | [redacted] | | | $ 2.46 | $ 24.22 | - |
| 2043 | 179 | 84 | [redacted] | | | $ 2.51 | $ 24.71 | - |
| 2044 | 179 | 84 | [redacted] | | | $ 2.56 | $ 25.20 | - |
| 2045 | 179 | 84 | [redacted] | | | $ 2.61 | $ 25.70 | - |

**New-Build Aeroderivative (87 MW, 2X GE-LM600 Sprint)**

| | Capability (Per 2X 'Block') Max(Sum) | Capability (Per 2X 'Block') Min | Heat Rate -Avg Annual- | Fuel Cost @ 'TCO Pool' ** | VOM | FOM | On-Going Capital*** |
|---|---|---|---|---|---|---|---|
| | (MW) | (MW) | (Btu/kWh) | ($/MMBtu) | ($/Mwh) | ($/kW-Yr) | ($/kW-Yr) |
| 2016 | - | - | - | - | - | - | - |
| 2017 | - | - | - | - | - | - | - |
| 2018 | - | - | - | - | - | - | - |
| 2019 | - | - | - | - | - | - | - |
| 2020 Opt 2 | 87 | 44 | [redacted] | | $ 3.64 | $ 13.54 | - |
| 2021 | 87 | 44 | [redacted] | | $ 3.72 | $ 13.81 | - |
| 2022 | 87 | 44 | [redacted] | | $ 3.79 | $ 14.08 | - |
| 2023 Opt 18 | 87 | 44 | [redacted] | | $ 3.87 | $ 14.36 | - |
| 2024 | 87 | 44 | [redacted] | | $ 3.94 | $ 14.65 | - |
| 2025 | 87 | 44 | [redacted] | | $ 4.02 | $ 14.94 | - |
| 2026 | 87 | 44 | [redacted] | | $ 4.10 | $ 15.24 | - |
| 2027 | 87 | 44 | [redacted] | | $ 4.19 | $ 15.55 | - |
| 2028 | 87 | 44 | [redacted] | | $ 4.27 | $ 15.86 | - |
| 2029 | 87 | 44 | [redacted] | | $ 4.35 | $ 16.18 | - |
| 2030 | 87 | 44 | [redacted] | | $ 4.44 | $ 16.50 | - |
| 2031 | 87 | 44 | [redacted] | | $ 4.53 | $ 16.83 | - |
| 2032 | 87 | 44 | [redacted] | | $ 4.62 | $ 17.17 | - |
| 2033 | 87 | 44 | [redacted] | | $ 4.71 | $ 17.51 | - |
| 2034 | 87 | 44 | [redacted] | | $ 4.81 | $ 17.86 | - |
| 2035 | 87 | 44 | [redacted] | | $ 4.90 | $ 18.22 | - |
| 2036 | 87 | 44 | [redacted] | | $ 5.00 | $ 18.58 | - |
| 2037 | 87 | 44 | [redacted] | | $ 5.10 | $ 18.95 | - |
| 2038 | 87 | 44 | [redacted] | | $ 5.20 | $ 19.33 | - |
| 2039 | 87 | 44 | [redacted] | | $ 5.31 | $ 19.72 | - |
| 2040 | 87 | 44 | [redacted] | | $ 5.41 | $ 20.11 | - |
| 2041 | 87 | 44 | [redacted] | | $ 5.52 | $ 20.52 | - |
| 2042 | 87 | 44 | [redacted] | | $ 5.63 | $ 20.93 | - |
| 2043 | 87 | 44 | [redacted] | | $ 5.75 | $ 21.34 | - |
| 2044 | 87 | 44 | [redacted] | | $ 5.86 | $ 21.77 | - |
| 2045 | 87 | 44 | [redacted] | | $ 5.98 | $ 22.21 | - |

**New-Build CHP (15 MW, GE-LM600 Sprint w/ Steam Host)**

| | Capability (Per 2X 'Block') Max(Sum) | Capability (Per 2X 'Block') Min | Heat Rate -Avg Annual- | Fuel Cost @ 'TCO Pool' ** | VOM | FOM | On-Going Capital*** |
|---|---|---|---|---|---|---|---|
| | (MW) | (MW) | (Btu/kWh) | ($/MMBtu) | ($/Mwh) | ($/kW-Yr) | ($/kW-Yr) |
| 2016 | - | - | - | - | - | - | - |
| 2017 | - | - | - | - | - | - | - |
| 2018 | - | - | - | - | - | - | - |
| 2019 | - | - | - | - | - | - | - |
| 2020 Opt 2 | 15 | 7 | [redacted] | | $ 1.44 | $ 54.43 | - |
| 2021 | 15 | 7 | [redacted] | | $ 1.46 | $ 55.52 | - |
| 2022 | 15 | 7 | [redacted] | | $ 1.49 | $ 56.63 | - |
| 2023 Opt 18 | 15 | 7 | [redacted] | | $ 1.53 | $ 57.76 | - |
| 2024 | 15 | 7 | [redacted] | | $ 1.55 | $ 58.91 | - |
| 2025 | 15 | 7 | [redacted] | | $ 1.59 | $ 60.09 | - |
| 2026 | 15 | 7 | [redacted] | | $ 1.62 | $ 61.29 | - |
| 2027 | 15 | 7 | [redacted] | | $ 1.65 | $ 62.52 | - |
| 2028 | 15 | 7 | [redacted] | | $ 1.68 | $ 63.77 | - |
| 2029 | 15 | 7 | [redacted] | | $ 1.72 | $ 65.05 | - |
| 2030 | 15 | 7 | [redacted] | | $ 1.75 | $ 66.35 | - |
| 2031 | 15 | 7 | [redacted] | | $ 1.79 | $ 67.67 | - |
| 2032 | 15 | 7 | [redacted] | | $ 1.82 | $ 69.03 | - |
| 2033 | 15 | 7 | [redacted] | | $ 1.86 | $ 70.41 | - |
| 2034 | 15 | 7 | [redacted] | | $ 1.90 | $ 71.82 | - |
| 2035 | 15 | 7 | [redacted] | | $ 1.93 | $ 73.25 | - |
| 2036 | 15 | 7 | [redacted] | | $ 1.97 | $ 74.72 | - |
| 2037 | 15 | 7 | [redacted] | | $ 2.01 | $ 76.21 | - |
| 2038 | 15 | 7 | [redacted] | | $ 2.05 | $ 77.74 | - |
| 2039 | 15 | 7 | [redacted] | | $ 2.09 | $ 79.29 | - |
| 2040 | 15 | 7 | [redacted] | | $ 2.13 | $ 80.88 | - |
| 2041 | 15 | 7 | [redacted] | | $ 2.18 | $ 82.49 | - |
| 2042 | 15 | 7 | [redacted] | | $ 2.22 | $ 84.14 | - |
| 2043 | 15 | 7 | [redacted] | | $ 2.27 | $ 85.83 | - |
| 2044 | 15 | 7 | [redacted] | | $ 2.31 | $ 87.54 | - |
| 2045 | 15 | 7 | [redacted] | | $ 2.36 | $ 89.29 | - |

* As a practical matter, due to poorer thermal efficiency/heat rate, evaporator cooling would be limited during higher temperature periods. Therefore, for dispatch (energy) modeling purposes, a slightly lower 'nominal' rating --and (lower/improved) attendant Heat Rate-- was utilized throughout the forecast period... However, Max(Sum) "with evaporating-cooling" Capability *was* recognized for purposes of determination of attributable PJM (summer) unforced capability (UCAP) value.

** Per 'BASE' pricing scenario, inclusive of Swing Service Adder.

*** 'On-Going Capital' expenditures are assumed to be incorporated into the Fixed O&M (FOM) estimates shown.

**Indiana Michigan Power Co.**
Rockport Unit 2 Disposition Analysis
*Long-Term, Life Cycle Economics (2016-2045, with end-effects)*

***COMPARATIVE*** **Cumulative Present Worth (CPW) of I&M Net Utility "Generation" Costs (2016 $)**
**(COST / <SAVINGS> )**

| **$ Millions** | **Option #1B** RETROFIT RK2 w/ SCR (12/2019); **then** RETURN (to Lessor) at 12/2022 Lease Termination **& REPLACE RKU2 w/ New-Build Resources (1/2023)** | **Option #2** NO RK2 SCR... RETURN (to Lessor) at 12/2019 Early Termination **& REPLACE RK U2 w/ New-Build Resources (1/2020)** |
|---|---|---|
| | ***over*** | ***over*** |
| | **Option #1A** RETROFIT Rockport Unit 2 with SCR (12/2019) then --*for modeling purposes only*-- assume NPDES/ELG/CCR-related equipment installed (total Plant) by 2019-2021, and **RKU2 DFGD and associated equipment installed by 12/2028** | |
| L/T Commodity Pricing Scenarios | | |
| "BASE" Forecast | **84** | **322** |
| *Alternative Scenario Pricing...* | | |
| "Lower Band" | (131) | **99** |
| "Higher Band" | **349** | **621** |
| "No Carbon" | **233** | **485** |
| "High Carbon" | (90) | **142** |

*Notes:*

- o All scenario pricing alternatives (excluding "No $CO_2$") assume carbon/$CO_2$ pricing is effective in 2022
- o Option #1A (RK U2 w/ SCR & DFGD) assumes investment recovery period for SCR (beg. 2020), and DFGD (beg. 2029), of 10 and 20-years, respectively
- o Option #1B (RK U2 w/ SCR [only]) assumes investment recovery period for SCR (beg. 2020) of 10-years
- o Option #2 (RK U2 No SCR Return to Lessor 12/2019) assumes a 30-year recovery period for any replacment resources (CC and/or CTs, AD, CHP) in all analyses
- o Each Rockport unit reflects I&M's 50% (650-MW) Ownership share; plus 70% (455-MW) Purch.Entitlement from affiliate AEP Generating Cos.'

**Indiana Michigan Power Co.**

Rockport Unit 2 Disposition Analysis

*Long-Term, Life Cycle Economics (2016-2045, with end-effects)*

***COMPARATIVE*** **Cumulative Present Worth (CPW) of I&M Net Utility "Generation" Costs (2016 $)**
**(COST / <SAVINGS> )**

**$ Millions**

| | **Option #1A** RETROFIT RK2 w/ SCR (12/2019) **then** --*for modeling purposes only*-- **install NPDES/ELG/CCR-related equiment in 2019-2021, then RKU2 DFGD by 12/2028** | **Option #2** NO RK2 SCR... RETURN (to Lessor) at 12/2019 Early Termination **& REPLACE RK U2 w/ New-Build Resources (1/2020)** |
|---|---|---|
| | ***over*** | ***over*** |
| | **Option #1B** RETROFIT Rockport Unit 2 with SCR (12/2019) **then** RETURN (to Lessor) at 12/2022 Lease Termination **& REPLACE RKU2 w/ New-Build Resources (1/2023)** | |
| L/T Commodity Pricing Scenarios | | |
| "BASE" Forecast | (84) | **239** |
| *Alternative Scenario Pricing...* | | |
| "Lower Band" | **131** | **230** |
| "Higher Band" | (349) | **272** |
| "No Carbon" | (233) | **252** |
| "High Carbon" | **90** | **233** |

*Notes:*

- o All scenario pricing alternatives (excluding "No $CO_2$") assume carbon/$CO_2$ pricing is effective in 2022
- o Option #1A (RK U2 w/ SCR & DFGD) assumes investment recovery period for SCR (beg. 2020), and DFGD (beg. 2029), of 10 and 20-years, respectively
- o Option #1B (RK U2 w/ SCR [only]) assumes investment recovery period for SCR (beg. 2020) of 10-years
- o Option #2 (RK U2 No SCR Return to Lessor 12/2019) assumes a 30-year recovery period for any replacment resources (CC and/or CTs, AD, CHP) in all analyses
- o Each Rockport unit reflects I&M's 50% (650-MW) Ownership share; plus 70% (455-MW) Purch.Entitlement from affiliate AEP Generating Cos.' 50% ownership share

INDIANA MICHIGAN POWER COMPANY

*Rockport Unit 2 Disposition Analysis*

**"BASE" Long-term Commodity Pricing Forecast**

| | CPW ($000) | | | *CPW Cost/ <Savings> Over 'Option 1A'* | | | *CPW Cost/ <Savings> Over 'Option 1B'* | | |
|---|---|---|---|---|---|---|---|---|---|
| *Disposition Alternative* [1] | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period |
| *Rockport 2 SCR:* | | | | | | | | | |
| **Option 1A** [2] | 12,579,284 | 3,573,614 | 16,152,898 | - | - | - | 84,431 | (168,061) | ***(83,630)*** |
| **Option 1B** [3] | 12,494,853 | 3,741,675 | 16,236,528 | (84,431) | 168,061 | ***83,630*** | - | - | - |
| *No Rockport 2 SCR:* | | | | | | | | | |
| **Option 2** [4] | 12,748,173 | 3,727,194 | 16,475,367 | 168,889 | 153,580 | ***322,469*** | 253,320 | (14,482) | ***238,839*** |
| (SENSITIVITY) **Option 2A** [5] | 12,755,098 | 3,743,742 | 16,498,840 | 175,814 | 170,128 | ***345,942*** | 260,246 | 2,067 | ***262,312*** |

Note:

(1) All cases assume Rockport Unit 1 SCR installation by 12/31/2017, and DFGD installation by 12/31/2025

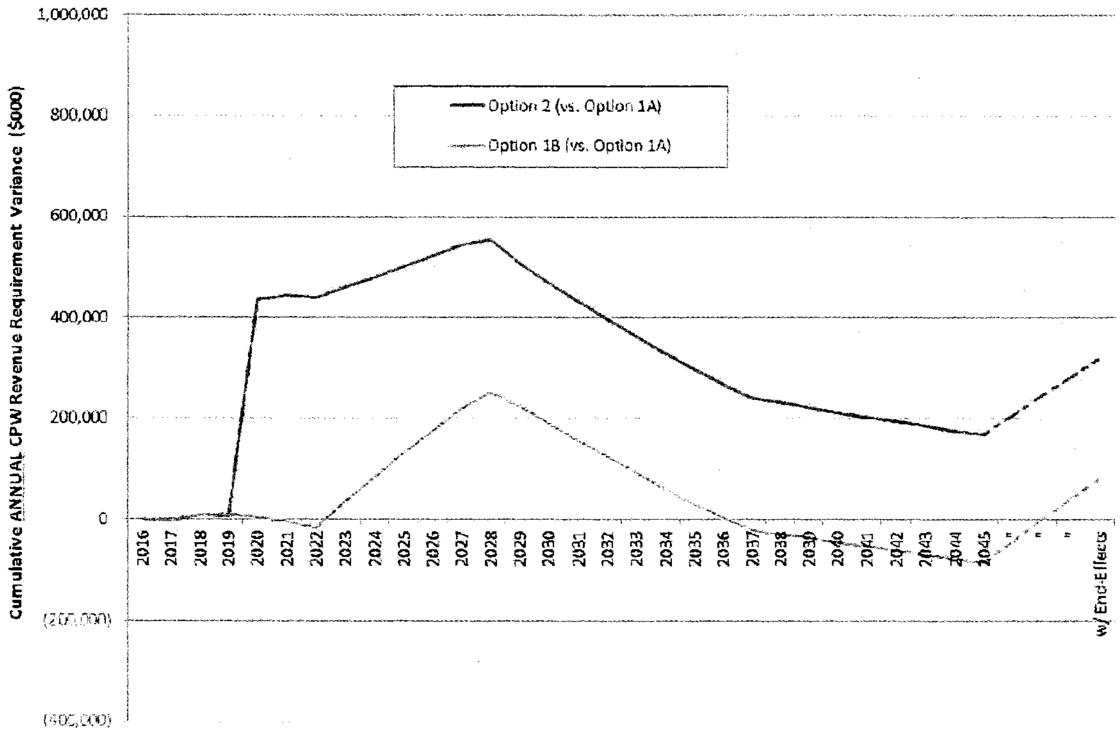
(2) Option 1A assumes Rockport Unit 2 SCR installation by 12/31/2019 and DFGD installation by 12/31/2028

(3) Option 1B assumes Rockport Unit 2 SCR installation by 12/31/2019, but No DFGD installation...
returning the unit to the Lessor by 12/31/2022 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2023

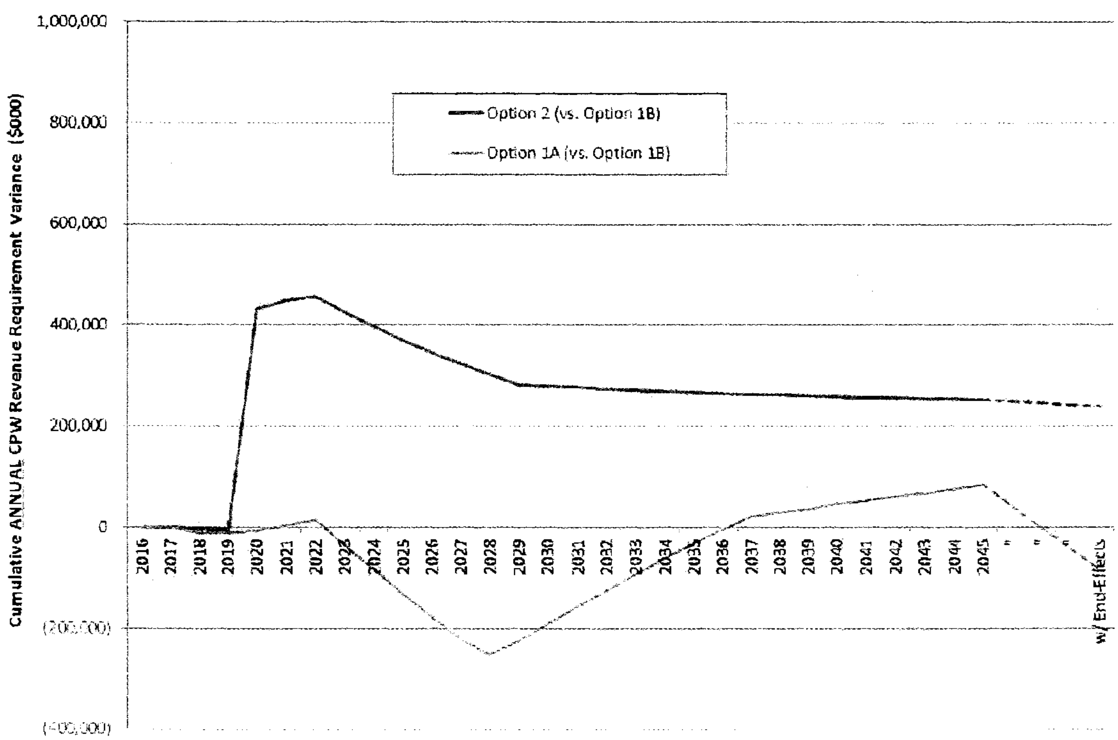
(4) Option 2 assumes No Rockport Unit 2 SCR installation by 12/31/2019... terminating the operating lease and
returning the unit to the Lessor by 12/31/2019 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2020

(5) *same as 'Option 2' except assume any replacement CC capacity would be delayed until 1/1/2023 (relying on the PJM capacity & energy market in the interim)*

**Rockport 2 SCR-CCT Project ANNUAL Relative Economics:**
**Cost / <Savings> of Options 1B (SCR only; No DFGD) & Option 2 (No SCR) *versus Option 1A* (SCR & DFGD)**
'BASE' L/T Commodity Pricing




**Rockport 2 SCR-CCT Project ANNUAL Relative Economics:**
**Cost / <Savings> of Options 1A (SCR & DFGD) & Option 2 (No SCR) *versus Option 1B* (SCR only; No DFGD)**
'BASE' L/T Commodity Pricing



INDIANA MICHIGAN POWER COMPANY

*Rockport Unit 2 Disposition Analysis*

**"Lower Band" Long-term Commodity Pricing Forecast**

| Disposition Alternative[1] | CPW ($000) | | | *CPW Cost/<Savings> Over 'Option **1A**'* | | | *CPW Cost/<Savings> Over 'Option **1B**'* | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period |
| *Rockport 2 SCR:* | | | | | | | | | |
| **Option 1A**[2] | 12,705,895 | 3,455,205 | 16,161,100 | - | - | - | 232,324 | (101,302) | ***131,022*** |
| **Option 1B**[3] | 12,473,571 | 3,556,507 | 16,030,078 | (232,324) | 101,302 | *(131,022)* | - | - | - |
| *No Rockport 2 SCR:* | | | | | | | | | |
| **Option 2**[4] | 12,717,690 | 3,542,025 | 16,259,716 | 11,795 | 86,820 | ***98,615*** | 244,119 | (14,482) | ***229,637*** |
| (SENSITIVITY) **Option 2A**[5] | 12,710,770 | 3,558,574 | 16,269,344 | 4,875 | 103,369 | ***108,244*** | 237,199 | 2,067 | ***239,266*** |

Note:

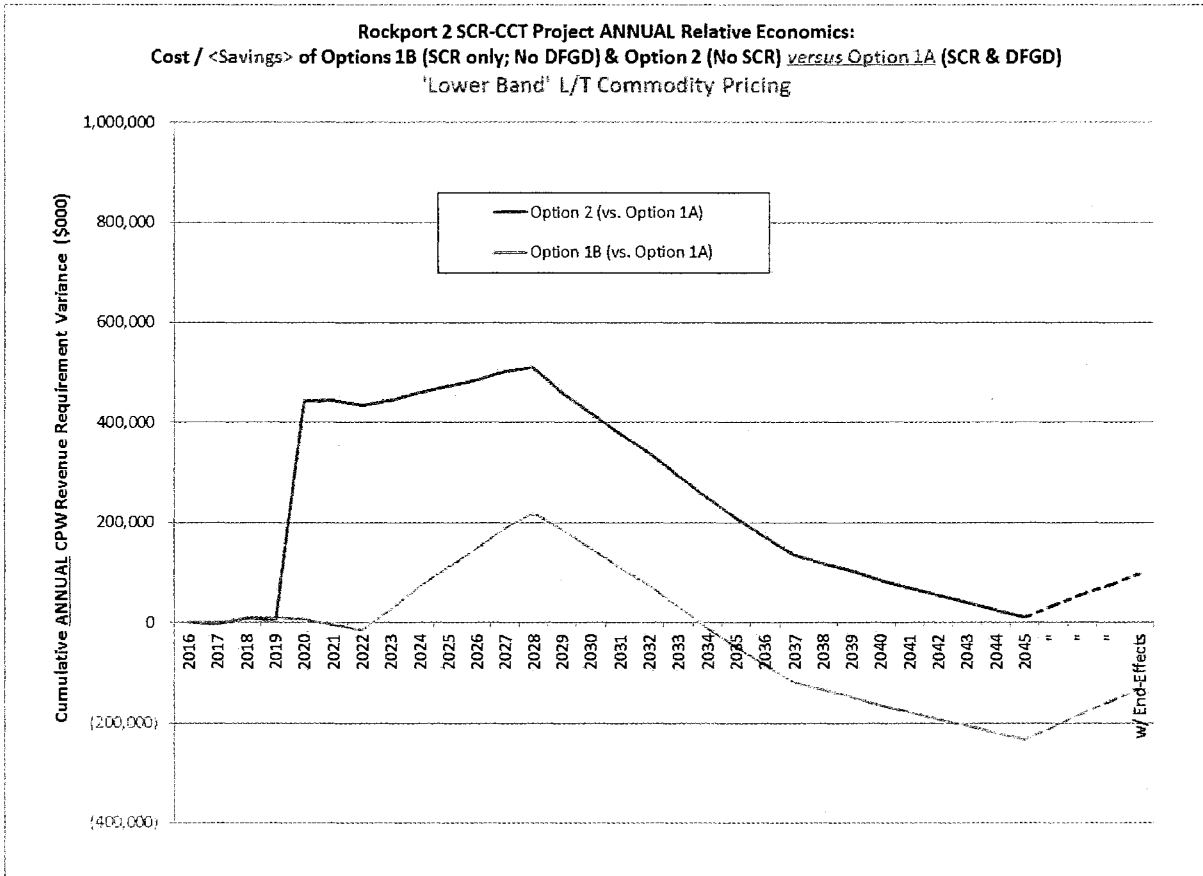
(1) All cases assume Rockport Unit 1 SCR installation by 12/31/2017, and DFGD installation by 12/31/2025

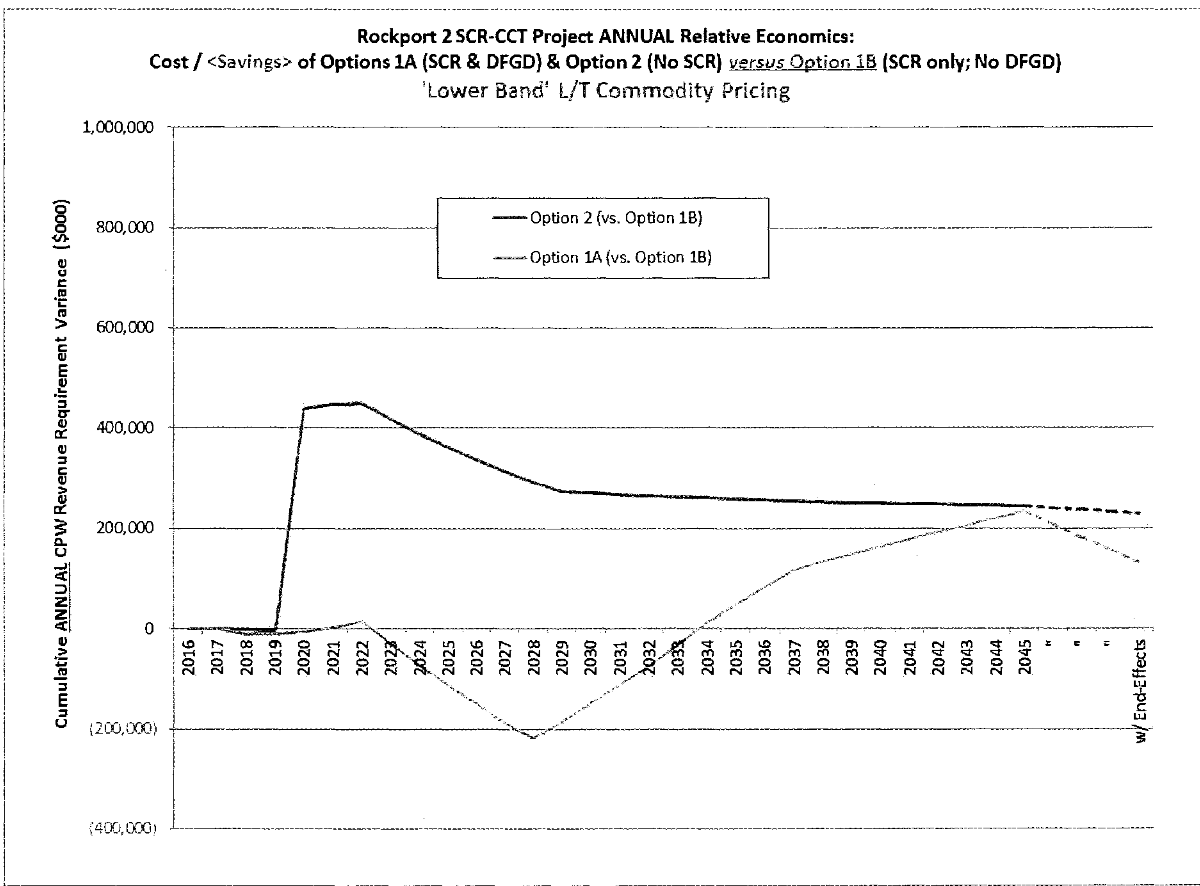
(2) Option 1A assumes Rockport Unit 2 SCR installation by 12/31/2019 and DFGD installation by 12/31/2028

(3) Option 1B assumes Rockport Unit 2 SCR installation by 12/31/2019, but No DFGD installation...
returning the unit to the Lessor by 12/31/2022 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2023

(4) Option 2 assumes No Rockport Unit 2 SCR installation by 12/31/2019... terminating the operating lease and
returning the unit to the Lessor by 12/31/2019 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2020

(5) *same as 'Option 2' except assume any replacement CC capacity would be delayed until 1/1/2023 (relying on the PJM capacity & energy market in the interim)*


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1B (SCR only; No DFGD) & Option 2 (No SCR) versus Option 1A (SCR & DFGD)
'Lower Band' L/T Commodity Pricing
Option 2 (vs. Option 1A)
Option 1B (vs. Option 1A)
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1A (SCR & DFGD) & Option 2 (No SCR) versus Option 1B (SCR only; No DFGD)
'Lower Band' L/T Commodity Pricing
Option 2 (vs. Option 1B)
Option 1A (vs. Option 1B)
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects

INDIANA MICHIGAN POWER COMPANY

*Rockport Unit 2 Disposition Analysis*

"Higher Band" Long-term Commodity Pricing Forecast

| | CPW ($000) | | | *CPW Cost/<Savings> Over 'Option **1A**'* | | | *CPW Cost/<Savings> Over 'Option **1B**'* | | |
|---|---|---|---|---|---|---|---|---|---|
| *Disposition Alternative* [1] | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period |
| *Rockport 2 SCR:* | | | | | | | | | |
| **Option 1A** [2] | 12,618,732 | 3,629,861 | 16,248,593 | - | - | - | (20,041) | (328,818) | ***(348,858)*** |
| **Option 1B** [3] | 12,638,773 | 3,958,679 | 16,597,452 | 20,041 | 328,818 | ***348,858*** | - | - | - |
| *No Rockport 2 SCR:* | | | | | | | | | |
| **Option 2** [4] | 12,925,508 | 3,944,197 | 16,869,705 | 306,776 | 314,336 | ***621,112*** | 286,735 | (14,482) | ***272,254*** |
| (SENSITIVITY) **Option 2A** [5] | 12,901,401 | 3,960,746 | 16,862,147 | 282,669 | 330,885 | ***613,554*** | 262,629 | 2,067 | ***264,695*** |

Note:

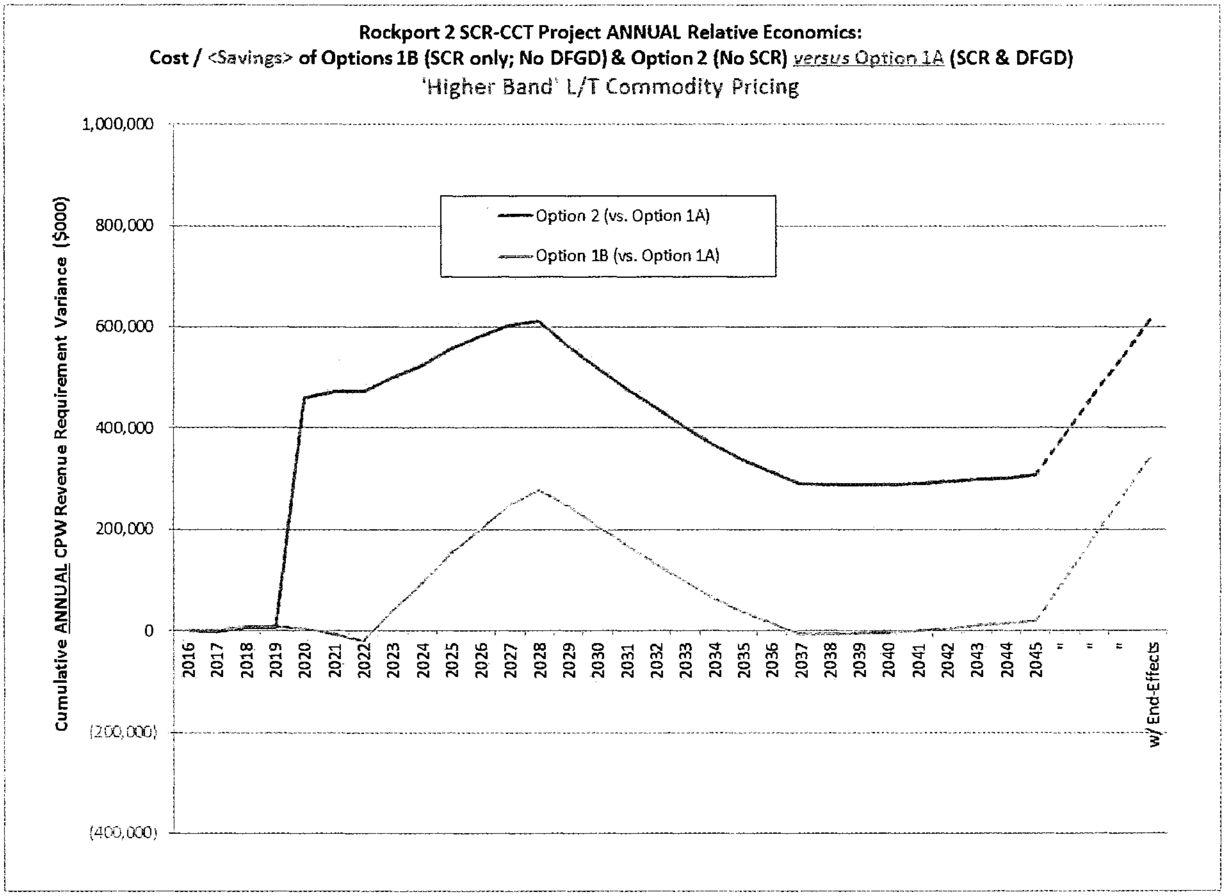
(1) All cases assume Rockport Unit 1 SCR installation by 12/31/2017, and DFGD installation by 12/31/2025

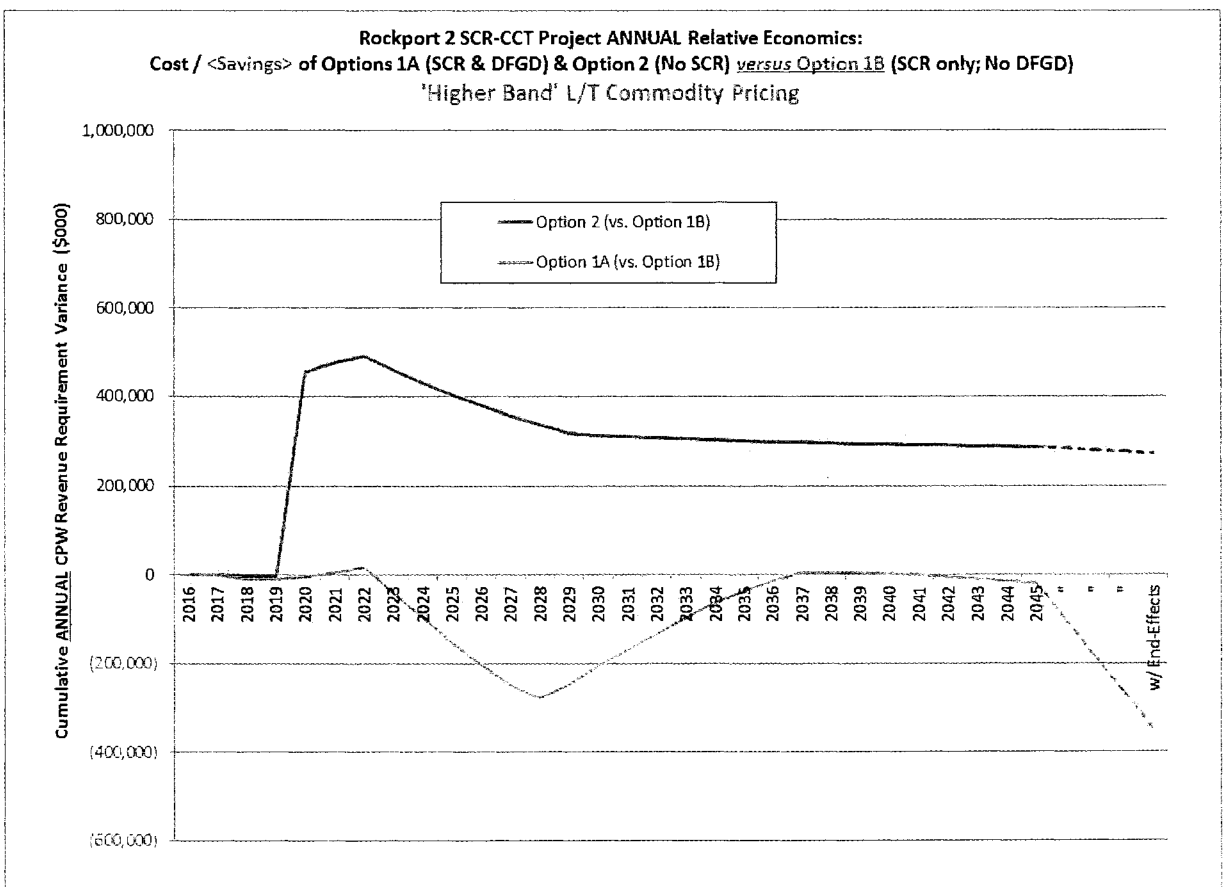
(2) Option 1A assumes Rockport Unit 2 SCR installation by 12/31/2019 and DFGD installation by 12/31/2028

(3) Option 1B assumes Rockport Unit 2 SCR installation by 12/31/2019, but No DFGD installation...
returning the unit to the Lessor by 12/31/2022 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2023

(4) Option 2 assumes No Rockport Unit 2 SCR installation by 12/31/2019... terminating the operating lease and
returning the unit to the Lessor by 12/31/2019 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2020

(5) *same as 'Option 2' except assume any replacement CC capacity would be delayed until 1/1/2023 (relying on the PJM capacity & energy market in the interim)*


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1B (SCR only; No DFGD) & Option 2 (No SCR) versus Option 1A (SCR & DFGD)
'Higher Band' L/T Commodity Pricing
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
Option 2 (vs. Option 1A)
Option 1B (vs. Option 1A)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1A (SCR & DFGD) & Option 2 (No SCR) versus Option 1B (SCR only; No DFGD)
'Higher Band' L/T Commodity Pricing
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
(600,000)
Option 2 (vs. Option 1B)
Option 1A (vs. Option 1B)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects

INDIANA MICHIGAN POWER COMPANY

*Rockport Unit 2 Disposition Analysis*

"No Carbon" Long-term Commodity Pricing Forecast

| | CPW ($000) | | | *CPW Cost/<Savings> Over 'Option **1A**'* | | | *CPW Cost/<Savings> Over 'Option **1B**'* | | |
|---|---|---|---|---|---|---|---|---|---|
| *Disposition Alternative* [1] | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period |
| *Rockport 2 SCR:* | | | | | | | | | |
| **Option 1A** [2] | 11,940,832 | 3,165,463 | 15,106,295 | - | - | - | (74,882) | (157,709) | ***(232,591)*** |
| **Option 1B** [3] | 12,015,714 | 3,323,172 | 15,338,886 | 74,882 | 157,709 | ***232,591*** | - | - | - |
| *No Rockport 2 SCR:* | | | | | | | | | |
| **Option 2** [4] | 12,282,405 | 3,308,690 | 15,591,096 | 341,573 | 143,228 | ***484,801*** | 266,691 | (14,482) | ***252,209*** |
| (SENSITIVITY) **Option 2A** [5] | 12,252,452 | 3,325,239 | 15,577,691 | 311,619 | 159,776 | ***471,395*** | 236,738 | 2,067 | ***238,804*** |

Note:

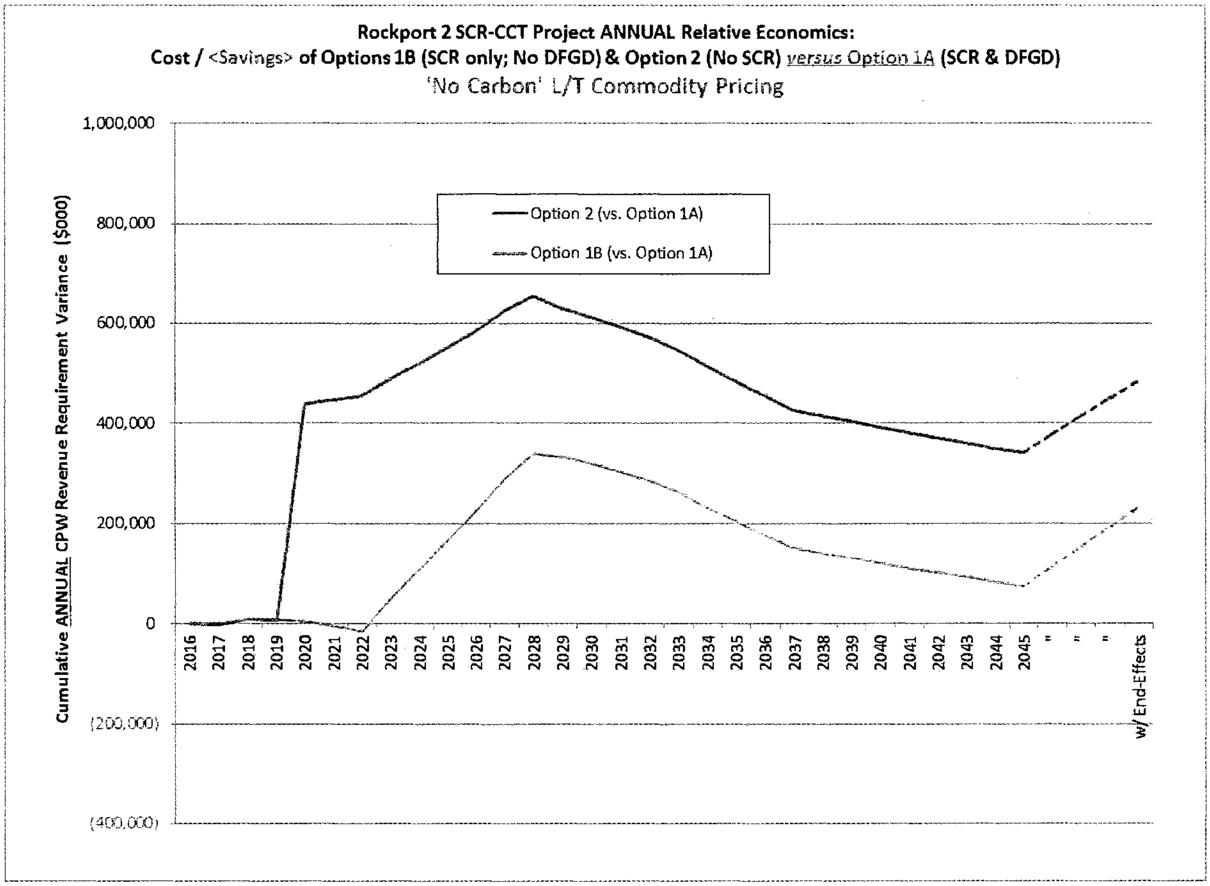
(1) All cases assume Rockport Unit 1 SCR installation by 12/31/2017, and DFGD installation by 12/31/2025

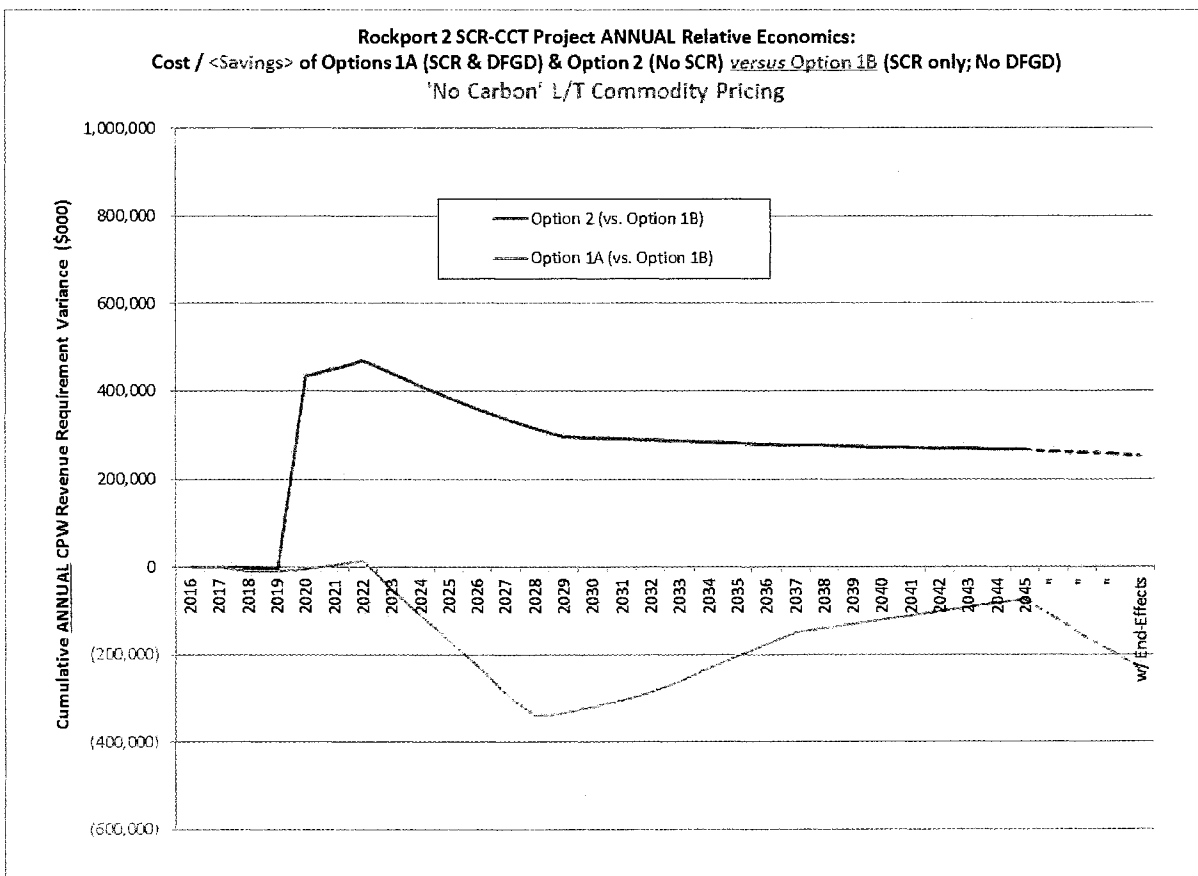
(2) Option 1A assumes Rockport Unit 2 SCR installation by 12/31/2019 and DFGD installation by 12/31/2028

(3) Option 1B assumes Rockport Unit 2 SCR installation by 12/31/2019, but No DFGD installation...
returning the unit to the Lessor by 12/31/2022 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2023

(4) Option 2 assumes No Rockport Unit 2 SCR installation by 12/31/2019... terminating the operating lease and
returning the unit to the Lessor by 12/31/2019 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2020

(5) *same as 'Option 2' except assume any replacement CC capacity would be delayed until 1/1/2023 (relying on the PJM capacity & energy market in the interim)*


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1B (SCR only; No DFGD) & Option 2 (No SCR) versus Option 1A (SCR & DFGD)
'No Carbon' L/T Commodity Pricing
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
Option 2 (vs. Option 1A)
Option 1B (vs. Option 1A)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
w/ End-Effects


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1A (SCR & DFGD) & Option 2 (No SCR) versus Option 1B (SCR only; No DFGD)
'No Carbon' L/T Commodity Pricing
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
Option 2 (vs. Option 1B)
Option 1A (vs. Option 1B)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
(600,000)
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
w/ End-Effects

INDIANA MICHIGAN POWER COMPANY

*Rockport Unit 2 Disposition Analysis*

**"High Carbon" Long-term Commodity Pricing Forecast**

| | CPW ($000) | | | *CPW Cost/ <Savings> Over 'Option **1A**'* | | | *CPW Cost/ <Savings> Over 'Option **1B**'* | | |
|---|---|---|---|---|---|---|---|---|---|
| *Disposition Alternative* [1] | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period | 2016-2045 Optimization Period | Plus: End-Effects | Total Study Period |
| *Rockport 2 SCR:* | | | | | | | | | |
| **Option 1A** [2] | 13,314,078 | 3,796,861 | 17,110,939 | - | - | - | 290,907 | (200,633) | ***90,274*** |
| **Option 1B** [3] | 13,023,172 | 3,997,494 | 17,020,665 | (290,907) | 200,633 | *(90,274)* | - | - | - |
| *No Rockport 2 SCR:* | | | | | | | | | |
| **Option 2** [4] | 13,270,242 | 3,983,012 | 17,253,253 | (43,837) | 186,151 | ***142,314*** | 247,070 | (14,482) | ***232,588*** |
| (SENSITIVITY) **Option 2A** [5] | 13,223,077 | 3,999,560 | 17,222,638 | (91,001) | 202,700 | ***111,698*** | 199,906 | 2,067 | ***201,972*** |

Note:

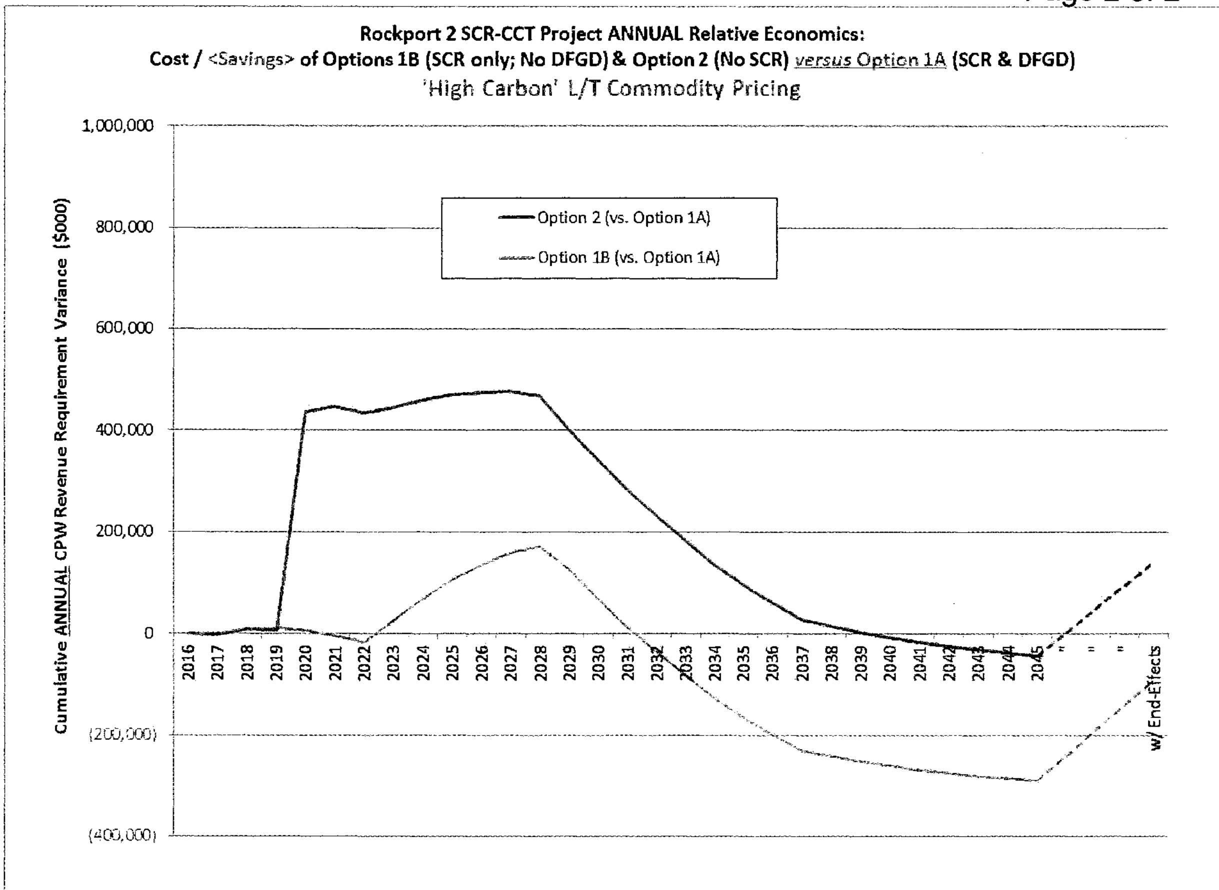
(1) All cases assume Rockport Unit 1 SCR installation by 12/31/2017, and DFGD installation by 12/31/2025

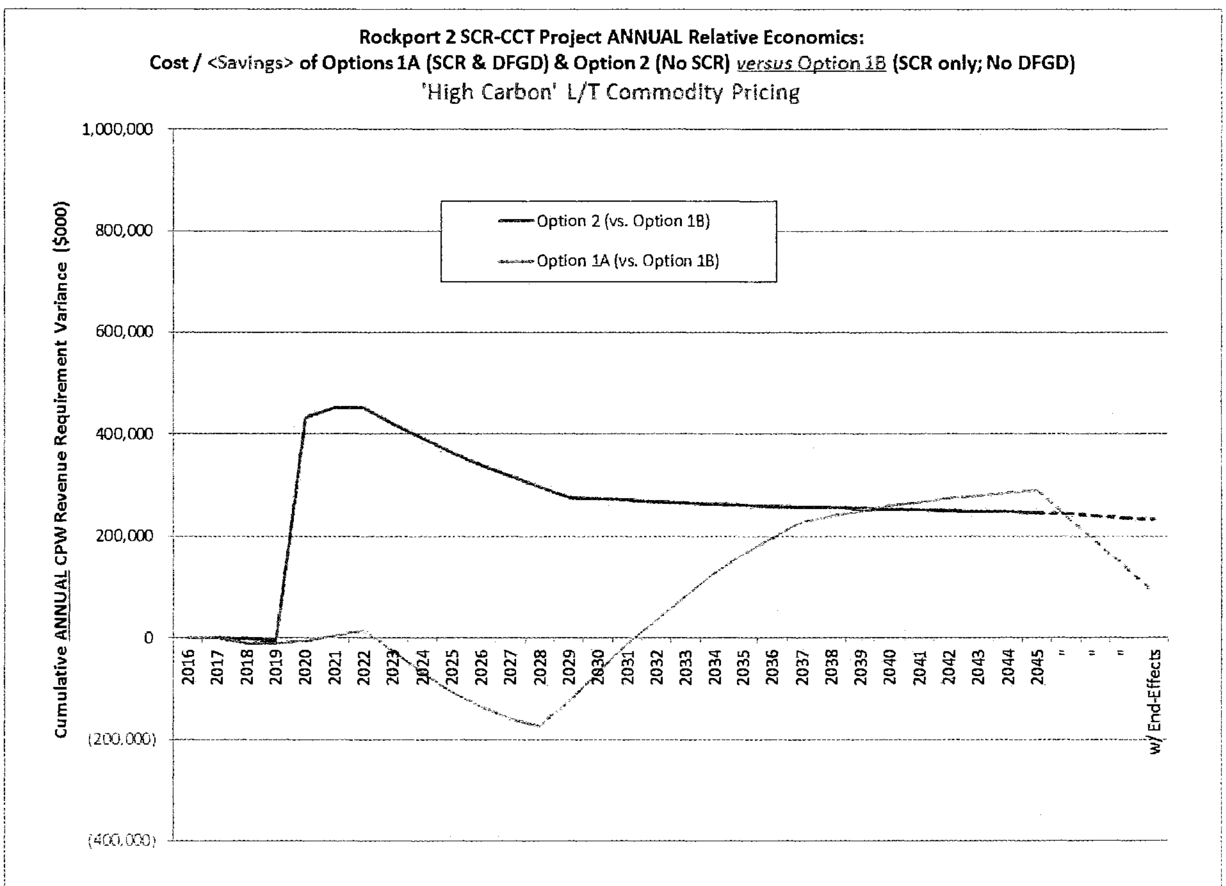
(2) Option 1A assumes Rockport Unit 2 SCR installation by 12/31/2019 and DFGD installation by 12/31/2028

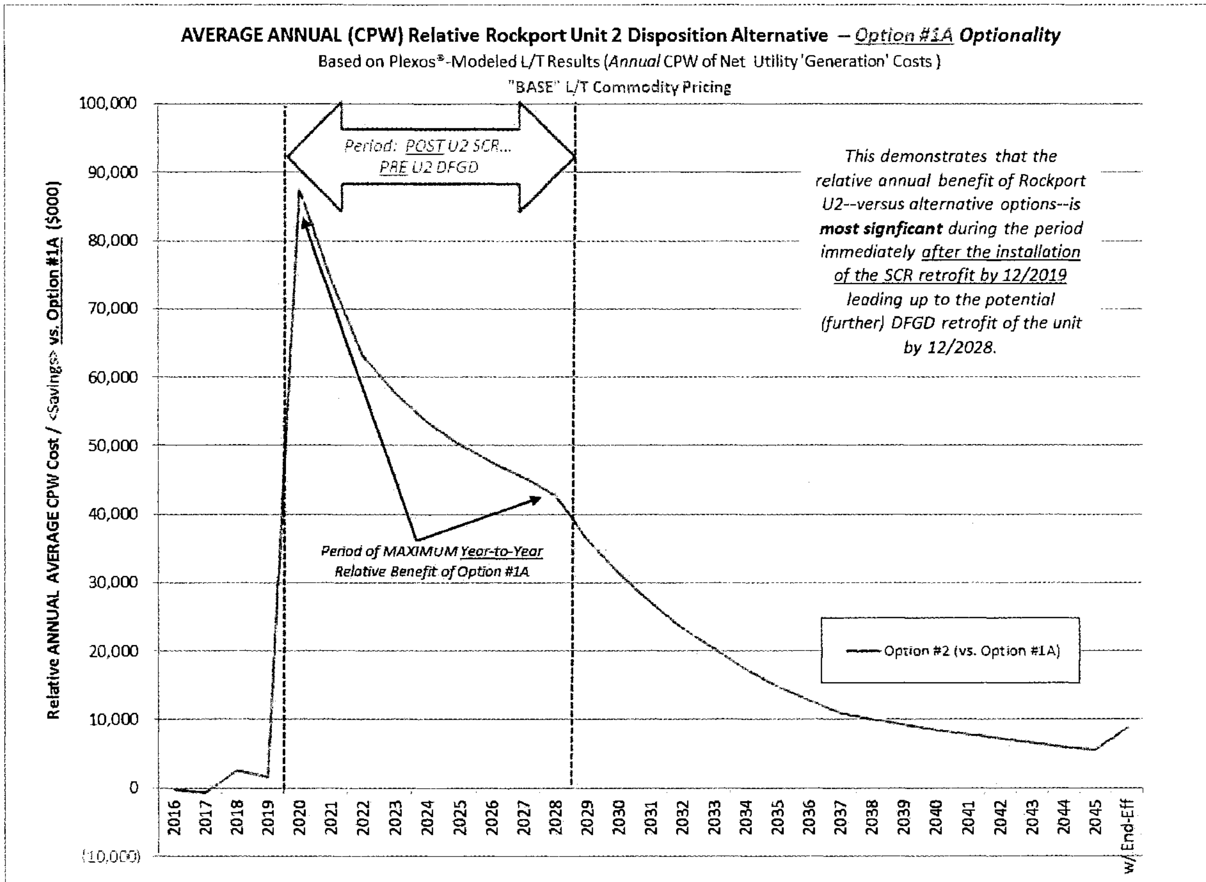
(3) Option 1B assumes Rockport Unit 2 SCR installation by 12/31/2019, but No DFGD installation...
returning the unit to the Lessor by 12/31/2022 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2023

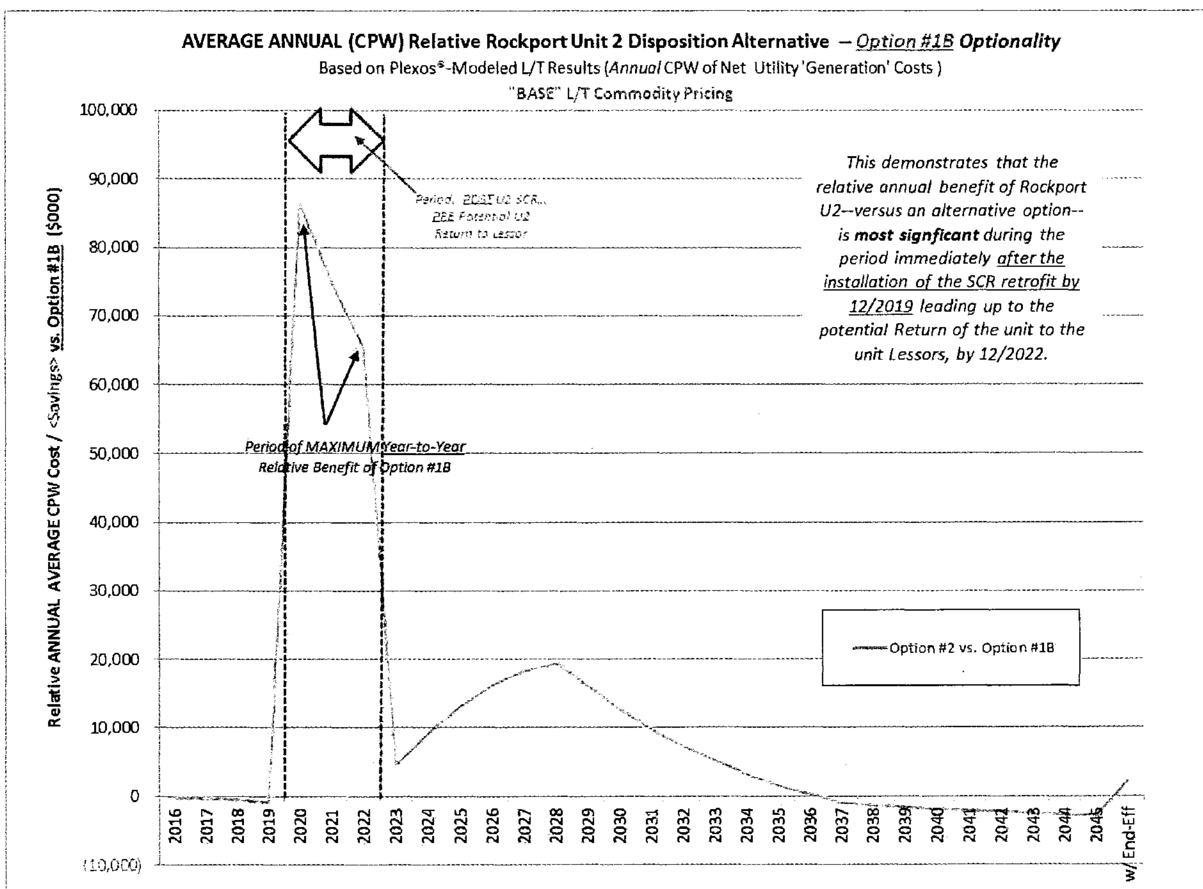
(4) Option 2 assumes No Rockport Unit 2 SCR installation by 12/31/2019... terminating the operating lease and
returning the unit to the Lessor by 12/31/2019 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2020

(5) *same as 'Option 2' except assume any replacement CC capacity would be delayed until 1/1/2023 (relying on the PJM capacity & energy market in the interim)*


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1B (SCR only; No DFGD) & Option 2 (No SCR) versus Option 1A (SCR & DFGD)
'High Carbon' L/T Commodity Pricing
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
Option 2 (vs. Option 1A)
Option 1B (vs. Option 1A)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1A (SCR & DFGD) & Option 2 (No SCR) versus Option 1B (SCR only; No DFGD)
'High Carbon' L/T Commodity Pricing
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
Option 2 (vs. Option 1B)
Option 1A (vs. Option 1B)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects


AVERAGE ANNUAL (CPW) Relative Rockport Unit 2 Disposition Alternative – Option #1A Optionality
Based on Plexos®-Modeled L/T Results (Annual CPW of Net Utility 'Generation' Costs)
"BASE" L/T Commodity Pricing
Period: POST U2 SCR... PRE U2 DFGD
This demonstrates that the relative annual benefit of Rockport U2--versus alternative options--is most signficant during the period immediately after the installation of the SCR retrofit by 12/2019 leading up to the potential (further) DFGD retrofit of the unit by 12/2028.
Period of MAXIMUM Year-to-Year Relative Benefit of Option #1A
Option #2 (vs. Option #1A)
Relative ANNUAL AVERAGE CPW Cost / <Savings> vs. Option #1A ($000)
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
(10,000)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 w/ End-Eff


AVERAGE ANNUAL (CPW) Relative Rockport Unit 2 Disposition Alternative – Option #1B Optionality
Based on Plexos®-Modeled L/T Results (Annual CPW of Net Utility 'Generation' Costs)
"BASE" L/T Commodity Pricing
This demonstrates that the relative annual benefit of Rockport U2--versus an alternative option--is most signficant during the period immediately after the installation of the SCR retrofit by 12/2019 leading up to the potential Return of the unit to the unit Lessors, by 12/2022.
Period of MAXIMUM Year-to-Year Relative Benefit of Option #1B
Option #2 vs. Option #1B
Relative ANNUAL AVERAGE CPW Cost / <Savings> vs. Option #1B ($000)
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
(10,000)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 w/ End-Eff

**Indiana Michigan Power Co.**
Rockport Unit 2 Disposition Analysis
*Under BASE L/T Commodity Pricing*

**Comparative SHORTER-TERM (thru 2022 & 2028) CPW of Relative I&M Net Utility "G(eneration)" Costs (1/2016 $)**

| | | | Option 1A (Retrofit RK2 with SCR (12/2019), then DFGD (12/2028)) | | | | | Option 1B (Retrofit RK2 with SCR (12/2019), then Return & Replace (1/2023)) | | | | | Option 2 (No SCR, Return & Replace 1/2020) | | | | Option 2 v. Option 1A | Option 2 v. Option 1B |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | GRAND Total Net Utility Costs | | / Yrs | = Total Cost, 'Per Year Avg' | | GRAND Total Net Utility Costs | | / Yrs | = Total Cost, 'Per Year Avg' | | GRAND Total Net Utility Costs | | / Yrs | = Total Cost, 'Per Year Avg' | Total Cost, 'Per Year Avg' | Total Cost, 'Per Year Avg' |
| Study Year # | Year | | (Nominal) $000 | (Cumul. PW) $000 | | (PW) $000 | | (Nominal) $000 | (Cumul. PW) $000 | | (PW) $000 | | (Nominal) $000 | (Cumul. PW) $000 | | (PW) $000 | (PW) $000 | (PW) $000 |
| 1 | 2016 | | 618,233 | 572,120 | /1 | 572,120 | | 618,233 | 572,120 | /1 | 572,120 | | 618,021 | 571,924 | /1 | 571,924 | (196) | (196) |
| 2 | 2017 | | 593,077 | 1,080,023 | /2 | 540,012 | | 592,271 | 1,079,333 | /2 | 539,667 | | 591,795 | 1,078,729 | /2 | 539,365 | (647) | (302) |
| 3 | 2018 | | 653,263 | 1,597,742 | /3 | 532,581 | | 665,960 | 1,607,114 | /3 | 535,705 | | 664,770 | 1,605,567 | /3 | 535,189 | 2,608 | (516) |
| 4 | 2019 | | 667,357 | 2,087,181 | /4 | 521,795 | | 668,223 | 2,097,188 | /4 | 524,297 | | 665,785 | 2,093,852 | /4 | 523,463 | 1,668 | (834) |
| 5 | 2020 | U2 SCR Installed | 701,129 | 2,563,034 | /5 | 512,607 | U2 SCR Installed | 694,348 | 2,568,439 | /5 | 513,688 | | 1,335,981 | 3,000,577 | /5 | 600,115 | 87,509 | 86,428 |
| 6 | 2021 | | 724,488 | 3,018,066 | /6 | 503,011 | | 709,729 | 3,014,201 | /6 | 502,367 | Return/ Rsrc Repl | 738,121 | 3,464,170 | /6 | 577,362 | 74,351 | 74,995 |
| 7 | 2022 | | 855,436 | 3,515,268 | /7 | 502,181 | | 834,763 | 3,499,387 | /7 | 499,912 | | 848,054 | 3,957,082 | /7 | 565,297 | 63,116 | 65,385 |
| 8 | 2023 | | 809,312 | 3,950,575 | /8 | 493,822 | Return/ Rsrc Repl | 904,622 | 3,985,959 | /8 | 498,245 | | 846,763 | 4,412,533 | /8 | 551,567 | 57,745 | 4,423 |
| 9 | 2024 | | 837,246 | 4,367,318 | /9 | 485,258 | | 932,678 | 4,450,204 | /9 | 494,467 | | 874,819 | 4,847,978 | /9 | 538,664 | 53,407 | 9,210 |
| 10 | 2025 | | 866,308 | 4,766,364 | /10 | 476,636 | | 971,905 | 4,897,891 | /10 | 489,789 | | 914,045 | 5,269,013 | /10 | 526,901 | 50,265 | 13,153 |
| 11 | 2026 | | 998,719 | 5,192,089 | /11 | 472,008 | | 1,105,141 | 5,368,980 | /11 | 488,089 | | 1,047,281 | 5,715,438 | /11 | 519,585 | 47,577 | 16,081 |
| 12 | 2027 | | 1,026,259 | 5,596,923 | /12 | 466,410 | | 1,137,164 | 5,817,564 | /12 | 484,797 | | 1,079,304 | 6,141,198 | /12 | 511,766 | 45,356 | 18,387 |
| 13 | 2028 | | 1,058,339 | 5,983,273 | /13 | 460,252 | | 1,144,748 | 6,235,457 | /13 | 479,651 | | 1,086,888 | 6,537,969 | /13 | 502,921 | 42,669 | 19,399 |
| 14 | 2029 | DFGD Installed | 1,212,734 | 6,392,964 | /14 | 456,640 | | 1,132,735 | 6,618,123 | /14 | 472,723 | | 1,074,876 | 6,901,088 | /14 | 492,935 | 36,295 | 16,083 |
| 15 | 2030 | | 1,219,417 | 6,774,186 | /15 | 451,612 | | 1,106,997 | 6,964,199 | /15 | 464,280 | | 1,097,045 | 7,244,053 | /15 | 482,937 | 31,324 | 12,668 |
| 16 | 2031 | | 1,269,136 | 7,141,357 | /16 | 446,335 | | 1,154,607 | 7,298,236 | /16 | 456,140 | | 1,144,654 | 7,575,211 | /16 | 473,451 | 27,116 | 9,805 |
| 17 | 2032 | | 1,232,143 | 7,471,237 | /17 | 439,485 | | 1,111,992 | 7,595,949 | /17 | 446,821 | | 1,102,040 | 7,870,259 | /17 | 462,956 | 23,472 | 7,336 |
| 18 | 2033 | | 1,273,573 | 7,786,777 | /18 | 432,599 | | 1,147,592 | 7,880,276 | /18 | 437,793 | | 1,137,640 | 8,152,120 | /18 | 452,896 | 20,297 | 5,194 |
| 19 | 2034 | | 1,411,013 | 8,110,294 | /19 | 426,858 | | 1,267,035 | 8,170,781 | /19 | 430,041 | | 1,257,083 | 8,440,344 | /19 | 444,229 | 17,371 | 3,184 |
| 20 | 2035 | | 1,484,012 | 8,425,169 | /20 | 421,258 | | 1,344,199 | 8,455,991 | /20 | 422,800 | | 1,334,247 | 8,723,442 | /20 | 436,172 | 14,914 | 1,541 |
| 21 | 2036 | | 2,132,242 | 8,843,840 | /21 | 421,135 | | 1,999,246 | 8,848,547 | /21 | 421,359 | | 1,989,294 | 9,114,044 | /21 | 434,002 | 12,867 | 224 |
| 22 | 2037 | | 2,360,189 | 9,272,702 | /22 | 421,486 | | 2,216,065 | 9,251,221 | /22 | 420,510 | | 2,206,113 | 9,514,909 | /22 | 432,496 | 11,009 | (976) |
| 23 | 2038 | | 3,007,263 | 9,778,384 | /23 | 425,147 | | 2,960,441 | 9,749,029 | /23 | 423,871 | | 2,950,489 | 10,011,044 | /23 | 435,263 | 10,116 | (1,276) |
| 24 | 2039 | | 3,057,666 | 10,254,191 | /24 | 427,258 | | 3,010,710 | 10,217,529 | /24 | 425,730 | | 3,000,757 | 10,477,996 | /24 | 436,583 | 9,325 | (1,528) |
| 25 | 2040 | | 3,107,043 | 10,701,619 | /25 | 428,065 | | 3,043,137 | 10,655,755 | /25 | 426,230 | | 3,033,185 | 10,914,788 | /25 | 436,592 | 8,527 | (1,835) |
| 26 | 2041 | | 3,153,777 | 11,121,902 | /26 | 427,765 | | 3,096,380 | 11,068,389 | /26 | 425,707 | | 3,086,427 | 11,326,096 | /26 | 435,619 | 7,854 | (2,058) |
| 27 | 2042 | | 3,223,194 | 11,519,397 | /27 | 426,644 | | 3,159,894 | 11,458,078 | /27 | 424,373 | | 3,149,941 | 11,714,558 | /27 | 433,873 | 7,228 | (2,271) |
| 28 | 2043 | | 3,284,778 | 11,894,273 | /28 | 424,795 | | 3,219,131 | 11,825,462 | /28 | 422,338 | | 3,209,179 | 12,080,806 | /28 | 431,457 | 6,662 | (2,458) |
| 29 | 2044 | | 3,336,984 | 12,246,701 | /29 | 422,300 | | 3,255,197 | 12,169,252 | /29 | 419,629 | | 3,245,245 | 12,423,545 | /29 | 428,398 | 6,098 | (2,671) |
| 30 | 2045 | | 3,402,902 | 12,579,284 | /30 | 419,309 | | 3,331,461 | 12,494,853 | /30 | 416,495 | | 3,321,509 | 12,748,173 | /30 | 424,939 | 5,630 | (2,814) |
| 36.3 | w/ End-Eff | | | 16,152,898 | /36.3 | 444,983 | | | 16,236,528 | /36.3 | 447,287 | | | 16,475,367 | /36.3 | 453,867 | 8,883 | 2,304 |

**Indiana Michigan Power Co.**
Rockport Unit 2 Disposition Analysis
*Long-Term, Life Cycle Economics (2016-2045, with end-effects)*

***COMPARISON OR RELATIVE*** **Cumulative Present Worth (CPW) of I&M Net Utility "Generation" Costs (2016 $)**

**(COST / <SAVINGS> )**

Rockport Unit 2 SCR CPCN Filing

*versus*

I&M 2015 IRP

| L/T Commodity Pricing Scenarios | **RK U2 SCR CPCN OPTION #1B** *over* **OPTION #1A** [A] | *2015 IRP* *"Fleet Modification"* *over* *"Steady State"* *"As-Filed"* [B] | **RK U2 SCR CPCN OPTION #2** *over* **OPTION #1A** [A] | *2015 IRP* *"Fleet Modification w/ NO RK U2 SCR"* *over* *"Steady State"* *"As-Filed"* [B] | **RK U2 SCR CPCN OPTION #2** *over* **OPTION #1B** [C] | *2015 IRP* *"Fleet Modification w/ NO RK U2 SCR"* *over* *"Fleet Modification"* *"As-Filed"* [B] |
|---|---|---|---|---|---|---|
| "BASE" Forecast | **84** | **174** | **322** | ~~**639**~~ | **239** | ~~**465**~~ |
| | | | | *"As-Corrected"* **434** | | *"As-Corrected"* **260** |
| *Alternative Scenario Pricing...* | | | | | | |
| "Lower Band" | (131) | (19) | 99 | Analysis performed under "BASE" pricing only in 2015 IRP | 230 | Analysis performed under "BASE" pricing only in 2015 IRP |
| "Higher Band" | 349 | 331 | 621 | | 272 | |
| "No Carbon" Price | 233 | 333 | 485 | | 252 | |
| "High Carbon" Price | (90) | 5 | 142 | | 233 | |

[A] Attachment SCW-4-1
[B] I&M 2015 IRP; Table 22 (pg. 120)
[C] Attachment SCW-4-2

*Additional Notes:*
- o All scenario pricing alternatives (excluding "No $CO_2$") assume carbon/$CO_2$ pricing is effective in 2022
- o Option #1A / "Steady State" assume: RK U2 retrofitted w/ SCR (12/19) & DFGD (12/28)
- o Option #1B / "Fleet Modification" assume: RK U2 retrofit for SCR only (12/19) then unit returned to Lessor @ 12/2022 and replaced
- o Option #2 / "Fleet Modification w/ NO SCR Return assumes: No SCR and unit returned to Lessor 12/2019 and replaced
- o Each Rockport unit reflects I&M's 50% (650-MW) Ownership share; plus 70% (455-MW) Purch.Entitlement from affiliate AEP Generating Cos.' 50% ownership share

Indiana Michigan Power Company
Attachment SCW-6