TESTIMONY OF OUCC WITNESS EDWARD T. RUTTER
CAUSE NO. 44967
<u>INDIANA MICHIGAN POWER COMPANY</u>

I. INTRODUCTION

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

A: My name is Edward T. Rutter. I am employed by the Indiana Office of Utility Consumer Counselor ("OUCC") as a Chief Technical Advisor in the Energy Resources Division. My business address is 115 West Washington St., Suite 1500 South Tower, Indianapolis, Indiana 46204. My educational background and professional experience are detailed in Appendix ETR-1 attached to this testimony.

Q: What is the purpose of your direct testimony?

A: The purpose of my testimony is to demonstrate to the Indiana Utility Regulatory Commission ("Commission") that Indiana Michigan Power Company's ("I&M") request to revise its depreciation accrual rates for electric plant in service should be denied for Steam Production Plant and Distribution Plant. My testimony raises issues relative to Rockport Unit 1's early retirement, Rockport Unit 2's lease termination, the impact on the depreciation period for the Dry Sorbent Injection ("DSI") and Selective Catalytic Reduction ("SCR") investments, and the transitioning to Advanced Metering Infrastructure ("AMI") meters.

I also demonstrate that I&M's request to continue the current amount of annual ratepayer contributions to the nuclear decommissioning trust fund is unnecessary and unreasonable. I discuss the growth of the fund and provide documents from the Nuclear Regulatory Commission ("NRC") that indicate ongoing contributions to I&M's nuclear decommissioning trust fund are not required.

II. DEPRECIATION ANNUAL ACCRUAL

Q: Does the OUCC object to I&M's adjustment to the remaining useful life of Rockport Unit 1 and the resultant proposed depreciation rate?

A: Yes. I&M operates the two Rockport coal-fired generation units that provide baseload capacity. Unit 1 was placed in service in 1984 and was expected to retire in 2044, resulting in a 60 year life. The 2044 retirement date was adopted in the prior two depreciation studies and was based on utility plant in service on December 31, 2004 and December 31, 2010.

I&M is seeking in this Cause to accelerate its depreciation rate for Rockport Unit 1 to reflect depreciation through 2028. Petitioner's witness Mr. Toby L. Thomas states "[a]s the role of coal has changed, a more realistic date through which Rockport Unit 1 can be expected to be in operation with any reasonable degree of certainty is December 2028".[1] The OUCC recognizes that the role of coal has changed, but I&M's IRP has not – it still includes Rockport Unit 1 through 2044. Until I&M revises and updates its Integrated Resource Plan ("IRP") reflecting the Rockport Unit 1's retirement and addresses the expected load requirements and required replacement generation, any change to the expected remaining life of Rockport Unit 1 is premature.

[1] Pre-filed direct testimony of I&M witness Toby L. Thomas, page 23, lines 9 – 12.

Q: What treatment is the OUCC recommending the Commission adopt relative to Rockport Unit 1's depreciation rate?

A: The OUCC recommends the Commission disallow I&M's proposed change in the estimated retirement, for depreciation rate purposes, of Rockport Unit 1 from 2044 to 2028. Further, we recommend that I&M file an amendment to the depreciation rates that is consistent with the retirement date adopted and replacement generation resulting from I&M's next required IRP due in November, 2018. We believe this recommendation is consistent with the pre-filed direct testimony of I&M witness Thomas where he testifies: "As we move forward, the Company will continue to evaluate the viability of the Rockport Plant against other potential solutions that could meet our customers' needs. I&M will keep the Commission informed on this important matter, including in its next Integrated Resource Plan."[2]

Q: Does the OUCC also recommend a no change be made to the depreciation rate for the Rockport Unit 1 DSI system placed in service in 2015 and the SCR system expected to be completed in 2017?

A: Yes. The OUCC is recommending ~~no change be made to the currently approved~~ the same 28 years be used to calculate depreciation rates for the Rockport Unit 1 DSI and SCR. It is premature to make any changes to the Rockport Unit 1 asset depreciation rates until the next IRP is filed.

Q: Does the OUCC support I&M's proposed change to the Rockport Unit 2 DSI depreciation rate?

A: No. I&M is proposing to depreciate the Rockport Unit 2 DSI project through 2022 consistent with terminating the operating lease for Unit 2. In Cause No. 44871, I&M's SCR Certificate of Public Convenience and Necessity ("CPCN") filing, the

[2] Pre-filed direct testimony of I&M witness Toby L. Thomas, page 22, lines 4 – 7.

OUCC recommended that the Rockport Unit 2 lease not be terminated prior to the scheduled lease termination and to base any decision to extend the lease on the results of the next IRP. Mr. Thomas appears to confirm the OUCC's recommendation in Cause No. 44871 when he testifies, "In addition, the Company will address the replacement of Rockport Unit 2 energy and capacity in its next Integrated Resource Plan."[3]

Q: Are you recommending any additional adjustments to the depreciation rates recommended by I&M for Rockport Unit 1?

A: Yes. As a result of my review of I&M witnesses' direct testimony, workpapers and I&M's responses to data requests, I recommend disallowing the contingency costs included in the conceptual demolition cost estimates for Rockport Unit 1 included in the "Conceptual Demolition Cost Estimate" for Rockport Unit 1.

The Sargent & Lundy report included a contingency allowance of $17,996,000 for estimates of the scrap value, material, labor, indirect costs and subcontractor costs and a contingency of $75,000 related to asbestos removal. Based on the description of how the estimates were performed and the information considered, the inclusion of a contingency for developing a future net salvage value is superfluous for developing estimated depreciation rates for long lived assets. A contingency addition to an estimate is traditionally designed to cover costs that are indeterminable, unpredictable and/or unforeseen at present. In developing the decommissioning costs for Rockport Unit 1, I&M retained the services of Sargent & Lundy to prepare a Conceptual Demolition Cost Estimate. The report generated

[3] Pre-filed direct testimony of I&M witness Toby L. Thomas, page 22, lines 16 – 18.

by Sargent & Lundy for Rockport Unit 1 includes cost detail for all components of the gross demolition cost estimate (including gross salvage credits and any other benefits) for Rockport Unit 1 based on updated pricing and specific scope additions/deletions. There is no need to include a contingency factor since the scope has been updated and the pricing is current. There is no indeterminable, unpredictable or unforeseen scope change now to support applying a contingency factor for an asset scheduled to retire in 2044.

Q: Have you prepared attachments that reflect your proposed adjustments to Rockport Unit 1's depreciation annual accrual and rate?

A: Yes. Attachment ETR-1, pages 1 and 2 of 2, calculates the annual accrual and the annual accrual rate for Rockport Unit 1 based on the recommendations I provide in my testimony.

Attachment ETR-1 recomputes the annual accrual and annual accrual rate. By reference to Attachment ETR-1, the resulting annual accrual for Rockport Unit 1 is $22,055,932 and the annual accrual rate is 2.44%. This is in contrast to the $67,583,847 annual accrual of and composite depreciation rate of 7.47% proposed by I&M.[4] The recommended adjustment is a $45,527,915 decrease in the annual accrual.

Q: Does the OUCC recommend the Commission accept I&M's proposed change to the existing depreciation rate for Account 370 Meters?

A: No. I&M is proposing to transition from Automatic Meter Reading ("AMR") meters to Advanced Metering Infrastructure ("AMI") meters across its service

[4] Attachment JAC-1, page 25 of 35.

territory over the next five years.[5] In reviewing I&M's pre-filed direct testimony, supporting attachments, and workpapers, I&M has provided no meter replacement plan or any document that shows the estimated costs to support the proposed transition from AMR meters to AMI meters. It is premature to change the depreciation rate for a transition plan that has not been fully developed. There is no way to determine if the transition to AMI meters is beneficial to ratepayers nor any evidence to support ratepayers reimbursing I&M for investments in two different metering technologies where only one will be used and useful in the delivery of electric service to customers.

Q: Are you recommending any additional adjustments to I&M's proposed depreciation rates for Account 370 Meters?

A: Yes. In my review of the depreciable plant in service original cost at December 31, 2016for Account 370 Meters, I determined the allocated accumulated depreciation balance is inadequate for a group of assets to be depreciated over twenty five (25) years as established in Cause No. 44075.[6] Assuming the AMR meters were placed in service five years ago,[7] the accumulated depreciation included in I&M's case does not reflect a 25 year asset life.

I have prepared Attachment ~~ETR-3~~ ETR-2, p. 2 of 2 to estimate the accumulated depreciation for Account 370 Meters based on the in-service date provided in Mr. Thomas's testimony. The estimated accumulated depreciation I used in developing the recommended annual accrual is $16,441,645.

[5] Pre-filed direct testimony of I&M witness Jason A. Cash, page 11, lines 18 – 19.
[6] Pre-filed direct testimony of I&M witness Jason A. Cash, page 10, lines 19 – 20.
[7] Pre-filed direct testimony of I&M witness Toby L. Thomas, page 12, lines 21 – 22.

Q: **Have you prepared an attachment that recalculates the depreciation rate, accrual for Account 370 Meters, and the composite depreciation rate for Distribution Plant?** ETR-2, p. 1 of 2, Row 370.0

A: Yes. Attachment ~~ETR-2~~ calculates my recommended depreciation rate for Account 370 Meters. The calculated depreciation rate for Account 370 meters is 4.95% as opposed to the I&M proposed 23.9% depreciation rate. The resulting Depreciation Plant composite rate I recommend is 3.49% as opposed to I&M's proposed 4.40% composite depreciation rate for Account 370. The result of my calculations is a recommended reduction in I&M's proposed annual accrual for Distribution Plant of $83,007,393 to $65,800,668. This results in an annual difference of $17,206,725.

III. NUCLEAR DECOMMISSIONING TRUST

Q: **Have you reviewed I&M's position on the Nuclear Decommissioning Trust?**

A: Yes. I reviewed the pre-filed direct testimony and respective workpapers of I&M witnesses Aaron L. Hill and Roderick K. Knight. I also reviewed public documents available on the United States Nuclear Regulatory Commission ("NRC") website, including those for both D.C. Cook units and general audit reports relative to the Nuclear Decommissioning Trust Funds ("DTF"). I have attached to my testimony the following documents gathered from the NRC website:

- 2015 DECOMMISSIONING FUNDING STATUS REPORT
  - Power Reactor Decommissioning Funding Assurance as of December 31, 2014, Attachment ETR-5
- Letter dated March 21, 2017, from I&M's witness, Q. Shane Lies, to the NRC; D.C. Cook Nuclear Plant Units 1 and 2; Decommissioning Funding Status Report, Attachment ETR-6

- Policy Issue (Information); dated September 28, 2015; Summary Findings Resulting From the Staff Review of the 2015 Decommissioning Funding Status Reports for Operating Power Reactor Licensees, Attachment ETR-7

Q. Based on the information provided by I&M witnesses Hill and Knight in their direct testimony, responses to OUCC data requests, and the information available on the NRC website, does the OUCC support continuing the $4,000,000 annual contribution to the DTF?

A: No. Continuation of the $4,000,000 annual contribution to the DTF is not necessary to meet the decommissioning requirements beginning in 2034 for Cook Unit 1 and 2037 for Cook Unit 2.

Q. What is the estimated cost of decommissioning D.C. Cook Units 1 and 2?

A. Petitioner's Attachment RK-1 pages 30 - 31 of 50, including Table 9.1, estimates the total cost for the decommissioning scenario proposed by I&M at approximately $1.6 million fixed and $4.9 million annually. There is an additional cost estimate of approximately $57.1 million for the eventual decontamination and removal of the Independent Spent Fuel Storage Installation ("ISFSI"). The total estimated decommissioning costs at the end of the licensing periods (Unit 1 October 25, 2034 and Unit 2 December 23, 2037) is approximately $1.69 billion.

By reference to Attachment ETR-5, the NRC's 2015 DECOMMISSIONING FUNDING STATUS REPORT, the NRC Minimum or Site Specific Cost Estimate is $517,059,935 for Unit 1 and $521,654,470 for Unit 2, a total of $1,038,714,406.

Q. What is the estimated balance of the Total Cook Nuclear Plant Nuclear Decommissioning Trust at December 31, 2016?

A. The estimated Total Cook Nuclear Plant Decommissioning Plant balance is $1,804,116,646 provided in I&M Workpaper, WP-ALH-6.

Q. What is the estimated Indiana portion of the market value at December 31, 2016 and 2018?

A. The existing Indiana market value for the DTF at December 31, 2016 is $1,390,697,590. That balance is estimated to grow to $1,602,477,933 at December 31, 2018.[8]

Q. Has the OUCC prepared a schedule estimating what the Indiana market and liquidation value will be a December 31, 2037?

Yes. When we assume continuation of the $4,000,000 annual contribution by Indiana ratepayers at the annual investment earnings rate assumed by I&M and the estimated qualified tax rate, the market value of the fund grows to $6,002,504,033 with a liquidation value of $4,993,664,990 at December 31, 2037.[9]

If we assume that the annual contributions made by the Indiana ratepayers were to cease after December 31, 2018 and we assume the same annual investment earnings rate and qualified tax rate, the market value of the fund grows to $5,899,184,835 with a liquidation value of $4,895,809,632 at December 31, 2037.[10]

By the NRC's own standards, the liquidated value of the DTF under either scenario at December 31, 2037 is more than sufficient to meet the nuclear decommissioning requirements for Cook Units 1 & 2.

Q. Is there data available from the NRC website that also develops the projected DTF balance prior to decommissioning?

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[8] WP-ALH-6.
[9] Attachment ETR-3, pages 1 & 2 of 2.
[10] Attachment ETR-4, pages 1 & 2 of 2.

A. Yes, referring to Attachment ETR-5, the projected DTF balance prior to decommissioning is $874,634,252 for D.C. Cook Unit 1 and $865,429,482 for D.C. Cook unit 2, for a total D.C. Cook nuclear power plant of $1,740,063,374.

Q. Based on the liquidated value of the Indiana portion of the estimated DTF at December 31, 2037 or the estimates included on the 2015 Decommissioning Funding Status Report available on the NRC website and included as Attachment ETR-5, is there a need to continue the $4,000,000 contribution to the DTF after the test year end, December 31, 2018?

A. No. Under either estimate, there are sufficient funds available as of December 31, 2037 to support a discontinuation of the $4,000,000 annual contribution by Indiana ratepayers to the DTF.

Q. On page 3, lines 25 and 26 and page 4 lines 1 – 5, I&M witness Hill suggests that continuing the $4,000,000 annual contribution to the DTF ensures the customers that use the power generated by D.C. Cook Units 1 and 2 today will pay for the decommissioning of D.C. Cook Units 1 and 2 in the future. Does the OUCC agree with that proposition?

A. If the D.C. Cook Units are operating through 2034 and 2037 respectively, then customers during those periods would be receiving power from the two Cook units. However, that point does not outweigh the harm of requiring customers to continually fund a $4,000,000 annual contribution that the NRC's findings indicate is unnecessary. If the liquidated value of the DTF is sufficient without further contributions, asking customers to continue to contribute to the fund is unnecessarily harmful.

Further, if the DTF is over-funded, any refund would go to ratepayers that may not have contributed to the DTF during the remaining life of the Units. Either circumstance is unacceptable.

IV. RECOMMENDATIONS

Q: What are you recommending to the Commission in this proceeding?

A: I am recommending the Commission adopt the following:

- An annual depreciation accrual rate of 2.44% for Rockport Unit 1 for purposes of developing test year depreciation expense.
- An annual depreciation accrual rate for Account 370 Meters of 4.95% and a distribution Plant composite depreciation rate of 3.49%.
    - For purposes of developing test year rate base and depreciation, adopt an accumulated depreciation for Account 370 Meters at December 31, 2016 in the amount of $16,441,645.
- Discontinue the annual contribution of $4,000,000 paid by ratepayers to the nuclear decommissioning fund after December 31, 2018.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX TO TESTIMONY OF
OUCC WITNESS EDWARD T. RUTTER

Q: Please describe your educational background and experience.

A: I am a graduate of Drexel University in Philadelphia, PA, with a Bachelor of Science degree in Business Administration. I was employed by South Jersey Gas Company as an accountant responsible for coordinating annual budgets, preparing preliminary monthly, quarterly, annual and historical financial statements, assisting in preparation of annual reports to shareholders, all SEC filings, state and local tax filings, all FPC/FERC reporting, plant accounting, accounts payable, depreciation schedules and payroll. Once the public utility holding company was formed, South Jersey Industries, Inc., I continued to be responsible for accounting as well as for developing the consolidated financial statements and those of the various subsidiary companies including South Jersey Gas Company, Southern Counties Land Company, Jessie S. Morie Industrial Sand Company, and SJI LNG Company.

I left South Jersey Industries, Inc. and took a position with Associated Utility Services Inc. (AUS), a consulting firm specializing in utility rate regulation including rate of return, revenue requirement, purchased gas adjustment clauses, fuel adjustment clauses, revenue requirement development and valuation of regulated entities.

On leaving AUS, I worked as an independent consultant in the public utility area as well as telecommunications including cable television (CATV). I joined the OUCC in December 2012 as a utility analyst.

Q: Have you previously testified before the Indiana Utility Regulatory Commission?

A: I have previously testified before the Indiana Utility Regulatory Commission (Commission) in Cause Nos. 44311, 44331, 44339, 44363, 44370, 44418, 44429, 44446, 44478, 44486, 44495, 44497, 44526, 44540, 44542, 44576, 44602, 44403, 44634, 44645, 44688, 44794, 44765, 44835, 44841, 44871, 44872, 44910 plus 43827, 44781, 43955 and 44927 DSM dockets and several sub-dockets.. I have also testified before the regulatory commissions in the states of New Jersey, Delaware, Maryland, Pennsylvania, New York, Connecticut, Georgia, Florida, North Carolina, Ohio, Oklahoma, Virginia and Wisconsin. In addition to the states mentioned, I submitted testimony before the utility regulatory commissions in the Commonwealth of Puerto Rico and the U.S. Virgin Islands. I have also testified as an independent consultant on behalf of the U.S. Internal Revenue Service in Federal Tax Court, New York jurisdiction.

INDIANA MICHIGAN POWER COMPANY
CALCULATION OF DEPRECIATION RATES
BASED ON DEPRECIABLE PLANT IN SERVICE AT DECEMBER 31, 2016
ADJUSTED

ACCOUNT NUMBER	ACCCOUNT	ORIGINAL COST	NET SALVAGE RATIO	COST TO BE RECOVERED	ALLOCATED ACCUMULATED DEPRECIATION	REMAINING TO BE RECOVERED	AVERAGE REMAINING LIFE	RECOMMENDED ACCRUAL AMOUNT	RECOMMENDED ACCRUAL %
	STEAM PRODUCTION PLANT:		(a)				(b)		
	ROCKPORT UNIT 1								
311.0	STRUCTURES & IMPROVEMENTS	$99,017,726	1.07	$105,948,967	$32,363,830	$73,585,137	28	$2,628,041	2.65%
312.0	BOILER PLANT EQUIPMENT	570,381,956	1.07	610,308,693	140,727,157	469,581,536	28	16,770,769	2.94%
314.0	TURBOGENERATOR UNITS	96,471,667	1.07	103,224,684	29,567,354	73,657,330	28	2,630,619	2.73%
315.0	ACCESSORY ELECTRICAL EQUIPMENT	61,506,149	1.07	65,811,579	20,418,673	45,392,906	28	1,621,175	2.64%
316.0	MISCELANEOUS POWER PLANT EQUIPMENT	16,195,891	1.07	17,329,603	5,055,096	12,274,507	28	438,375	2.71%
	TOTAL	843,573,389	1.07	902,623,526	228,132,110	674,491,416	28	24,088,979	2.86%
	ROCKPORT ACI								
312.0	BOILER PLANT EQUIPMENT	11,817,734	1.07	12,644,975	5,572,354	7,072,621	28	252,594	2.14%
	TOTAL								
	ROCKPORT UNIT 1 DSI								
311.0	STRUCTURES & IMPROVEMENTS	2,904,445	1.07	3,107,756	576,224	2,531,532	28	90,412	3.11%
312.0	BOILER PLANT EQUIPMENT	46,248,904	1.07	49,486,327	5,736,130	43,750,197	28	1,562,507	3.38%
	TOTAL	49,153,349	1.07	52,594,083	6,312,354	46,281,729	28	1,652,919	3.36%
	TOTAL ROCKPORT UNIT 1	$904,544,472		$967,862,585	$240,016,818	$727,845,767	28	$25,994,492	2.87%
	AS FILED ATTACHMENT JAC-1, PAGE 25 OF 35	$904,544,472						$67,583,847	7.47%

NOTES:
(a) DEVELOPED ON ATTACHMENT ETR-1 PAGE 2 OF 2
(b) ASSUMED UNIT IN SERVICE THROUGH 2044

INDIANA MICHIGAN POWER CALCULATION
DEVELOPMENT OF NET SALVAGE RATIO
BASED ON DEPRECIABLE PLANT IN SERVICE AT DECEMBER 31, 2016
ADJUSTED

DESCRIPTION	TOTAL COST AS FILED $	TOTAL COST ADJUSTED $
ROCKPORT UNIT 1		
COST ESTIMATE RESULTS SUMMARY:		
DEMOLITION COST	$72,559,096	$72,559,096
SCRAP VALUE	(13,553,935)	(13,553,935)
DIRECT COST SUBTOTAL	59,005,161	59,005,161
INDIRECT COST	7,256,000	7,256,000
CONTINGENCY COST	17,996,000	0
ESCALATION COST	0	0
SUB-TOTAL DEMOLITION COST	84,257,161	66,261,161
ASBESTOS REMOVAL:		
DEMOLITION COST	338,366	338,366
SCRAP VALUE	0	0
DIRECT COST SUBTOTAL	338,366	338,366
INDIRECT COST	34,000	34,000
CONTINGENCY COST	75,000	0
ESCALATION COST	0	0
SUB-TOTAL ASBESTOS REMOVAL	447,366	372,366
TOTAL ROCKPORT UNIT 1	$84,704,527	$66,633,527
TOTAL ROCKPORT UNIT ORIGINAL COST @ DECEMBER 31, 2016 (a)	$904,544,472	$904,544,472
NET SALVAGE RATIO	1.09	1.07

NOTES:
(a) DEVELOPED ON ATTACHMENT ETR-1, PAGE 1 OF 2 and
and Petitioner's Witness Mr. Cash's Attachment JAC-1 at page 25.

INDIANA MICHIGAN POWER COMPANY
CALCULATION OF DEPRECIATION RATES
BASED ON DEPRECIABLE PLANT IN SERVICE AT DECEMBER 31, 2016
ADJUSTED

ACCOUNT NUMBER	ACCCOUNT	ORIGINAL COST	NET SALVAGE RATIO	COST TO BE RECOVERED	ALLOCATED ACCUMULATED DEPRECIATION	REMAINING TO BE RECOVERED	AVERAGE REMAINING LIFE	RECOMMENDED ACCRUAL AMOUNT	RECOMMENDED ACCRUAL %
	DISTRIBUTION PLANT"						(b)		
360.1	LAND RIGHTS	$13,770,217	1.00	$13,770,217	$3,252,741	$10,517,476	51.79	$203,079	1.47%
361.0	STRUCTURES & IMPROVEMENTS	14,811,177	1.10	16,292,295	3,243,351	13,048,944	62.15	209,959	1.42%
362.0	STATION EQUIPMENT	244,926,449	1.03	252,274,242	41,983,929	210,290,313	42.84	4,908,737	2.00%
363.0	STORAGE BATTERY EQUIPMENT	5,488,900	1.00	5,488,900	3,188,728	2,300,172	7.50	306,690	5.59%
364.0	POLES, TOWERS & FIXTURES	259,353,877	1.78	461,649,901	126,510,711	335,139,190	25.22	13,288,628	5.12%
365.0	OVERHEAD CONDUCTOR & DEVICES	416,967,574	1.10	458,664,331	94,879,526	363,784,805	27.13	13,408,950	3.22%
366.0	UNDERGROUND CONDUIT	86,716,318	1.00	86,716,318	21,942,392	64,773,926	41.46	1,562,323	1.80%
367.0	UNDERGROUND CONDUCTOR	228,330,495	1.00	228,330,495	50,938,431	177,392,064	40.40	4,390,893	1.92%
368.0	LINE TRANSFORMERS	306,878,569	1.06	325,291,283	147,148,606	178,142,677	12.22	14,577,960	4.75%
369.0	SERVICES	172,328,184	1.20	206,793,821	66,294,766	140,499,055	27.52	5,105,344	2.96%
370.0	METERS (a)	91,342,472	1.22	111,437,816	16,441,645	94,996,171	21.00	4,523,627	4.95%
371.0	INSTALLATIONS ON CUSTS. PREM.	26,350,180	1.23	32,410,721	12,826,308	19,584,413	8.57	2,285,229	8.67%
373.0	STREET LIGHTING & SIGNAL SYSTEMS	20,562,372	1.12	23,029,857	14,631,182	8,398,675	8.16	1,029,249	5.01%
	TOTAL DISTRIBUTION PLANT	$1,887,826,784		$2,222,150,197	$603,282,316	$1,618,867,881		$65,800,668	3.49%

NOTES:

(a) ASSUMED METERS DEPRECIATED AT THE CURRENTLY APPROVED RATE OF 4.00% AND ESTIMATED ACCUMULATED DEPRECIATION

ACCOUNT NUMBER	ACCOUNT	ADDITIONS TO ELECTRIC PLANT 2011	ADDITIONS TO ELECTRIC PLANT 2012	ADDITIONS TO ELECTRIC PLANT 2013	ADDITIONS TO ELECTRIC PLANT 2014	ADDITIONS TO ELECTRIC PLANT 2015	ADDITIONS TO ELECTRIC PLANT 2016
370	METERS:						
370	BALANCE @ 1/1	$0	$30,447,491	$60,894,982	$91,342,472	$91,342,472	$91,342,472
370	ADDITIONS	30,447,491	30,447,491	30,447,490	0	0	0
370	RETIREMENTS	0	0	0	0	0	0
370	BALANCE @ 12/31	$30,447,491	$60,894,982	$91,342,472	$91,342,472	$91,342,472	$91,342,472
370	DEPRECIATION RATE	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
	DEPRECIATION EXPENSE:						
370	ANNUAL PLANT ADDITIONS	$608,950	$608,950	$608,950	$0	$0	$0
370	FULL YEAR BEGINNING BALANCE	0	1,217,900	2,435,799	3,653,699	3,653,699	3,653,699
370	TOTAL ANNUAL DEPRECIATION	$608,950	$1,826,849	$3,044,749	$3,653,699	$3,653,699	$3,653,699
370	ACCUMULATED DEPRECIATION	$608,950	$2,435,799	$5,480,548	$9,134,247	$12,787,946	$16,441,645

INDIANA MICHIGAN POWER COMPANY
DEVELOPMENT OF ESTIMATED NUCLEAR DECOMMISSIONING TRUST
AS OF DECEMBER 31, 2017 - 2037

DESCRIPTION	MARKET VALUE $	TAX BASIS VALUE $	UNREALIZED GAIN/LOSS $	TAXES DUE UNREALIZED GAINS $	LIQUIDATION VALUE $
AT DECEMBER 2016	$1,390,697,559	$874,308,818	$516,388,741	$103,277,748	$1,287,419,811
INDIANA CONTRIBUTIONS 2017	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	98,281,246	0	98,281,246	19,656,249	78,624,997
AT DECEMBER 2017	1,492,978,805	878,308,818	614,669,987	122,933,997	1,370,044,808
INDIANA CONTRIBUTIONS 2018	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	105,499,129	0	105,499,129	21,099,826	84,399,303
AT DECEMBER 2018	1,602,477,934	882,308,818	720,169,116	144,033,823	1,458,444,111
INDIANA CONTRIBUTIONS 2019	0	0	0	0	0
PROJECTED EARNINGS	113,775,933	0	113,775,933	22,755,187	91,020,747
AT DECEMBER 2019	1,716,253,867	882,308,818	833,945,049	166,789,010	1,549,464,857
INDIANA CONTRIBUTIONS 2020	0	0	0	0	0
PROJECTED EARNINGS	121,854,025	0	121,854,025	24,370,805	97,483,220
AT DECEMBER 2020	1,838,107,892	882,308,818	955,799,074	191,159,815	1,646,948,077
INDIANA CONTRIBUTIONS 2021	0	0	0	0	0
PROJECTED EARNINGS	130,505,660	0	130,505,660	26,101,132	104,404,528
AT DECEMBER 2021	1,968,613,552	882,308,818	1,086,304,734	217,260,947	1,751,352,605
INDIANA CONTRIBUTIONS 2022	0	0	0	0	0
PROJECTED EARNINGS	139,771,562	0	139,771,562	27,954,312	111,817,250
AT DECEMBER 2022	2,108,385,114	882,308,818	1,226,076,296	245,215,259	1,863,169,855
INDIANA CONTRIBUTIONS 2023	0	0	0	0	0
PROJECTED EARNINGS	149,695,343	0	149,695,343	29,939,069	119,756,274
AT DECEMBER 2023	2,258,080,458	882,308,818	1,375,771,640	275,154,328	1,982,926,130
INDIANA CONTRIBUTIONS 2024	0	0	0	0	0
PROJECTED EARNINGS	160,323,712	0	160,323,712	32,064,742	128,258,970
AT DECEMBER 2024	2,418,404,170	882,308,818	1,536,095,352	307,219,070	2,111,185,100
INDIANA CONTRIBUTIONS 2025	0	0	0	0	0
PROJECTED EARNINGS	171,706,696	0	171,706,696	34,341,339	137,365,357
AT DECEMBER 2025	2,590,110,866	882,308,818	1,707,802,048	341,560,410	2,248,550,456
INDIANA CONTRIBUTIONS 2026	0	0	0	0	0
PROJECTED EARNINGS	183,897,871	0	183,897,871	36,779,574	147,118,297
AT DECEMBER 2026	2,774,008,738	882,308,818	1,891,699,920	378,339,984	2,395,668,754
INDIANA CONTRIBUTIONS 2027	0	0	0	0	0
PROJECTED EARNINGS	196,954,620	0	196,954,620	39,390,924	157,563,696
AT DECEMBER 2027	2,970,963,358	882,308,818	2,088,654,540	417,730,908	2,553,232,450

INDIANA MICHIGAN POWER COMPANY
DEVELOPMENT OF ESTIMATED NUCLEAR DECOMMISSIONING TRUST
BALANCE AS OF DECEMBER 31, 2017 - 2037

DESCRIPTION	MARKET VALUE $	TAX BASIS VALUE $	UNREALIZED GAIN/LOSS $	TAXES DUE UNREALIZED GAINS $	LIQUIDATION VALUE $
AT DECEMBER 2027	$2,970,963,358	$882,308,818	$2,088,654,540	$417,730,908	$2,553,232,450
INDIANA CONTRIBUTIONS 2028	0	0	0	0	0
PROJECTED EARNINGS	210,938,398	0	210,938,398	42,187,680	168,750,719
AT DECEMBER 2028	3,181,901,756	882,308,818	2,299,592,938	459,918,588	2,721,983,169
INDIANA CONTRIBUTIONS 2029	0	0	0	0	0
PROJECTED EARNINGS	225,915,025	0	225,915,025	45,183,005	180,732,020
AT DECEMBER 2029	3,407,816,781	882,308,818	2,525,507,963	505,101,593	2,902,715,188
INDIANA CONTRIBUTIONS 2030	0	0	0	0	0
PROJECTED EARNINGS	241,954,991	0	241,954,991	48,390,998	193,563,993
AT DECEMBER 2030	3,649,771,773	882,308,818	2,767,462,955	553,492,591	3,096,279,182
INDIANA CONTRIBUTIONS 2031	0	0	0	0	0
PROJECTED EARNINGS	259,133,796	0	259,133,796	51,826,759	207,307,037
AT DECEMBER 2031	3,908,905,568	882,308,818	3,026,596,750	605,319,350	3,303,586,218
INDIANA CONTRIBUTIONS 2032	0	0	0	0	0
PROJECTED EARNINGS	277,532,295	0	277,532,295	55,506,459	222,025,836
AT DECEMBER 2032	4,186,437,864	882,308,818	3,304,129,046	660,825,809	3,525,612,055
INDIANA CONTRIBUTIONS 2033	0	0	0	0	0
PROJECTED EARNINGS	297,237,088	0	297,237,088	59,447,418	237,789,671
AT DECEMBER 2033	4,483,674,952	882,308,818	3,601,366,134	720,273,227	3,763,401,725
INDIANA CONTRIBUTIONS 2034	0	0	0	0	0
PROJECTED EARNINGS	318,340,922	0	318,340,922	63,668,184	254,672,737
AT DECEMBER 2034	4,802,015,874	882,308,818	3,919,707,056	783,941,411	4,018,074,463
INDIANA CONTRIBUTIONS 2035	0	0	0	0	0
PROJECTED EARNINGS	340,943,127	0	340,943,127	68,188,625	272,754,502
AT DECEMBER 2035	5,142,959,001	882,308,818	4,260,650,183	852,130,037	4,290,828,964
INDIANA CONTRIBUTIONS 2036	0	0	0	0	0
PROJECTED EARNINGS	365,150,089	0	365,150,089	73,030,018	292,120,071
AT DECEMBER 2036	5,508,109,090	882,308,818	4,625,800,272	925,160,054	4,582,949,035
INDIANA CONTRIBUTIONS 2037	0	0	0	0	0
PROJECTED EARNINGS	391,075,745	0	391,075,745	78,215,149	312,860,596
AT DECEMBER 2037	5,899,184,835	882,308,818	5,016,876,017	1,003,375,203	4,895,809,632

NOTES:

ANNUAL INVESTMENT EARNINGS RATE: 7.10%

QUALIFIED TAX RATE: 20.00%

INDIANA MICHIGAN POWER COMPANY
DEVELOPMENT OF ESTIMATED NUCLEAR DECOMMISSIONING TRUST
AS OF DECEMBER 31, 2017 - 2037

DESCRIPTION	MARKET VALUE $	TAX BASIS VALUE $	UNREALIZED GAIN/LOSS $	TAXES DUE UNREALIZED GAINS $	LIQUIDATION VALUE $
AT DECEMBER 2016	$1,390,697,559	$874,308,818	$516,388,741	$103,277,748	$1,287,419,811
INDIANA CONTRIBUTIONS 2017	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	98,281,246	0	98,281,246	19,656,249	78,624,997
AT DECEMBER 2017	1,492,978,805	878,308,818	614,669,987	122,933,997	1,370,044,808
INDIANA CONTRIBUTIONS 2018	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	105,499,129	0	105,499,129	21,099,826	84,399,303
AT DECEMBER 2018	1,602,477,934	882,308,818	720,169,116	144,033,823	1,458,444,111
INDIANA CONTRIBUTIONS 2019	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	113,256,694	0	113,256,694	22,651,339	90,605,355
AT DECEMBER 2019	1,719,734,628	886,308,818	833,425,810	166,685,162	1,553,049,466
INDIANA CONTRIBUTIONS 2020	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	121,523,291	0	121,523,291	24,304,658	97,218,633
AT DECEMBER 2020	1,845,257,920	890,308,818	954,949,102	190,989,820	1,654,268,099
INDIANA CONTRIBUTIONS 2021	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	130,372,683	0	130,372,683	26,074,537	104,298,147
AT DECEMBER 2021	1,979,630,603	894,308,818	1,085,321,785	217,064,357	1,762,566,246
INDIANA CONTRIBUTIONS 2022	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	139,563,958	0	139,563,958	27,912,792	111,651,166
AT DECEMBER 2022	2,123,194,560	898,308,818	1,224,885,742	244,977,148	1,878,217,412
INDIANA CONTRIBUTIONS 2023	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	149,685,217	0	149,685,217	29,937,043	119,748,173
AT DECEMBER 2023	2,276,879,777	902,308,818	1,374,570,959	274,914,192	2,001,965,585
INDIANA CONTRIBUTIONS 2024	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	160,520,024	0	160,520,024	32,104,005	128,416,019
AT DECEMBER 2024	2,441,399,801	906,308,818	1,535,090,983	307,018,197	2,134,381,605
INDIANA CONTRIBUTIONS 2025	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	172,118,686	0	172,118,686	34,423,737	137,694,949
AT DECEMBER 2025	2,617,518,487	910,308,818	1,707,209,669	341,441,934	2,276,076,553
INDIANA CONTRIBUTIONS 2026	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	184,535,053	0	184,535,053	36,907,011	147,628,043
AT DECEMBER 2026	2,806,053,541	914,308,818	1,891,744,723	378,348,945	2,427,704,596
INDIANA CONTRIBUTIONS 2027	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	197,826,775	0	197,826,775	39,565,355	158,261,420
AT DECEMBER 2027	3,007,880,315	918,308,818	2,089,571,497	417,914,299	2,589,966,016

INDIANA MICHIGAN POWER COMPANY
DEVELOPMENT OF ESTIMATED NUCLEAR DECOMMISSIONING TRUST
BALANCE AS OF DECEMBER 31, 2017 - 2037

DESCRIPTION	MARKET VALUE $	TAX BASIS VALUE $	UNREALIZED GAIN/LOSS $	TAXES DUE UNREALIZED GAINS $	LIQUIDATION VALUE $
AT DECEMBER 2027	$3,007,880,315	$918,308,818	$2,089,571,497	$417,914,299	$2,589,966,016
INDIANA CONTRIBUTIONS 2028	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	212,055,562	0	212,055,562	42,411,112	169,644,450
AT DECEMBER 2028	3,223,935,877	922,308,818	2,301,627,059	460,325,412	2,763,610,466
INDIANA CONTRIBUTIONS 2029	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	227,287,479	0	227,287,479	45,457,496	181,829,983
AT DECEMBER 2029	3,455,223,357	926,308,818	2,528,914,539	505,782,908	2,949,440,449
INDIANA CONTRIBUTIONS 2030	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	243,593,247	0	243,593,247	48,718,649	194,874,597
AT DECEMBER 2030	3,702,816,603	930,308,818	2,772,507,785	554,501,557	3,148,315,046
INDIANA CONTRIBUTIONS 2031	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	261,330,571	0	261,330,571	52,266,114	209,064,456
AT DECEMBER 2031	3,968,147,174	934,308,818	3,033,838,356	606,767,671	3,361,379,503
INDIANA CONTRIBUTIONS 2032	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	280,036,376	0	280,036,376	56,007,275	224,029,101
AT DECEMBER 2032	4,252,183,550	938,308,818	3,313,874,732	662,774,946	3,589,408,603
INDIANA CONTRIBUTIONS 2033	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	300,060,940	0	300,060,940	60,012,188	240,048,752
AT DECEMBER 2033	4,556,244,490	942,308,818	3,613,935,672	722,787,134	3,833,457,356
INDIANA CONTRIBUTIONS 2034	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	321,497,237	0	321,497,237	64,299,447	257,197,789
AT DECEMBER 2034	4,881,741,727	946,308,818	3,935,432,909	787,086,582	4,094,655,145
INDIANA CONTRIBUTIONS 2035	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	344,444,792	0	344,444,792	68,888,958	275,555,833
AT DECEMBER 2035	5,230,186,518	950,308,818	4,279,877,700	855,975,540	4,374,210,978
INDIANA CONTRIBUTIONS 2036	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	369,010,150	0	369,010,150	73,802,030	295,208,120
AT DECEMBER 2036	5,603,196,668	954,308,818	4,648,887,850	929,777,570	4,673,419,098
INDIANA CONTRIBUTIONS 2037	4,000,000	4,000,000	0	0	4,000,000
PROJECTED EARNINGS	395,307,365	0	395,307,365	79,061,473	316,245,892
AT DECEMBER 2037	6,002,504,033	958,308,818	5,044,195,215	1,008,839,043	4,993,664,990
NOTES:					
ANNUAL INVESTMENT EARNINGS RATE:		7.05%			
QUALIFIED TAX RATE:		20.00%			

2015 DECOMMISSIONING FUNDING STATUS REPORT
Power Reactor Decommissioning Funding Assurance as of December 31, 2014

Plant Name	Expected Termination Date as of 3/31/2015	Actual DTF Balance (As of 12/31/14)	Projected DTF Balance Prior to Decommissioning	NRC Minimum[1] or Site-Specific Cost Estimate	Estimated Funds Remaining in DTF After Decommissioning[2]
Arkansas Nuclear One, Unit 1	5/20/2034	$429,500,000	$677,539,060	$480,265,214	$263,154,915
Arkansas Nuclear One, Unit 2	7/17/2038	$340,400,000	$643,007,331	$500,098,130	$202,125,459
Arnold (Duane) Energy Center	2/21/2034	$417,524,852	$670,652,739	$610,013,140	$129,689,058
Beaver Valley Power Station, Unit 1	1/29/2036	$270,773,373	$594,925,486	$673,694,000	$258,977,929
Beaver Valley Power Station, Unit 2	5/27/2047	$347,248,997	$663,703,656	$509,778,114	$215,533,043
Braidwood Station, Unit 1	10/17/2026	$306,300,000	$418,379,369	$780,166,000	($6,302,379)
Braidwood Station, Unit 2	12/18/2027	$330,908,000	$439,026,081	$849,702,000	($15,432,002)
Browns Ferry Nuclear Power Station, Unit 1	12/20/2033	$246,553,343	$633,618,270	$673,038,790	$83,276,490
Browns Ferry Nuclear Power Station, Unit 2	6/28/2034	$235,734,175	$623,706,040	$673,038,790	$76,890,663
Browns Ferry Nuclear Power Station, Unit 3	7/2/2036	$212,258,675	$623,114,521	$673,038,790	$76,379,459
Brunswick Steam Electric Plant, Unit 1	9/8/2036	$463,914,365	$1,031,020,943	$649,641,968	$361,351,714
Brunswick Steam Electric Plant, Unit 2	12/27/2034	$512,846,968	$826,003,090	$649,641,968	$244,797,426
Byron Station, Unit 1	10/31/2024	$336,095,000	$458,041,909	$780,504,000	$49,111,183
Byron Station, Unit 2	11/6/2026	$323,772,000	$369,165,457	$839,566,000	($82,837,805)
Callaway Plant	10/18/2024	$410,793,584	$779,070,455	$521,654,470	$86,518,287
Calvert Cliffs Nuclear Power Plant, Unit 1	7/31/2034	$341,609,000	$505,226,805	$485,981,251	$58,829,088
Calvert Cliffs Nuclear Power Plant, Unit 2	8/13/2036	$437,386,000	$674,376,610	$485,981,251	$253,375,003
Catawba Nuclear Station, Unit 1	12/5/2043	$375,335,162	$814,216,354	$516,687,235	$375,728,390
Catawba Nuclear Station, Unit 2	12/5/2043	$371,738,155	$822,653,790	$516,687,235	$385,440,645
Clinton Power Station	9/29/2026	$500,932,000	$895,785,845	$996,672,000	$464,734,107
Columbia Generating Station	12/20/2043	$218,100,000	$606,899,066	$459,996,100	$214,957,451
Comanche Peak Steam Electric Station, Unit 1	2/8/2030	$384,307,998	$652,289,826	$516,687,235	$196,333,256
Comanche Peak Steam Electric Station, Unit 2	2/2/2033	$442,977,196	$795,859,920	$516,687,235	$361,241,635
Cook (Donald C.) Nuclear Power Plant, Unit 1	10/25/2034	$537,925,429	$874,634,252	$517,059,936	$450,797,901
Cook (Donald C.) Nuclear Power Plant, Unit 2	12/23/2037	$489,331,963	$865,429,482	$521,654,470	$434,778,914
Cooper Nuclear Station	1/18/2034	$565,543,636	$910,846,618	$631,256,502	$362,584,545
Crystal River Nuclear Plant, Unit 3	3/13/2013	$876,976,011	$1,050,833,079	$873,398,263	$715,817,987
Davis-Besse Nuclear Power Station	4/22/2017	$513,842,141	$538,368,850	$493,801,102	$88,545,565
Diablo Canyon Nuclear Power Plant, Unit 1	11/2/2024	$1,138,700,000	$1,388,266,019	$523,105,465	$679,439,951
Diablo Canyon Nuclear Power Plant, Unit 2	8/26/2025	$1,486,800,000	$1,840,030,067	$523,105,465	$1,435,716,246
Dresden Nuclear Power Station, Unit 2	12/22/2029	$619,880,000	$835,149,632	$657,346,431	$254,124,043
Dresden Nuclear Power Station, Unit 3	1/12/2031	$633,769,000	$874,002,681	$657,346,431	$298,810,479
Farley (Joseph M.) Nuclear Plant, Unit 1	6/25/2037	$383,952,164	$687,491,278	$489,228,999	$283,734,541
Farley (Joseph M.) Nuclear Plant, Unit 2	3/31/2041	$369,629,218	$726,917,798	$489,228,999	$333,495,893

1 NRC Minimum (§50.75(c)): 1986$*((.65*Labor) + (.13*Energy) + (.22*Burial)) = 2014$.
2 Remaining funds in Trust considers growth through decommissioning, including expected earnings, fund contributions, and expenditures.

2015 DECOMMISSIONING FUNDING STATUS REPORT
Power Reactor Decommissioning Funding Assurance as of December 31, 2014

Plant Name	Expected Termination Date as of 3/31/2015	Actual DTF Balance (As of 12/31/14)	Projected DTF Balance Prior to Decommissioning	NRC Minimum[1] or Site-Specific Cost Estimate	Estimated Funds Remaining in DTF After Decommissioning[2]
Fermi (Enrico) Atomic Power Plant, Unit 2	3/20/2025	$1,156,000,000	$1,418,776,849	$1,069,534,735	$482,588,839
Fitzpatrick (James A.) Nuclear Power Plant	10/17/2034	$738,340,000	$1,097,445,956	$651,374,598	$562,224,737
Fort Calhoun Station	8/9/2033	$275,729,000	$450,934,428	$438,189,755	$48,936,494
Ginna (Robert E.) Nuclear Power Plant	9/18/2029	$403,940,000	$542,409,251	$459,571,157	$129,981,040
Grand Gulf Nuclear Station	11/1/2024	$735,000,000	$1,119,393,059	$673,038,790	$564,177,219
Harris (Shearon) Nuclear Power Plant	10/24/2046	$455,355,530	$981,566,234	$496,720,472	$595,425,036
Hatch (Edwin I.) Nuclear Plant, Unit 1	8/6/2034	$499,257,223	$808,286,902	$644,302,527	$237,523,970
Hatch (Edwin I.) Nuclear Plant, Unit 2	6/13/2038	$451,754,523	$794,445,225	$644,302,527	$221,604,106
Hope Creek Nuclear Power Station	4/11/2046	$519,995,720	$972,592,907	$673,038,790	$395,336,528
Indian Point, Unit 2	9/28/2013	$529,410,000	$529,410,000	$523,880,691	$64,378,789
Indian Point, Unit 3	12/12/2015	$676,650,000	$690,307,744	$523,880,691	$230,976,520
Kewaunee Nuclear Power Plant	12/31/2014	$392,285,515	$885,499,889	$452,189,000	$683,951,539
LaSalle County Station, Unit 1	4/17/2022	$453,349,000	$697,185,173	$910,428,000	$232,909,402
LaSalle County Station, Unit 2	12/16/2023	$453,726,000	$716,093,542	$954,631,000	$218,560,170
Limerick Generating Station, Unit 1	10/26/2024	$372,731,000	$594,684,382	$693,366,955	$24,940,401
Limerick Generating Station, Unit 2	6/22/2029	$384,612,000	$825,564,778	$693,366,955	$245,505,206
McGuire (William B.) Nuclear Station, Unit 1	3/3/2041	$464,115,283	$784,224,994	$516,687,235	$346,718,279
McGuire (William B.) Nuclear Station, Unit 2	3/3/2043	$508,168,021	$893,674,694	$516,687,235	$472,600,730
Millstone Nuclear Power Station, Unit 2	7/31/2035	$568,500,000	$857,760,828	$500,852,433	$448,317,647
Millstone Nuclear Power Station, Unit 3	11/25/2045	$594,000,000	$1,101,797,203	$532,498,030	$695,203,815
Monticello Nuclear Generating Plant	9/8/2030	$478,725,246	$731,925,922	$603,807,723	$193,831,241
Nine Mile Point Nuclear Station, Unit 1	8/22/2029	$619,909,000	$753,004,574	$619,664,616	$200,145,741
Nine Mile Point Nuclear Station, Unit 2	10/31/2046	$442,783,000	$836,491,625	$693,366,955	$217,257,635
North Anna Power Station, Unit 1	4/1/2038	$348,770,000	$555,956,964	$494,338,790	$108,402,453
North Anna Power Station, Unit 2	8/21/2040	$333,920,000	$558,023,342	$494,338,790	$110,779,076
Oconee Nuclear Station, Unit 1	2/6/2033	$383,057,594	$550,714,345	$480,265,214	$117,288,768
Oconee Nuclear Station, Unit 2	10/6/2033	$381,115,981	$555,270,450	$480,265,214	$122,528,925
Oconee Nuclear Station, Unit 3	7/19/2034	$501,119,063	$741,136,163	$480,265,214	$336,502,447
Oyster Creek Nuclear Power Plant	12/31/2019	$861,564,000	$1,773,442,650	$939,447,000	$1,569,611,328
Palisades Nuclear Plant	3/24/2031	$384,160,000	$531,545,393	$484,751,142	$90,423,000
Palo Verde Nuclear Generating Station, Unit 1	6/1/2045	$903,329,000	$1,567,700,754	$523,105,465	$379,559,125
Palo Verde Nuclear Generating Station, Unit 2	4/24/2046	$964,809,000	$1,741,540,462	$523,105,465	$505,503,258
Palo Verde Nuclear Generating Station, Unit 3	11/25/2047	$938,808,000	$1,666,740,403	$523,105,465	$414,737,635
Peach Bottom Atomic Power Station, Unit 2	8/8/2033	$539,766,350	$855,758,092	$693,366,955	$260,558,183

1 NRC Minimum (§50.75(c)): 1986$*((.65*Labor) + (.13*Energy) + (.22*Burial)) = 2014$.
2 Remaining funds in Trust considers growth through decommissioning, including expected earnings, fund contributions, and expenditures.

2015 DECOMMISSIONING FUNDING STATUS REPORT
Power Reactor Decommissioning Funding Assurance as of December 31, 2014

Plant Name	Expected Termination Date as of 3/31/2015	Actual DTF Balance (As of 12/31/14)	Projected DTF Balance Prior to Decommissioning	NRC Minimum[1] or Site-Specific Cost Estimate	Estimated Funds Remaining in DTF After Decommissioning[2]
Peach Bottom Atomic Power Station, Unit 3	7/2/2034	$560,403,283	$912,402,112	$693,366,955	$329,958,636
Perry Nuclear Power Plant	3/18/2026	$486,363,357	$867,950,261	$1,054,131,000	$337,103,742
Pilgrim Station	6/8/2032	$896,420,000	$1,271,709,974	$627,892,570	$787,887,376
Point Beach Nuclear Plant, Unit 1	10/5/2030	$379,545,734	$520,806,292	$451,305,639	$114,013,100
Point Beach Nuclear Plant, Unit 2	3/8/2033	$357,619,786	$514,999,816	$451,305,639	$5,374,770
Praire Island Nuclear Plant, Unit 1	8/9/2033	$318,133,086	$461,966,497	$444,747,697	$53,386,480
Praire Island Nuclear Plant, Unit 2	10/29/2034	$400,731,402	$595,634,879	$444,747,697	$207,123,799
Quad Cities Station, Unit 1	12/14/2032	$604,795,103	$882,374,749	$657,346,431	$308,439,527
Quad Cities Station, Unit 2	12/14/2032	$652,297,118	$950,327,131	$657,346,431	$386,594,263
River Bend Station (Regulated)	8/29/2025	$305,000,000	$507,230,825	$460,026,001	$159,564,817
River Bend Station (Non-Regulated)	8/29/2025	$332,800,000	$411,865,756	$197,154,001	$261,831,603
Robinson (H.B.) Plant, Unit 2	7/31/2030	$524,950,593	$835,210,328	$470,348,756	$458,247,995
Salem Nuclear Generating Station, Unit 1	8/13/2036	$555,284,611	$939,269,403	$516,687,235	$551,770,231
Salem Nuclear Generating Station, Unit 2	4/18/2040	$501,115,467	$920,056,759	$516,687,235	$527,359,461
San Onofre Nuclear Generating Station, Unit 2	12/31/2014	$886,200,000	$886,200,000	$939,400,000	$141,767,850
San Onofre Nuclear Generating Station, Unit 3	12/31/2014	$929,300,001	$929,300,000	$983,500,000	$145,066,577
Seabrook Nuclear Power Station	3/15/2030	$425,217,194	$576,713,840	$532,498,030	$91,067,270
Sequoyah Nuclear Plant, Unit 1	9/17/2020	$339,973,980	$452,945,489	$516,687,235	$22,353,663
Sequoyah Nuclear Plant, Unit 2	9/15/2021	$323,489,887	$453,033,772	$516,687,235	$22,478,851
South Texas Project, Unit 1	8/20/2027	$406,246,002	$567,018,735	$516,687,235	$104,708,241
South Texas Project, Unit 2	12/15/2028	$496,419,828	$702,536,409	$516,687,235	$350,513,572
St. Lucie Plant, Unit 1	3/1/2036	$665,809,174	$1,018,055,109	$499,838,310	$633,762,030
St. Lucie Plant, Unit 2	4/6/2043	$770,972,731	$1,358,108,190	$499,838,310	$1,024,870,598
Summer (Virgil C.) Nuclear Station	8/6/2042	$271,520,616	$631,865,646	$494,641,913	$196,057,852
Surry Power Station, Unit 1	5/25/2032	$373,200,000	$536,733,051	$479,312,541	$102,232,101
Surry Power Station, Unit 2	1/29/2033	$373,800,000	$545,197,584	$479,312,541	$112,169,072
Susquehanna Steam Electric Station, Unit 1	7/17/2042	$506,374,057	$878,734,754	$693,366,955	$265,549,732
Susquehanna Steam Electric Station, Unit 2	3/23/2044	$557,493,204	$1,000,208,097	$693,366,955	$405,261,052
Three Mile Island Nuclear Station, Unit 1	4/19/2034	$604,856,000	$890,101,245	$494,961,483	$491,844,193
Turkey Point Station, Unit 3	7/19/2032	$543,733,507	$772,655,425	$483,556,265	$369,015,349
Turkey Point Station, Unit 4	4/10/2033	$589,163,399	$849,854,377	$483,556,265	$457,804,933
Vermont Yankee Power Station	1/1/2015	$664,560,000	$1,116,659,670	$817,220,000	$800,956,857
Vogtle (Alvin W.) Nuclear Plant, Unit 1	1/16/2047	$312,058,357	$707,777,162	$516,687,235	$280,360,742
Vogtle (Alvin W.) Nuclear Plant, Unit 2	2/9/2049	$308,039,527	$704,995,572	$516,687,235	$276,407,360

1 NRC Minimum (§50.75(c)): 1986$*((.65*Labor) + (.13*Energy) + (.22*Burial)) = 2014$.
2 Remaining funds in Trust considers growth through decommissioning, including expected earnings, fund contributions, and expenditures.

2015 DECOMMISSIONING FUNDING STATUS REPORT
Power Reactor Decommissioning Funding Assurance as of December 31, 2014

Plant Name	Expected Termination Date as of 3/31/2015	Actual DTF Balance (As of 12/31/14)	Projected DTF Balance Prior to Decommissioning	NRC Minimum[1] or Site-Specific Cost Estimate	Estimated Funds Remaining in DTF After Decommissioning[2]
Waterford Generating Station, Unit 3	12/18/2024	$383,600,000	$547,771,177	$516,687,235	$133,392,609
Watts Bar Nuclear Plant, Unit 1	11/9/2035	$158,127,261	$449,016,980	$516,687,235	$16,782,896
Wolf Creek Generating Station	3/11/2045	$403,360,000	$1,010,371,877	$521,654,470	$602,785,392

1 NRC Minimum (§50.75(c)): 1986$*((.65*Labor) + (.13*Energy) + (.22*Burial)) = 2014$.
2 Remaining funds in Trust considers growth through decommissioning, including expected earnings, fund contributions, and expenditures.

AEP
INDIANA MICHIGAN POWER®
A unit of American Electric Power

Indiana Michigan Power
Cook Nuclear Plant
One Cook Place
Bridgman, MI 49106
IndianaMichiganPower.com

March 21, 2017

AEP-NRC-2017-12
10 CFR 50.75(f)(1)

Docket Nos.: 50-315
50-316

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-001

Donald C. Cook Nuclear Plant Units 1 and 2
DECOMMISSIONING FUNDING STATUS REPORT

In accordance with the requirements of 10 CFR 50.75(f)(1), Indiana Michigan Power Company, the licensee for Donald C. Cook Nuclear Plant (CNP), Units 1 and 2, hereby submits the biennial report on the status of decommissioning funding. The recovery of decommissioning funds for the eventual decommissioning of CNP Units 1 and 2 is fully assured through cost of service regulation and the resulting contribution of funds into an external trust.

When projected to the current license expiration date for each unit, the Nuclear Decommissioning Trust balance is greater than the U. S. Nuclear Regulatory Commission calculated minimum cost of decommissioning pursuant to 10 CFR 50.75(b) and (c), confirming compliance with the financial assurance requirements of 10 CFR 50.75.

This letter contains no new commitments. If you have any questions regarding the report or decommissioning funding, please contact Mr. Michael K. Scarpello, Regulatory Affairs Manager, at (269) 466-2649.

Sincerely,

Quinton S. Lies

Q. Shane Lies
Site Vice President

DMB/mll

Enclosure

c: R. J. Ancona, MPSC
A. W. Dietrich, NRC, Washington, D.C.
MDEQ – RMD/RPS
NRC Resident Inspector
C. D. Pederson, NRC, Region III
A. J. Williamson, AEP Ft. Wayne, w/o enclosure

A001
NRR

ENCLOSURE TO AEP-NRC-2017-12

**Indiana Michigan Power Company, Donald C. Cook Nuclear Plant Units 1 and 2
2016 U. S. Nuclear Regulatory Commission Financial Assurance Requirements Report for Decommissioning Nuclear Power Reactors**

As provided in 10 CFR 50.75(f)(1), each power reactor licensee is required to report to the U. S. Nuclear Regulatory Commission (NRC) on a calendar year basis, beginning on March 31, 1999, and every two years thereafter, on the status of its decommissioning funding for each reactor or share of reactors it owns.

1. The minimum decommissioning cost estimate, pursuant to 10 CFR 50.75(b) and (c):
   a. Cook Unit 1 $487,715,537
   b. Cook Unit 2 $492,049,320
   c. Total $979,764,857

   These cost estimates were determined using the burial cost escalation values and the methods outlined in NUREG-1307, Revision 16, to determine minimum values.

2. The amount accumulated in the fund allocated to radiological decommissioning reflects the market value of the funds accumulated through December 31, 2016, net of all taxes currently due for items included in 10 CFR 50.75(b) and (c) are:
   a. Cook Unit 1 $459,454,502
   b. Cook Unit 2 $418,248,246
   c. Total $877,702,748

3. A schedule of the annual amounts to be collected for items in 10 CFR 50.75(b) and (c) are as follows:
   a. See Table 1 below for schedule of contributions. While there are no changes for Indiana and Michigan, the FERC contributions are expected to decline in years 2019, 2020, 2021, 2026, 2027, and 2034 as wholesale customer's contracts expire.

   The citations for the Orders that provide these rates are the State of Michigan Case Number U-15276 and the State of Indiana Cause Number 44075

4. The assumptions used regarding rates of escalation in decommissioning costs, rates of earnings on decommissioning funds, and rates of other factors used in funding projections are as follows:

   A two percent real rate of return was applied to the annual balance for future funding projections. Incorporating the two percent real rate of return on trust assets as well as future contributions to the trust results in projected trust fund balances of approximately $653 million for Unit 1 and $633 million for Unit 2 net of tax at the time those units are shut-down, which are above the NRC minimum decommissioning cost estimates.

5. Any contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v):
   None

6. Any modifications occurring to a licensee's current method of providing financial assurances since the last submitted report:
   None

7. Any material changes to trust agreements:
   None

Table 1

Unit 1

	Contributions			
	Indiana	Michigan	FERC	Total
2017	$973,000	$729,750	$581,044	$2,283,794
2018	$973,000	$729,750	$581,044	$2,283,794
2019	$973,000	$729,750	$569,754	$2,272,504
2020	$973,000	$729,750	$379,918	$2,082,668
2021	$973,000	$729,750	$250,082	$1,952,832
2022	$973,000	$729,750	$250,082	$1,952,832
2023	$973,000	$729,750	$250,082	$1,952,832
2024	$973,000	$729,750	$250,082	$1,952,832
2025	$973,000	$729,750	$250,082	$1,952,832
2026	$973,000	$729,750	$241,873	$1,944,623
2027	$973,000	$729,750	$236,010	$1,938,760
2028	$973,000	$729,750	$236,010	$1,938,760
2029	$973,000	$729,750	$236,010	$1,938,760
2030	$973,000	$729,750	$236,010	$1,938,760
2031	$973,000	$729,750	$236,010	$1,938,760
2032	$973,000	$729,750	$236,010	$1,938,760
2033	$973,000	$729,750	$236,010	$1,938,760
10/25/2034	$810,833	$608,125	$87,479	$1,506,437

Unit 2

	Contributions			
	Indiana	Michigan	FERC	Total
2017	$973,000	$729,750	$581,044	$2,283,794
2018	$973,000	$729,750	$581,044	$2,283,794
2019	$973,000	$729,750	$569,754	$2,272,504
2020	$973,000	$729,750	$379,918	$2,082,668
2021	$973,000	$729,750	$250,082	$1,952,832
2022	$973,000	$729,750	$250,082	$1,952,832
2023	$973,000	$729,750	$250,082	$1,952,832
2024	$973,000	$729,750	$250,082	$1,952,832
2025	$973,000	$729,750	$250,082	$1,952,832
2026	$973,000	$729,750	$241,873	$1,944,623
2027	$973,000	$729,750	$236,010	$1,938,760
2028	$973,000	$729,750	$236,010	$1,938,760
2029	$973,000	$729,750	$236,010	$1,938,760
2030	$973,000	$729,750	$236,010	$1,938,760
2031	$973,000	$729,750	$236,010	$1,938,760
2032	$973,000	$729,750	$236,010	$1,938,760
2033	$973,000	$729,750	$236,010	$1,938,760
2034	$973,000	$729,750	$104,974	$1,807,724
2035	$973,000	$729,750	$39,814	$1,742,564
2036	$973,000	$729,750	$39,814	$1,742,564
12/23/2037	$973,000	$729,750	$39,814	$1,742,564

POLICY ISSUE
(INFORMATION)

September 28, 2015 SECY-15-0122

FOR: The Commissioners

FROM: William M. Dean, Director
Office of Nuclear Reactor Regulation

SUBJECT: SUMMARY FINDINGS RESULTING FROM THE STAFF REVIEW OF THE 2015 DECOMMISSIONING FUNDING STATUS REPORTS FOR OPERATING POWER REACTOR LICENSEES

PURPOSE:

This paper informs the Commission of the U.S. Nuclear Regulatory Commission (NRC) staff's findings from its review of the 2015 decommissioning funding status (DFS) reports for operating power reactor licensees. The regulations of Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.75(f)(1) require that licensees submit DFS reports to the NRC. The 2015 DFS reports were due to the NRC by March 31, 2015, reflecting decommissioning funding assurance information as of December 31, 2014. This paper does not address any new commitments or resource implications.

BACKGROUND:

In 1988, the NRC established requirements to assure that decommissioning of all licensed facilities will be accomplished in a safe and timely manner and that adequate licensee funds will be available for this purpose. In accordance with NRC regulations in 10 CFR 50.2, "Definitions," decommission means to remove a facility or site safely from service and reduce residual radioactivity to a level that permits: (1) release of the property for unrestricted use and termination of the license, or (2) release of the property under restricted conditions and termination of the license. For power reactor licensees, the costs of spent fuel management, site restoration, and other costs not related to license termination are currently not included within the scope of financial assurance for decommissioning.

CONTACT: Kosmas Lois, NRR/DIRS
301-415-8341

The Commission's regulations at 10 CFR 50.33(k)(1) and 10 CFR 50.75, "Reporting and Recordkeeping for Decommissioning Planning," require power reactor licensees to certify that they provide financial assurance for decommissioning. The amount to be provided must be equal to, or greater than, the amount stated in the table of minimum amounts (10 CFR 50.75(c)), also referred to as the NRC minimum, and adjusted annually to account for cost escalation.

In 1998, the NRC amended the decommissioning financial assurance rules to respond to the anticipated deregulation of the power generating industry, resulting in additional methods and flexibility for reactor licensees to provide financial assurance for decommissioning. Additionally, rule changes established the requirement that licensees submit a DFS report to the NRC on a biennial basis, which allow the agency to obtain the information necessary to monitor the status of decommissioning funds.

The Office of Nuclear Reactor Regulation's Office Instruction LIC-205, Revision 5, "Procedures for NRC's Independent Analysis of Decommissioning Funding Assurance for Operating Power Reactors," dated January 2015 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML14281A764), describes the methodology used by staff to determine whether a licensee has provided adequate decommissioning funding assurance.

DISCUSSION:

The regulations at 10 CFR 50.75(f)(1) state, "each power reactor licensee shall report, on a calendar-year basis, to the NRC by March 31, 1999, and at least once every 2 years thereafter on the status of its decommissioning funding for each reactor or part of a reactor that it owns." In 2015, all licensees submitted their DFS reports on or before March 31, 2015. The DFS reports included the following integral pieces of information: (1) the amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and 10 CFR 50.75(c); (2) the amount of decommissioning funds accumulated by the end of the calendar-year preceding the date of the report; (3) a schedule of the annual amounts remaining to be collected; (4) the assumptions used regarding rates of escalation in decommissioning costs, rates of earnings on decommissioning funds, and rates of other factors used in funding projections; (5) any contracts upon which the licensee is relying; (6) any modifications occurring to a licensee's current method of providing financial assurance since the last submitted report; and (7) any material changes to trust agreements. In accordance with the guidance in Office Instruction LIC-205, the NRC staff reviewed the information in the 2015 DFS reports for completeness and compliance with 10 CFR 50.75(f)(1). A table summarizing NRC staff's findings on the licensees' DFS reports is enclosed and is also available under ADAMS Accession No. ML15237A377.

The regulation at 10 CFR 50.75(c) requires licensees to demonstrate reasonable assurance of funding for decommissioning. Shortfalls should, therefore, be corrected in a timely manner. The staff notes that while the decommissioning funding amounts certified by licensees under this part do not represent the actual cost of plant decommissioning, they provide assurance that licensees have the bulk of the funds available to safely decommission the facility. Adjustments to the certification amount are required annually over the operating life of the facility and account for inflation that has occurred in the labor, energy, and waste burial component of decommissioning costs. Within five years prior to the projected end of operations, the regulation at 10 CFR 50.75(f) requires that each licensee submit a preliminary decommissioning cost estimate that includes an updated assessment of the major factors that could affect the cost to decommission. The preliminary cost estimate is a more accurate representation of the licensee's cost to decommission as compared to the NRC required minimum. Therefore, shortfalls identified during the operating cycle and between biennial decommissioning reporting periods are considered to be temporary lapses in funding for decommissioning that may be remedied by utilization of a parent company guarantee, trust fund growth, or trust fund contributions. In any event, guidance in Regulatory Guide (RG) 1.159, "Assuring Availability of Funds for Decommissioning Nuclear Reactors," states, "shortfalls identified in a biennial report must be corrected by the time the next biennial report is due." Pursuant to 10 CFR 50.75(e)(2), the NRC may take action on a case-by-case basis to ensure a licensee's adequate accumulation of decommissioning funds.

Results of NRC Staff's Review

The results from staff's review of the 2015 DFS reports are as follows:

- All operating power reactor licensees[1] met the reporting requirements of 10 CFR 50.75(f)(1);

- As of December 31, 2014, 101 of the 104 operating power reactors have demonstrated decommissioning funding assurance.

- Exelon Generating Company (Exelon) self-reported shortfalls for Braidwood Station, Units 1 and 2, and Byron Station, Unit 2, which the NRC staff calculated to range from $6 million to $84 million. Exelon is currently evaluating alternative funding mechanisms allowed by 10 CFR 50.75(e) and regulatory guidance contained in RG 1.159.

Consistent with the discussion above, Exelon is expected to correct any decommissioning funding shortfalls in a timely manner and report compliance to the NRC on or before March 31, 2017. RG 1.159 provides possible mechanisms Exelon can use to make up the shortage of funds, including reliance on normal decommissioning trust fund growth, cash deposits into trust funds, and/or parent company guarantees.

Of note is that since the last reporting cycle in 2013, many licensees have improved the quality of the information provided in their DFS report submittals. Consequently, the NRC staff did not have to issue any requests for additional information in order to evaluate the 2015 DFS reports.

Resolution of Issues from Last Reporting Requirement Cycle

There were no unresolved issues from the staff's review of the 2013 DFS report submittals.

CONCLUSION:

Based on its review of the 2015 DFS reports, the staff finds that all the licensees are in compliance with the decommissioning funding assurance reporting requirements of

[1] For this reporting cycle, NRC received 104 DFS reports from its operating power reactor licensees, including the five plants that were transitioning, or have transitioned, to a decommissioning status. These plants are: Kewaunee, SONGS Units 2 and 3, Crystal River, and Vermont Yankee. At the time of the next biennial DFS review, these plants will not be included as part of the operating power reactor reviews.

10 CFR 50.75(f)(1). With the exception of Exelon as described above, the staff also finds that the remaining licensees are in compliance with the decommissioning funding assurance requirements of 10 CFR 50.75. No later than March 31, 2017, Exelon must demonstrate decommissioning funding assurance for Braidwood Station, Units 1 and 2, and Byron Station, Unit 2.

Consistent with the objectives of Project Aim 2020, the staff is evaluating the efficacy of providing the Commission with results of the biennial decommissioning funding assurance reviews as a part of the Office of Nuclear Reactor Regulation's re-baselining effort. Notwithstanding this re-baselining activity, following the next licensee reporting cycle in 2017, any unresolved trust fund shortfalls or significant decline in a trust fund balance that may have an adverse impact on decommissioning activities will be communicated to the Commission.

COORDINATION:

The Office of the General Counsel has reviewed this paper and has no legal objection.

/RA/

William M. Dean, Director
Office of Nuclear Reactor Regulation

Enclosure:
2015 DFS Reports – Summary Table

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Consistent with the objectives of Project Aim 2020, the staff is evaluating the efficacy of providing the Commission with results of the biennial decommissioning funding assurance reviews as a part of the Office of Nuclear Reactor Regulation's re-baselining effort. Notwithstanding this re-baselining activity, following the next licensee reporting cycle in 2017, any unresolved trust fund shortfalls or significant decline in a trust fund balance that may have an adverse impact on decommissioning activities will be communicated to the Commission.

COORDINATION:

The Office of the General Counsel has reviewed this paper and has no legal objection.

William M. Dean, Director
Office of Nuclear Reactor Regulation

Enclosure:
2015 DFS Reports – Summary Table

200800001

ADAMS Accession No.: ML15237A369; Pkg: ML15237A367; * - e-mail concurrence

OFFICE	NRR/DIRS/IFIB	NRR/DIRS/IFIB	NRR/DIRS	TechEd*	OGC/GCHEA*	NRR
NAME	KLois	ABowers	SMorris (AHowe For)	CHsu	EWilliamson (BMizuno For)	WDean
DATE	08/25/2015	09/08/2015	09/09/2015	09/15/2015	09/16/2015	09/282015

OFFICIAL RECORD COPY

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Edward T. Rutter
Chief Technical Advisor
Indiana Office of Utility Consumer Counselor

November 7, 2017

Date