STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION IN RATE BASE OF QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECT; (4) ENHANCEMENTS TO THE DRY SORBENT INJECTION SYSTEM; (5) ADVANCED METERING INFRASTRUCTURE; (6) RATE ADJUSTMENT MECHANISM PROPOSALS; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	**CAUSE NO. 45235**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 1

TESTIMONY OF OUCC WITNESS

MICHAEL D. ECKERT

August 20, 2019

Respectfully submitted,

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TESTIMONY OF OUCC WITNESS MICHAEL D. ECKERT
CAUSE NO. 45235
INDIANA MICHIGAN POWER COMPANY

I. INTRODUCTION

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

A: My name is Michael D. Eckert. I am employed by the Indiana Office of Utility Consumer Counselor ("OUCC") as the Assistant Director of the Electric Division. My business address is 115 W. Washington St., Suite 1500 South Tower, Indianapolis, Indiana 46204. For a summary of my educational and professional experience and my preparations for this case, please see Appendix A attached to my testimony.

Q: What is the purpose of your testimony?

A: I introduce and provide an overview of the OUCC's witnesses and their testimony. I describe the OUCC's revenue requirement analysis and Indiana Michigan Power Company's ("I&M" or "Petitioner") requested relief. More specifically, I address the OUCC's position on I&M's purchased power over the benchmark, Life Cycle Management ("LCM") Rider, and Fuel Clause Adjustment ("FAC") Rider. I explain and support adjustments to I&M's proposed Nuclear Decommissioning Trust Fund ("DTF") expense, nuclear decommissioning study expenses and rate case expenses, and the D.C. Cook Nuclear Clean Water Act Rule 316(b) ("Rule 316(b)") study expenses. I further explain why I&M's request to continue the current amount of annual ratepayer contributions to the Nuclear DTF is unnecessary and unreasonable and provide documents from the Nuclear

Regulatory Commission ("NRC") that indicate ongoing contributions to I&M's Nuclear DTF are not required.

Q: To the extent you do not address a specific item or adjustment, should that be construed to mean you agree with I&M's proposal for that item?

A: No. Exclusion from my testimony of any specific adjustments or amounts proposed by I&M does not indicate my approval of those adjustments or amounts, but rather that the scope of my testimony is limited to the specific items addressed herein.

II. OUCC WITNESSES

Q: Who are the OUCC's witnesses in this Cause?

A: The following OUCC witnesses provide testimony in this Cause:

Mr. Mark Garrett testifies regarding revenue requirements and sponsors the OUCC's overall revenue requirements recommendation for I&M. He recommends adjustments to rate base, and to I&M's operating revenues and expenses. Specifically, Mr. Garrett makes adjustments to 1) annual and long-term incentive compensation expense; 2) non-qualified supplemental employee retirement plan expense; 3) employee benefits expense; 4) vegetation management expense; and 5) rate case expense amortization. In developing the OUCC's recommended revenue requirements, Mr. Garrett reflects the impact of recommendations of other OUCC witnesses in his revenue requirements calculations. (Public's Exhibit No. 2)

Mr. Wes Blakley provides analysis and recommends the Commission 1) deny I&M's request to continue to track consumables expense through its Environmental Cost Rider ("ECR"); 2) approve an alternative treatment for the excess accumulated deferred federal income tax ("EADFIT") credit; 3) address the South Bend Solar Project; 4) only accept I&M's new Automated Meter Infrastructure ("AMI") Rider if the Commission approves I&M's request for AMI; and 5) if the AMI Rider is accepted, the Commission should also recognize the retirement of the Automated Meter Reading ("AMR") meters as a decrease to depreciation expense within the AMI Rider. (Public's Exhibit No. 3)

Ms. Margaret Stull discusses the OUCC's review and analysis of I&M's proposed "prepaid pension asset." She recommends the Commission reject I&M's proposal to include its net "prepaid pension asset" in its rate base as of December

31, 2020, and proposes that I&M's pension expense be increased in order to recognize the gap between ERISA required contributions and FASB pension expense. (Public's Exhibit No. 4)

Mr. Kaleb Lantrip testifies regarding I&M's proposals to modify its Resource Adequacy Rider, PJM/Off-System Sales Rider ("OSS"), and EZ Bill Cost Recovery program. (Public's Exhibit No. 5)

Mr. John Haselden testifies regarding 1) I&M's proposed treatment of the DSM/EE Rider and 2) ongoing and new customer assistance and economic development programs. (Public's Exhibit No. 6)

Mr. Mike Gahimer testifies on I&M's proposal to recover NITS Charges through its OSS/PJM Rider tracker mechanism. He also presents concerns regarding a lack of oversight of NITS projects — including the extent to which NITS projects are analyzed by I&M's regional transmission operator, PJM. His testimony focuses on the differences between projects identified by PJM as "baseline" as compared to "supplemental" projects. He also testifies on I&M's proposal to recover Capacity Performance Insurance premiums from customers in rates. (Public's Exhibit No. 7)

Mr. Anthony Alvarez addresses I&M's proposed Distribution Management Plan. He also addresses I&M's proposed: 1) AMI deployment; 2) modification to the methodology used to set the funding level for its Major Storm Reserve; and 3) Rockport Generating Plant Unit 2 high pressure turbine replacement project. (Public's Exhibit No. 8)

Ms. Cynthia Armstrong testifies regarding the OUCC's recommendation that the Commission deny I&M's rate base inclusion of enhancements to the Dry Sorbent Injection ("DSI") systems and related operation and maintenance ("O&M") expenses on Rockport Units 1 and 2. (Public's Exhibit No. 9)

Ms. Lauren Aguilar testifies and presents the OUCC's analysis regarding: 1) AMI opt out; 2) Plugged-in Electric Vehicle ("PEV") Pilot; 3) environmental consumables and emission allowance cost recovery; and 5) coal combustion residuals ("CCR") pond closure costs. She also discusses the OUCC's concerns with the IM Green program proposal and provides recommendations for improving the program and its attractiveness to I&M customers. (Public's Exhibit No. 10)

Mr. David Garrett testifies regarding depreciation expense and return on equity. Mr. Garrett explains the key factors driving his depreciation expense adjustment are: 1) removing interim retirements from the calculation of production plant depreciation rates; 2) removing the contingency costs from I&M's proposed terminal net salvage rates; 3) removing the escalation factors from I&M's

proposed terminal net salvage rates; 4) adjusting I&M's proposed service lives for several of its transmission and distribution accounts; and 5) using the current depreciation rate for Account 370 – Meters. Mr. Garrett analyzes I&M's requested cost of equity of 10.50%[1] and recommends the Commission adopt the OUCC's proposed cost of equity of 9.10%. (Public's Exhibit No. 11, Parts I and II)

Mr. Glenn Watkins testifies about the reasonableness of I&M's retail class cost of service study and the allocation of revenue requirements to the various rate classes. Mr. Watkins addresses I&M's residential billing determinants and offers an analysis of I&M's cost to serve SDI, its largest special contract customer. He also addresses I&M's proposed rate design, including the proposed increase to the residential fixed monthly customer charge, I&M's proposed declining block residential rate structure, and the proposed optional residential demand charge. (Public's Exhibit No. 12)

Q: Does the OUCC have overarching concerns about this particular I&M rate request?

A. Yes. Individual OUCC witnesses put forth testimony and recommendations regarding specific issues or requests contained in I&M's case. Many of these requests are optional or have discretionary components. The OUCC and the hundreds of ratepayers who submitted comments are gravely concerned about the immediate financial impacts of these requests. It is understandable that I&M has included all these requests, because large capital expenditures provide significant returns I&M expects to realize. However, the Indiana General Assembly has declared a policy that specifically recognizes affordability of utility services for present and future generations of Indiana citizens.[2]

The Commission is charged with the task of balancing the interests of the utilities with ratepayers. The OUCC also wants financially sound utilities that can provide quality services at reasonable prices. But the fact is, I&M received new

[1] Cause No. 45235, Direct Testimony of Robert B. Hervert, p. 2, l. 20.
[2] I.C. § 8-1-2-.05.

rates and charges in May 2018 with an annual revenue increase of $96,823,006,[3] and is here now requesting an annual revenue increase of $172,004,651.[4] At some point, it becomes crucial to review whether the scales become imbalanced and weigh too heavily in the utilities' favor. Through the individual witnesses' testimonies, the OUCC requests the Commission examine the various components of I&M's requests and determine if they are really necessary and prudent at this point in time, or if some of these expenditures should be implemented more gradually. I&M has not presented sufficient evidence that the Commission should "green light" its entire package now.

I&M's case is filled with requests that reduce its risks, but it has not substantiated its claimed needs. The Commission has the opportunity and ability to look at the whole picture, to say no and make clear the standards I&M should meet. In order for the Commission to maintain the flexibility and optionality it articulated in the Vectren Order,[5] the OUCC respectfully suggests the Commission hit a "pause" button on several of the requests presented. For example, as outlined in OUCC witness Alvarez's testimony, I&M included in its rate request T&D projects with much less project information than what is required under the TDSIC statute. The Commission should not reward I&M by allowing it to circumvent the standards set forth in the TDSIC statute and case law. Another example is the proposed AMI program, also set forth in Witness

[3] *In re Ind. & Mich. Pwr.*, Cause No. 44967, Final Order, p. 29 (Ind. Util. Regulatory Comm'n May 30, 2018).
[4] Cause No. 45235, Petitioner's Exhibit A-1, p. 1 of 1, l. 12.
[5] *In re S. Ind. Gas & Elec. Co.*, Cause No. 45052, Final Order, p. 26 (Ind. Util. Regulatory Comm'n April 24, 2019).

Alvarez's testimony. I&M presented insufficient cost benefit analysis and fails to meet its burden of proof. A further issue is the process set forth by I&M for inclusion of NITS projects. OUCC witness Mike Gahimer sets forth clear evidence of how the supplemental projects are determined and "approved." The OUCC is not proposing the Commission usurp FERC jurisdiction, but rather open an investigation to examine the process and determine how these NITS project costs should be passed on to Indiana ratepayers.

The OUCC urges the Commission to maintain flexibility and its ability to require sufficient evidence, especially in light of Indiana's new focus on its emerging energy policy. The Commission should only approve requests that are necessary and reasonable for I&M to provide quality electric service at reasonable prices.

III. <u>OUCC REVENUE REQUIREMENT ANALYSIS</u>

Q: Please provide an overview of the OUCC's process to evaluate I&M's revenue requirements.

A: As an investor-owned utility, I&M's rates and charges are regulated under Ind. Code § 8-1-2-1, *et seq*. The OUCC compared the operating revenues, operating expenses, rate base figures, capital structure, and net operating income from I&M's historical calendar year (2018) against the same from its forecasted test year (2020). Adjustments to the forecasted test year revenue and expense data were generally made to reflect changes that will and are projected to occur by the end of the forecasted 2020 test year. The OUCC also made adjustments to Petitioner's forecasted rate base and proposed rate of return ("ROR") on rate base.

In developing its positions, the OUCC reviewed I&M's case-in-chief, exhibits, accounting schedules, attachments, and workpapers. OUCC staff and witnesses issued data requests and gathered financial information about I&M through discovery. OUCC staff members attended meetings with I&M staff in Fort Wayne, Indiana and Columbus, Ohio, and also participated in several conference calls with I&M staff to discuss technical issues. The OUCC attended the public field hearings in this Cause and reviewed written comments from I&M's ratepayers. Customer comments are included with the OUCC's case as Public's Exhibit No. 13.

IV. <u>I&M'S REQUESTED REVENUE REQUIREMENT</u>

Q: What rate relief does I&M seek in this Cause?

A: I&M seeks an overall increase in revenue of $172,004,651,[6] based on an adjusted Original Cost Rate Base of $4,946,962,201.[7] As provided in its filing, I&M is seeking a base rate revenue requirement of $1,669,746,786.[8]

Q: What base rate revenue requirement was approved in I&M's last electric rate case?

A: The Commission's Order in Cause No. 44967, dated May 30, 2018, authorized a base rate revenue requirement of $1.430 billion.[9]

Q: Have you performed a calculation to show how I&M's current trackers impact an Indiana residential customer's monthly bill based on 1,000 kWh per month usage?

A: Yes. Table 1 below illustrates the impact of trackers on the monthly bill of an

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[6] Cause No. 45235, Petitioner's Exhibit A-1, p. 1 of 1, l. 12.
[7] Cause No. 45235, Petitioner's Exhibit A-1, p. 1 of 1, l. 1.
[8] Cause No. 45235, Petitioner's Exhibit A-5, p. 5 of 30, l. 7, column 33, ($1,497,742,135) and Petitioner's Exhibit A-1, p. 1, l. 12 ($172,004,651)
[9] *In re Ind. & Mich. Pwr.*, Cause No. 44967, Final Order, p. 31 (Ind. Util. Regulatory Comm'n May 30, 2018).

I&M Indiana residential customer using 1,000 kWh per month. The current base rate portion of the monthly bill totals $115.08. The total monthly bill, including trackers, equals $132.53. Therefore, 13.16% of a typical I&M Indiana residential customer's monthly bill is associated with I&M's numerous trackers, and, if approved, the rate increase proposed by I&M in this Cause would increase the dollar amount recovered through its trackers since its last base rate case.

Table 1: Residential Customer Bill Calculation as of August 5, 2019

Description:	kWh		Rate	$	% of Bill
Customer Charge				$10.50	7.92%
Energy Charge	1,000	*	$0.104580	104.58	78.91%
DSM/EE charge	1,000	*	$0.001378	1.38	1.04%
OSS/PJM Charge	1,000	*	$0.020142	20.14	15.20%
ECR Charge	1,000	*	($0.000227)	(0.23)	(0.17%)
LCM Charge	1,000	*	$0.000676	0.68	0.51%
RAR Charge	1,000		($0.000823)	(0.82)	(0.62%)
Phase In Rider Charge	1,000		($0.000118)	(0.12)	(0.09%)
Sub-Total				136.11	102.70%
FAC Charge	1,000	*	($0.003583)	(3.58)	(2.70%)
Total Billing Amount				$132.53	100.00%
Base and Energy Charge				115.08	86.84%
Trackers (Excluding FAC)				21.03	15.87%
FAC				(3.58)	(2.70%)
Total				$132.53	100.00%

*I&M's Tariffs as of August 5, 2019 https://www.IM.com/about-us/rates-tariffs/electric-service-tariff)

Q: Does the OUCC's review indicate that I&M needs additional revenue?

A: Yes. The OUCC recommends I&M's revenue be increased by no more than $1,732,530[10] as shown in OUCC witness Mark Garrett's testimony.

[10] Cause No. 45235, OUCC Direct Testimony of Witness Mark E. Garrett, p. 58.

V. NUCLEAR DECOMMISSIONING TRUST FUND

Q: Please describe I&M's proposal to increase the contribution made by Indiana ratepayers to its Nuclear DTF.

A: I&M is proposing to increase the funding level of the Nuclear DTF from $2 million to $10 million per year, which I&M states will increase the likelihood that adequate funds are available to decommission the plant and mitigate the risks associated with events that cannot be predicted.

Q: Does the OUCC support I&M's Nuclear DTF proposal?

A: No. I&M's proposed $10 million contribution is not necessary to meet the decommissioning requirements beginning in 2034 for D.C. Cook Unit 1 and 2037 for D.C. Cook Unit 2. My analysis shows that even the current contribution of $2 million[11] to the DTF only adds to a fund that is already overfunded.

Q: What amount is currently in the Nuclear DTF?

A: In response to an OUCC Data Request 25-01, I&M stated that as of June 30, 2019, the Nuclear DTF contained $2,455,996,212,[12] an increase of $297,592,734 or 12.12% over the December 31, 2018 Nuclear DTF balance of $2,158,403,478.[13] As of June 30, 2019, the Indiana Jurisdictional portion of the Nuclear DTF was $1,760,092,760[14] (71.66%), while the Michigan Jurisdictional portion was $448,933,118[15] (18.28%).

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[11] Cause No. 45235, Pre-Filed Verified Direct Testimony of Aaron L. Hill, p. 2, l. 8.
[12] Cause No. 45235, Attachment MDE-1.
[13] Cause No. 45235, Hill, p. 9, l. 23.
[14] Cause No. 45235, Attachment MDE-1.
[15] *Id.*

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

A: I&M's witness Roderick W. Knight testifies at pp. 12 – 13 (Table 2) that I&M's proposed total cost estimate for the decommissioning scenario is $2.032 billion in 2018 dollars. There is an additional cost estimate of approximately $43.2 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 $2.075 billion[16] – about $380 million less than the current balance of the DTF, $2,455,996,212.[17] In fact, the NRC 2017 Decommissioning Funding Status Report[18] shows the NRC Minimum, or Site Specific Cost Estimate, is $487,722,039 for D.C. Cook Unit 1 and $492,055,879 for Unit 2. This results in a total estimate of $979,777,918, which is more than a billion dollars less than I&M's current Nuclear DTF balance.

Q: Does the NRC audit I&M's Nuclear DTF?

A: Yes. Attached to my testimony are public audit reports available on the NRC website, which evaluate both the general status of the Nuclear DTF and the NRC's evaluation of the DTF for D.C. Cook Units 1 and 2. These NRC reports verify I&M's compliance with NRC decommissioning funding assurance requirements.[19] The following documents from the NRC website are attached to my testimony:

[16] Cause No. 45235, Pre-Filed Verified Direct Testimony of Roderick W. Knight, p. 12, Table 2.
[17] Cause No. 45235, Attachment MDE-1 (Petitioner's response to OUCC Data Request Set 25, Question 1(a).
[18] Cause No. 45235, Attachment MDE-2.
[19] Attachment MDE-4, p. 5, Conclusion sections, ("The staff also finds that all licensees are in compliance with the decommissioning funding assurance requirements of 10 CFR 50.75 and 10 CFR 50.82, as applicable, for the 2017 DFS reporting cycle.")

a. 2017 Decommissioning Funding Status Report - Power Reactor Decommissioning Funding Assurance as of December 31, 2016 (Attachment MDE-2);

b. Letter dated March 27, 2019, 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 MDE-3); and

c. Policy Issue (Information); dated August 6, 2018; Summary of Staff Review and of the 2017 Decommissioning Funding Status Reports from Operating and Decommissioning Power Reactor Licensees (Attachment MDE-4).

Q: Did you perform any other analysis regarding the Nuclear DTF?

A: Yes. I reviewed the total annual market value balances[20] as of December 31, 2018 for the seven year period 2012 through 2018. I then took the differences from year-to-year to detail how the Nuclear DTF performed on an annual basis. My analysis of the market value of the Nuclear DTF shows that, at current contribution levels, I&M's Nuclear DTF is expected to increase in value by over $100 million a year.

Q: How did the total market value of the Nuclear DTF perform over the last six years?

A: The Nuclear DTF increased annually on average by 7.77%, or $126.8 million per year.[21] The annual respective contributions from Michigan ($2.8 million)[22] and Indiana ($2 million)[23] are included in these totals.

Q: How did the total market value of the Nuclear DTF perform during the six month period January 1, 2019 through June 30, 2019?

A: The Nuclear DTF increased 13.79% (over $297.5 million[24]) during the six-month period. Contributions from Michigan and Indiana are included in these totals.

[20] Cause No. 45235, Attachment MDE-1.
[21] Cause No. 45235, Attachment MDE-5.
[22] Cause No. 45235, Pre-Filed Verified Direct Testimony of Aaron L. Hill, p. 5, l. 18.
[23] Cause No. 45235, Pre-Filed Verified Direct Testimony of Aaron L. Hill, p. 5, l. 6.

Indiana's and Michigan's ratepayer contributions are assessed on a monthly basis and reflected in the Nuclear DTF balance.

Q: What is the Indiana portion of the market value of the DTF at December 31, 2018 and 2020?

A: The existing Indiana market value for the Nuclear DTF at December 31, 2018 is $1,542,554,623.[25] That balance is estimated to grow to $1,747,011,865[26] for the forecasted test year ending December 31, 2020.

Q: Is there data available on the NRC website that projects the Nuclear DTF balance prior to decommissioning?

A: Yes. Referring to Attachment MDE-2, the projected Nuclear DTF balance prior to decommissioning is $699,079,244 for D.C. Cook Unit 1 and $686,747,364 for D.C. Cook Unit 2, for a total D.C. Cook nuclear power plant DTF projected balance of $1,385,826,608.

Q: Is there a need to increase the Indiana annual contribution to the Nuclear DTF to $10 million after the test year end, December 31, 2020?

A: No. Both the liquidated value of the Indiana portion of the estimated Nuclear DTF at December 31, 2037 and NRC's estimate in its 2017 Decommissioning Funding Status Report show there will be sufficient funds available as of December 31, 2037 to support a discontinuation of Indiana ratepayers' annual contribution to the Nuclear DTF in this case. Even Mr. Hill's testimony suggests that I&M's proposed $10 million increase is not needed; he states that continuing the $2 million annual contribution to the Nuclear DTF "is adequate for satisfying the expected future decommissioning obligation" of D.C. Cook Units 1 and 2. Hill, p.

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[24] Cause No. 45235, Attachment MDE-5
[25] Cause No. 45235, Attachment MDE-1.
[26] *Id.*

6, ll. 10-11.

Q: Should the current annual Indiana contribution of $2 million to the Nuclear DTF continue?

A: No. The liquidated value of the Nuclear DTF is more than sufficient without any further contributions. Asking customers to continue to contribute to the Nuclear DTF is unnecessary. Further, if the Nuclear DTF is over-funded, any refund during the remaining life of the units could be credited to ratepayers that have not contributed to the Nuclear DTF, resulting in generational inequity. Either circumstance is unnecessary and unreasonable.

Q: Will the Nuclear DTF stop earning interest when the decommissioning process begins?

A: No. Although any annual contributions to the Nuclear DTF will cease once the decommissioning process begins, the Nuclear DTF will continue to earn interest until it is depleted.

Q: If for some reason the Nuclear DTF balance does not cover decommissioning expenses, would Petitioner still be able to seek recovery of such expenses?

A: Yes. If a shortfall developed over the next 20 years, then Petitioner would still be able to seek recovery of all costs associated with the decommissioning.

VI. D.C. COOK NUCLEAR PLANT CLEAN WATER ACT RULE 316(B) STUDY EXPENSES

Q: What is Rule 316(b) under the Clean Water Act?

A: According to I&M Witness Lies, "The 316(b) Rule requires individual facilities, including D.C. Cook, to evaluate the mortality-related impacts of cooling water intake systems on large and small aquatic organisms."[27]

[27] Cause No. 45235, Prefiled Direct Testimony of Q. Shane Lies, p. 22, ll. 14-16.

Q: When was Rule 316(b) implemented?

A: The U.S. Environmental Protection Agency ("EPA") issued a final rule in October 2014 implementing Section 316(b).

Q: How much has I&M spent on studying Rule 316(b)?

A: Since 2008, I&M has spent $10.7 million on studies regarding Rule 316(b), and is proposing to create a regulatory asset and treat 316(b) study expenses as a rate base item.[28] I&M is proposing to amortize this amount over 15 years[29] ($713,792 annually) and is also seeking to earn a return on the unamortized amount by including the balance in rate base.[30]

Q: When did I&M begin incurring costs associated with Rule 316(b)?

A: I&M's response to OUCC Data Request Set No. 14, Question 1, shows I&M began incurring Rule 316(b) study expenses in August 2008, and continued to incur costs every year thereafter through 2018.[31] This shows costs were reoccurring in nature over the ten year period 2008 through 2018.

Q: Did I&M request Commission authorization to defer and amortize these costs when it first started to incur them?

A: No. I&M waited until the Rule 316(b) study was complete, and all study costs were incurred, before requesting Commission authority to defer these costs in the current rate proceeding. I&M witness Andrew Williamson states in testimony, "As a result, we are requesting recovery of the deferred cost by including it in rate base and amortizing over a period of 15 years."[32]

Q: How many rate cases has Petitioner filed since it began incurring these costs?

[28] Cause No. 45235, Prefiled Direct Testimony of Q. Shane Lies, pp. 23 - 25.
[29] Cause No. 45235, Prefiled Direct Testimony of Andrew J. Williamson, p. 19, ll. 18 - 20.
[30] Cause No. 45235, Petitioner's Exhibit A-5, p. 3 of 30, l. 7, column 14.
[31] Cause No. 45235, Confidential Workpaper MDE-1, p. 1 - 2.
[32] Cause No. 45235, Prefiled Verified Direct Testimony of Andrew J. Williamson, p. 29, ll. 16 - 18.

A: Petitioner has filed three rate cases since it began incurring these costs. (See Table 2).

TABLE 2 INDIANA MICHIGAN RATE CASE HISTORY		
Cause Number	**Prefile Date**	**Order Date**
44075	September 23, 2011	March 14, 2013
44967	July 26, 2017	May 30, 2018
45235	May 14, 2019	March 11, 2020[33]

Q: Was I&M been granted a level of embedded expense for compliance costs in a prior rate case?

A: Yes. In Cause No. 44075, the Commission rejected the OUCC's adjustment to eliminate a $1,775,761 compliance cost for the D.C. Cook Plant Fire Suppression System (NFPA 805 Costs) (Indiana - $1,148,122). The OUCC proposed that adjustment on the basis that the compliance cost was non-recurring. In denying the OUCC's adjustment, the Commission was persuaded by I&M's explanation that one-time compliance costs will be subsequently replaced by other one-time expenses in the future:

> We find I&M's explanation that one-time specific expenses incurred during the test year replaced one-time expenses that were incurred prior to the test year and will subsequently be replaced by new one-time expenses that will be incurred in the future and that these type expenses are properly included in operating expenses subject to rate recovery.[34]

[33] This date was determined by the Presiding Administrative Law Judge at the prehearing conference.
[34] Cause No. 44075, Commission Order, dated February 13, 2013, p. 92.

Therefore, I&M's rates since Cause No. 44075 have included an embedded level of compliance costs, on the presumption that as a one-time compliance cost falls away, another will replace it. I&M's 316(b) study costs should be treated as one of the "new one-time expenses" I&M has incurred after it stopped incurring other one-time compliance costs.

Q: Should D.C. Cook's Rule 316(b) studies be allowed deferred regulatory asset/liability treatment?

A: No. The 316(b) costs did not a constitute a financial impact to the utility as I&M was incurring these costs during the last two rate cases and did not seek recovery of them earlier. I&M had full control over when it started incurring Rule 316(b) study expenses, as well as when it decided to seek recovery of these expenses. I&M could have budgeted for, and sought recovery of, recurring Rule 316(b) study expenses in its post-2008 rate case proceedings (Cause Nos. 44075 and 44967).

Additionally, this cost is the type of compliance expense the Commission included in base rates to be replaced by new onetime expenses that will be incurred in the future. Therefore, I&M's rates already include an embedded level of compliance cost expense, and it would be inappropriate to provide I&M with additional recovery.

VII. NUCLEAR DECOMMISSIONING STUDY AND RATE CASE EXPENSE

Q: How is I&M proposing to treat the costs associated with the nuclear decommissioning study expenses and rate case expenses?

A: I&M is requesting to amortize costs associated with nuclear decommissioning study expenses and rate case expenses over two years. I&M is also seeking to earn a return on each of these expense accounts, by including the balances of each in rate base.

Q: Is it appropriate to include nuclear decommissioning study expenses and rate case expenses in rate base?

A: No. Rate base is the value of property used by the utility to provide service. Rate base does not include specific operating expenses. Rate base can include cash working capital. Working capital is usually determined through a lead/lag study, which considers the time value of money.

Q: Are rate case expense and nuclear decommissioning study expense rate base items or cash working capital items?

A: Rate case expense and nuclear decommissioning study expense are cash working capital items, and not rate base items. To even consider including these expenses in rate base, they should be reflected in part of a full cash working capital study where items such as utility expenses and property taxes are considered. These expenses should not be included in rate base as a single issue working capital requirement.

Q: What does the OUCC recommend regarding nuclear decommissioning study expenses and rate case expenses?

A: The OUCC recommends the Commission approve Petitioner's request to amortize these expenses, but deny Petitioner's request for rate base treatment for these expenditures. I&M's proposal to earn a return on these expenses goes beyond basic ratemaking principles and is unreasonable.

VIII. LIFE CYCLE MANAGEMENT RIDER

Q: Is the OUCC opposing Petitioner's proposals for the LCM Rider?

A: No.

IX. FUEL CLAUSE ADJUSTMENT RIDER

Q: Does the OUCC accept I&M's recommended base cost of fuel?

A: Yes. The OUCC accepts I&M's recommended base cost of fuel of $12.989 mills per kWh.[35]

Q: What changes does I&M propose to make in its FAC Rider filing?

A: I&M is proposing to use the FAC as the mechanism to track and provide a rate credit to reflect the revenues it will receive for renewable energy certificate ("REC") sales under I&M's proposed Green Power Rider ("GPR") tariff.

Q: Does I&M's proposal provide the OUCC extra time in the FAC Rider proceeding for the additional work of evaluating and addressing revenues from REC sales?

A: No. I&M has not proposed to allow the OUCC any extra time in the FAC proceeding. Under the statute, the OUCC only has twenty (20) days to review the FAC, and I&M is the only utility that files semi-annually, which requires the OUCC to review six (6) months of data in twenty (20) days. By agreement with Duke Energy Indiana, LLC, Indianapolis Power & Light Company, Northern Indiana Public Service Company, and Vectren South Electric, the OUCC has thirty-five (35) days after the utilities file their application and testimony to review three (3) months of data and file the OUCC's report and testimony. I&M's FAC proceeding is more involved, as it contains six months of data to review.

[35] Cause No. 45235, Prefiled Direct Testimony of Andrew J. Williamson, p. 45, l. 10.

Due to the short schedule, only one round of discovery is possible. Additionally, I&M is proposing to continue to include the GPR in the FAC proceeding. Therefore, should the Commission continue to allow I&M to include its GPR in its FAC filing, the OUCC requests the Commission make the approval contingent on I&M's agreement to allow the OUCC a minimum thirty-five (35) days to review I&M's FAC proceedings.

X. PURCHASED POWER OVER THE BENCHMARK

Q: Is I&M subject to the purchased power benchmark established in the Commission's Cause No. 41363 Order, dated August 18, 1999?

A: Yes. The Commission's March 4, 2009 Order in I&M's base rate case Cause No. 43306 sets the conditions and procedures for purchased power over the benchmark as originally required in Cause No. 41363.

Q: Have you read Mr. Williamson's purchased power over the benchmark testimony?

A: Yes. I generally agree with his opinions regarding the establishment of the purchased power over the benchmark. In addition, I&M offers all its generation into the PJM market and PJM controls the dispatch of I&M's generation. In essence, PJM controls the dispatch of I&M's generation, while I&M controls the generation availability and the day ahead offer price.

Q: Does the OUCC oppose I&M's request that the Commission permanently waive the generic purchased power procedures established in Cause No. 41363 as of the effective date of the Commission's Order in this Cause?

A: No. I&M's purchased power costs would continue to remain subject to OUCC review and Commission approval in I&M's FAC filings. However, the OUCC requests I&M continue to provide all internal, external, and root cause analyses for any forced outages greater than seventy-two (72) hours as part of its initial FAC audit package. Additionally, I&M should continue to provide its day ahead offers and the real time awards for the test days, requested by the OUCC, in its initial FAC audit package as well.

XI. RECOMMENDATIONS

Q: What do you recommend in this proceeding?

A: I recommend the Commission:

1) Deny Petitioner's request to increase the annual contribution to the Nuclear DTF by $8 million and reduce the current annual contribution to $0 after December 31, 2020;

2) Approve continuation of the LCM Rider;

3) Approve I&M's requested changes to the FAC, contingent on I&M agreeing to an extended filing time for the OUCC of a minimum 35 days;

4) Approve I&M's request for a permanent waiver of the purchased power over the benchmark;

5) Deny I&M's request to create a regulatory asset for D.C. Cook Nuclear Plant's Rule 316(b) study expenses, treat it as rate base, and amortize it over 15 years; and

6) Approve Petitioner's request to amortize nuclear decommissioning study expenses and rate case expenses, but deny Petitioner's request for rate base treatment of these expenditures.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A

Q: Please describe your educational background and experience.

A: I graduated from Purdue University in West Lafayette, Indiana in December 1986, with a Bachelor of Science degree, majoring in Accounting. I am licensed in the State of Indiana as a Certified Public Accountant. Upon graduation, I worked as a Field Auditor with the Audit Bureau of Circulation in Schaumburg, Illinois until October 1987. In December 1987, I accepted a position as a Staff Accountant with the OUCC. In May 1995, I was promoted to Principal Accountant and in December 1997, I was promoted to Assistant Chief Accountant. As part of the OUCC's reorganization, I accepted the position of Assistant Director of its Telecommunications Division in July 1999. From January 2000 through May 2000, I was the Acting Director of the Telecommunications Division. As part of an OUCC reorganization, I accepted a position as a Senior Utility Analyst. In September 2017 I accepted the position of Assistant Director in the Electric Division. As part of my continuing education, I have attended the National Association of Regulatory Utility Commissioner's ("NARUC") two-week seminar in Lansing, Michigan. I attended NARUC's spring 1993 and 1996 seminar on system of accounts. In addition, I attended several CPA sponsored courses and the Institute of Public Utilities Annual Conference in December 1994 and December 2000.

Q: Please describe the review and analysis you conducted in order to prepare your testimony.

A: I read I&M's Petition and prefiled testimony in this proceeding, as well as relevant Commission Orders. I reviewed Petitioner's workpapers and its Minimum Standard Filing Requirements ("MSFR") filing. In addition, I participated in the preparation of discovery questions, both formal and informal, and reviewed Petitioner's responses to OUCC questions and Intervenors' data requests.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 25
IURC CAUSE NO. 45235

DATA REQUEST NO OUCC 25-01

REQUEST

Please provide the following information for 1) total company; 2) Indiana Jurisdictional; and 3) Michigan Jurisdictional portions of the D.C. Cook Decommissioning Trust:

a. Balance of the D.C. Cook Decommissioning Trust as of December 31, 2018, March 31, 2019, and June 30, 2019;

b. Projected balance of the D.C. Cook Decommissioning Trust as of December 31, 2019; December 31, 2020, and December 31, 2021;

c. Balance of the D.C. Cook Decommissioning Trust as of 1) December 31, 2017; 2) December 31, 2016; 3) December 31, 2015; 4) December 31, 2014; 5) December 31, 2013; and 6) December 31, 2012;

d. If the balances provided in subpart a. contain annual contributions from Michigan and Indiana ratepayers, please provide the 1) total company; 2) Indiana Jurisdictional; and 3) Michigan Jurisdictional amounts contributed in each year;

e. 2018 annual contribution to the D.C. Cook Decommissioning Trust Fund;

f. 2019, 2020, and 2021 forecasted annual contribution to the D.C. Cook Decommissioning Trust Fund;

g. Annual earnings (dollars and percent) on the Balance of the D.C. Cook Decommissioning Trust as of 1) December 31, 2018; 2) December 31, 2017; 3) December 31, 2016; 4) December 31, 2015; 5) December 31, 2014; 6) December 31, 2013; and 7) December 31, 2012; and

h. Projected annual earnings (dollars and percent) on the Balance of the D.C. Cook Decommissioning Trust as of 1) December 31, 2019; 2) December 31, 2020; and 3) December 31, 2021.

i. Docket number and final order for Michigan Public Utility Commission ("PUC") proceeding that established the current annual contribution to the D.C. Cook Decommissioning Trust Fund for Michigan ratepayers.

RESPONSE

a.

Balances	Total Company	Indiana	Michigan
12/31/2018	$ 2,158,403,479	$ 1,542,554,623	$ 399,834,766
3/31/2019	$ 2,365,509,941	$ 1,695,257,783	$ 432,775,453
6/30/2019	$ 2,455,996,212	$ 1,760,092,760	$ 448,933,118

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 25
IURC CAUSE NO. 45235

b.

Balances	Total Company	Indiana	Michigan
12/31/2019	$ 2,299,399,569	$ 1,641,665,522	$ 425,811,956
12/31/2020	$ 2,448,320,812	$ 1,747,011,865	$ 453,276,390
12/31/2121	$ 2,605,912,184	$ 1,858,985,947	$ 482,313,215

c.

Balances	Total Company	Indiana	Michigan
12/31/2017	$ 2,215,858,794	$ 1,589,021,995	$ 406,432,282
12/31/2016	$ 1,945,738,907	$ 1,390,697,559	$ 363,467,065
12/31/2015	$ 1,797,432,092	$ 1,282,857,222	$ 339,177,370
12/31/2014	$ 1,786,696,775	$ 1,277,764,664	$ 335,983,478
12/31/2013	$ 1,622,790,606	$ 1,161,237,257	$ 306,132,035
12/31/2012	$ 1,397,612,009	$ 998,793,454	$ 266,538,210

d.

Contributions	Total Company	Indiana	Michigan
2018	$ 8,398,174	$ 3,166,667	$ 2,885,716
YTD 3/31/19	$ 1,783,908	$ 500,000	$ 750,668
YTD 6/30/19	$ 3,456,131	$ 1,000,000	$ 1,389,650

e.

Contributions	Total Company	Indiana	Michigan
2018	$ 8,398,174	$ 3,166,667	$ 2,885,716

f.

Forecasted Contributions	Total Company	Indiana	Michigan
2019	$ 7,138,306	$ 2,000,000	$ 2,796,051
2020	$ 6,357,894	$ 2,000,000	$ 2,796,051
2021	$ 5,824,139	$ 2,000,000	$ 2,796,051

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 25
IURC CAUSE NO. 45235

g.

	Total Company			Indiana			Michigan	
Annual Earnings	Dollars	Percent		Dollars	Percent		Dollars	Percent
2018	$ (57,257,682)	-2.66%	$	(44,691,038)	-2.82%	$	(8,230,232)	-2.01%
2017	$ 282,259,242	14.42%	$	208,107,292	15.00%	$	43,747,424	12.03%
2016	$ 153,154,649	8.38%	$	112,185,369	8.76%	$	23,640,564	6.96%
2015	$ 10,656,296	0.51%	$	6,368,925	0.50%	$	1,907,082	0.57%
2014	$ 162,579,271	9.95%	$	117,705,817	10.14%	$	28,278,427	9.20%
2013	$ 222,794,607	15.79%	$	162,065,896	16.21%	$	37,988,873	14.21%
2012	$ 107,203,776	8.21%	$	75,881,385	8.25%	$	19,978,537	8.14%

h.

Projected	Total Company			Indiana			Michigan	
Annual Earnings	Dollars	Percent		Dollars	Percent		Dollars	Percent
2019	$ 133,857,785	6.19%	$	97,110,899	6.29%	$	22,977,190	5.73%
2020	$ 142,563,349	6.19%	$	103,346,343	6.29%	$	24,464,434	5.73%
2021	$ 151,767,233	6.19%	$	109,974,082	6.29%	$	26,036,826	5.73%

i. Case No. U-15276. See “OUCC 25-01i U-15162 Order.pdf.”

TABLE 1

2017 DECOMMISSIONING FUNDING STATUS REPORT
for Operating Power Reactor Licensees (December 31, 2016)

Plant Name	Expected Shutdown Date as of 3/31/2017	Approx. No. of Years Remaining Before Expected Shutdown	Decommissioning Trust Fund (DTF) Balance (As of 12/31/16)	Projected DTF Balance[1] Before Decommissioning (2016$)	NRC Minimum[2] or Site-Specific Cost Estimate (SSCE[3]) (2016$)
Arkansas Nuclear One, Unit 1	05/20/2034	17	$466,300,000	$660,417,745	$450,023,926
Arkansas Nuclear One, Unit 2	07/17/2038	22	$368,400,000	$633,237,038	$468,608,006
Arnold (Duane) Energy Center	02/21/2034	17	$444,145,372	$677,415,095	$585,618,349
Beaver Valley Power Station, Unit 1	01/29/2036	19	$286,595,306	$419,649,610	$711,726,383 (SSCE)
Beaver Valley Power Station, Unit 2	05/27/2047	30	$378,702,702	$695,463,425	$481,865,787
Braidwood Station, Unit 1	07/29/2046	30	$322,022,000	$584,519,336	$492,055,879
Braidwood Station, Unit 2	10/17/2047	31	$348,139,000	$645,755,179	$492,055,879
Browns Ferry Nuclear Plant, Unit 1	12/20/2033	17	$341,250,600	$793,690,165	$642,093,163
Browns Ferry Nuclear Plant, Unit 2	06/28/2034	17	$332,599,271	$796,415,079	$642,093,163
Browns Ferry Nuclear Plant, Unit 3	07/02/2036	20	$301,524,766	$801,099,004	$642,093,163
Brunswick Steam Electric Plant, Unit 1	09/08/2036	20	$501,904,491	$744,774,169	$619,772,102
Brunswick Steam Electric Plant, Unit 2	12/27/2034	18	$554,893,905	$793,784,479	$619,772,102
Byron Nuclear Generating Station, Unit 1	09/16/2044	28	$353,618,000	$615,697,177	$492,055,879
Byron Nuclear Generating Station, Unit 2	08/02/2046	30	$340,758,000	$616,471,434	$492,055,879
Callaway Plant, Unit 1	10/18/2044	28	$446,444,950	$1,864,611,558	$492,055,879
Calvert Cliffs Nuclear Power Plant, Unit 1	07/31/2034	18	$358,696,000	$509,713,687	$456,881,370
Calvert Cliffs Nuclear Power Plant, Unit 2	08/13/2036	20	$459,606,000	$680,872,811	$456,881,370
Catawba Nuclear Station, Unit 1	12/05/2043	27	$397,017,662	$760,101,155	$449,502,529
Catawba Nuclear Station, Unit 2	12/05/2043	27	$398,905,102	$775,766,406	$449,502,529
Clinton Power Station, Unit 1	09/29/2026	10	$513,387,000	$623,823,594	$652,254,613
Columbia Generating Station	12/20/2043	27	$244,500,000	$623,663,351	$481,783,363
Comanche Peak Nuclear Power Plant, Unit 1	02/08/2030	13	$474,200,000	$794,814,101	$392,607,229
Comanche Peak Nuclear Power Plant, Unit 2	02/02/2033	16	$537,800,000	$898,472,009	$392,607,229
Cooper Nuclear Station	01/18/2034	17	$581,769,773	$891,329,227	$607,664,555
Davis-Besse Nuclear Power Station, Unit 1	04/22/2037	20	$552,423,474	$829,350,670	$467,638,661
Diablo Canyon Power Plant, Unit 1	11/02/2024	8	$1,201,600,000	$1,941,720,985	$494,417,329
Diablo Canyon Power Plant, Unit 2	08/26/2025	9	$1,571,000,000	$2,371,881,818	$494,417,329
Donald C. Cook Nuclear Power Plant, Unit 1	10/25/2034	18	$459,454,502	$699,079,244	$487,722,039
Donald C. Cook Nuclear Power Plant, Unit 2	12/23/2037	21	$418,248,246	$686,747,364	$492,055,879
Dresden Nuclear Power Station, Unit 2	12/22/2029	13	$651,199,000	$842,971,857	$631,058,754
Dresden Nuclear Power Station, Unit 3	01/12/2031	14	$665,882,000	$882,311,071	$631,058,754
Farley (Joseph M.) Nuclear Plant, Unit 1	06/25/2037	20	$402,098,838	$683,368,501	$458,423,281
Farley (Joseph M.) Nuclear Plant, Unit 2	03/31/2041	24	$388,100,905	$724,462,843	$458,423,281

1 Includes growth from earnings and contributions.
2 Derived from minimum formula at Title 10 of the *Code of Federal Regulations* (10 CFR) 50.75(c). Incorporates labor, energy, and low-level waste (LLW) burial escalation factors.
3 Four licensees provided SSCEs.
4 In years 2017 through 2022, licensee plans include significant contributions of approximately $600 million from a combination of Omaha Public Power District collections and a lump sum transfer from the Fort Calhoun Station, Unit 1, Supplemental Decommissioning Trust Fund.

2017 DECOMMISSIONING FUNDING STATUS REPORT for Operating Power Reactor Licensees (December 31, 2016)

Plant Name	Expected Shutdown Date as of 3/31/2017	Approx. No. of Years Remaining Before Expected Shutdown	Decommissioning Trust Fund (DTF) Balance (As of 12/31/16)	Projected DTF Balance[1] Before Decommissioning (2016$)	NRC Minimum[2] or Site-Specific Cost Estimate (SSCE[3]) (2016$)
Fermi, Unit 2	03/20/2045	28	$1,220,000,000	$2,149,316,422	$1,044,205,513
Fitzpatrick (James A.) Nuclear Power Plant	10/17/2034	18	$784,670,000	$1,120,615,113	$626,383,692
Fort Calhoun Station, Unit 1	12/31/2016	0	$285,838,000	$285,838,000 [4]	$931,973,000 (SSCE)
Ginna (Robert E.) Nuclear Power Plant	09/18/2029	13	$423,414,000	$546,283,548	$434,407,855
Grand Gulf Nuclear Station, Unit 1	11/01/2044	28	$844,900,000	$1,748,516,125	$642,093,163
Hatch (Edwin I.) Nuclear Plant, Unit 1	08/06/2034	18	$521,093,476	$759,852,063	$614,678,163
Hatch (Edwin I.) Nuclear Plant, Unit 2	06/13/2038	21	$471,737,376	$743,840,684	$614,678,163
Hope Creek Generating Station, Unit 1	04/11/2046	29	$536,295,000	$963,779,663	$1,080,204,000 (SSCE)
Indian Point Nuclear Generating, Unit 2	04/30/2020	3	$564,010,000	$602,858,889	$495,196,193
Indian Point Nuclear Generating, Unit 3	04/30/2021	4	$719,100,000	$784,145,786	$495,196,193
LaSalle County Station, Unit 1	04/17/2042	25	$476,685,000	$790,844,062	$652,254,613
LaSalle County Station, Unit 2	12/16/2043	27	$477,242,000	$817,220,477	$652,254,613
Limerick Generating Station, Unit 1	10/26/2044	28	$408,501,000	$959,233,937	$666,764,953
Limerick Generating Station, Unit 2	06/22/2049	32	$430,247,000	$1,173,496,388	$666,764,953
McGuire Nuclear Station, Unit 1	03/03/2041	24	$498,556,391	$809,415,989	$484,152,529
McGuire Nuclear Station, Unit 2	03/03/2043	26	$545,933,242	$922,474,457	$484,152,529
Millstone Power Station, Unit 2	07/31/2035	19	$614,000,000	$890,116,378	$440,838,021
Millstone Power Station, Unit 3	11/25/2045	29	$641,200,000	$1,142,750,488	$468,691,699
Monticello Nuclear Generating Plant, Unit 1	09/08/2030	14	$498,602,413	$656,275,125	$589,618,844
Nine Mile Point Nuclear Station, Unit 1	08/22/2029	13	$581,113,000	$748,497,367	$595,890,308
Nine Mile Point Nuclear Station, Unit 2	10/31/2046	30	$477,193,000	$866,178,509	$666,764,953
North Anna Power Station, Unit 1	04/01/2038	21	$380,700,000	$583,079,283	$465,118,419
North Anna Power Station, Unit 2	08/21/2040	24	$364,770,000	$585,347,885	$465,118,419
Oconee Nuclear Station, Unit 1	02/06/2033	16	$412,499,053	$569,807,223	$417,816,454
Oconee Nuclear Station, Unit 2	10/06/2033	17	$410,143,404	$574,151,493	$417,816,454
Oconee Nuclear Station, Unit 3	07/19/2034	18	$538,023,018	$764,540,714	$417,816,454
Oyster Creek Nuclear Generating Station	12/31/2019	3	$888,501,000	$932,931,000	$1,083,421,000 (SSCE)
Palisades Nuclear Plant	03/24/2031	14	$425,730,000	$565,985,300	$457,246,441
Palo Verde Nuclear Generating Station, Unit 1	06/01/2045	28	$966,731,000	$1,708,464,988	$494,417,329
Palo Verde Nuclear Generating Station, Unit 2	04/24/2046	29	$1,031,011,000	$1,852,837,402	$494,417,329
Palo Verde Nuclear Generating Station, Unit 3	11/25/2047	31	$1,009,047,000	$1,871,658,523	$494,417,329
Peach Bottom Atomic Power Station, Unit 2	08/08/2033	17	$565,607,000	$853,184,291	$666,764,953
Peach Bottom Atomic Power Station, Unit 3	07/02/2034	18	$586,693,000	$908,662,871	$666,764,953

1 Includes growth from earnings and contributions.
2 Derived from minimum formula at Title 10 of the *Code of Federal Regulations* (10 CFR) 50.75(c). Incorporates labor, energy, and low-level waste (LLW) burial escalation factors.
3 Four licensees provided SSCEs.
4 In years 2017 through 2022, licensee plans include significant contributions of approximately $600 million from a combination of Omaha Public Power District collections and a lump sum transfer from the Fort Calhoun Station, Unit 1, Supplemental Decommissioning Trust Fund.

2017 DECOMMISSIONING FUNDING STATUS REPORT
for Operating Power Reactor Licensees (December 31, 2016)

Plant Name	Expected Shutdown Date as of 3/31/2017	Approx. No. of Years Remaining Before Expected Shutdown	Decommissioning Trust Fund (DTF) Balance (As of 12/31/16)	Projected DTF Balance[1] Before Decommissioning (2016$)	NRC Minimum[2] or Site-Specific Cost Estimate (SSCE[3]) (2016$)
Perry Nuclear Power Plant, Unit 1	03/18/2026	9	$515,467,559	$620,124,568	$652,254,613
Pilgrim Nuclear Power Station	06/08/2032	15	$960,300,000	$1,362,333,603	$603,802,586
Point Beach Nuclear Plant, Unit 1	10/05/2030	14	$410,419,939	$541,107,110	$425,698,629
Point Beach Nuclear Plant, Unit 2	03/08/2033	16	$386,710,421	$535,074,299	$425,698,629
Praire Island Nuclear Generating Plant, Unit 1	08/09/2033	17	$358,639,700	$500,383,161	$420,626,236
Praire Island Nuclear Generating Plant, Unit 2	10/29/2034	18	$395,626,640	$565,008,465	$420,626,236
Quad Cities Station, Unit 1	12/14/2032	16	$642,578,582	$883,205,114	$631,058,754
Quad Cities Station, Unit 2	12/14/2032	16	$692,669,921	$952,054,167	$631,058,754
River Bend Station, Unit 1	08/29/2025	9	$712,800,000	$952,751,255	$626,963,546
Robinson (H.B.) Steam Electric Plant, Unit 2	07/31/2030	14	$567,362,845	$744,296,567	$409,189,430
Salem Nuclear Generating Station, Unit 1	08/13/2036	20	$609,543,000	$978,464,478	$468,691,699
Salem Nuclear Generating Station, Unit 2	04/18/2040	23	$522,417,000	$914,388,925	$468,691,699
Seabrook Station, Unit 1	03/15/2030	13	$650,671,791	$847,918,705	$503,341,699
Sequoyah Nuclear Plant, Unit 1	09/17/2040	24	$188,706,076	$617,218,777	$484,152,529
Sequoyah Nuclear Plant, Unit 2	09/15/2041	25	$179,770,274	$618,074,373	$484,152,529
Shearon Harris Nuclear Power Plant, Unit 1	10/24/2046	30	$492,852,452	$894,602,817	$465,443,031
South Texas Project, Unit 1	08/20/2027	11	$427,522,753	$554,442,462	$392,607,229
South Texas Project, Unit 2	12/15/2028	12	$521,377,891	$692,255,492	$392,607,229
St. Lucie Plant, Unit 1	03/01/2036	19	$1,014,177,909	$1,489,972,801	$468,364,546
St. Lucie Plant, Unit 2	04/06/2043	26	$974,637,287	$1,649,609,139	$468,364,546
Summer (Virgil C.) Nuclear Station, Unit 1	08/06/2042	26	$288,662,169	$535,727,919	$430,323,755
Surry Power Station, Unit 1	05/25/2032	15	$406,800,000	$560,636,237	$450,794,881
Surry Power Station, Unit 2	01/29/2033	16	$407,700,000	$569,801,321	$450,794,881
Susquehanna Steam Electric Station, Unit 1	07/17/2042	26	$551,104,747	$918,889,289	$666,764,953
Susquehanna Steam Electric Station, Unit 2	03/23/2044	27	$606,705,392	$1,045,854,722	$666,764,953
Three Mile Island Nuclear Station, Unit 1	04/19/2034	17	$625,913,000	$885,001,626	$467,860,424
Turkey Point Nuclear Generating, Unit 3	07/19/2032	16	$839,232,304	$1,145,841,732	$453,107,747
Turkey Point Nuclear Generating, Unit 4	04/10/2033	16	$948,100,859	$1,314,032,109	$453,107,747
Vogtle Electric Generating Plant, Unit 1	01/16/2047	30	$329,287,219	$644,938,354	$484,152,529
Vogtle Electric Generating Plant, Unit 2	02/09/2049	32	$326,615,373	$645,363,837	$484,152,529
Waterford Steam Electric Station, Unit 3	12/18/2024	8	$427,900,000	$564,502,446	$484,152,529
Watts Bar Nuclear Plant, Unit 1	11/09/2035	19	$239,158,220	$614,613,518	$484,152,529
Watts Bar Nuclear Plant, Unit 2	10/21/2055	39	$90,362,048	$627,320,193	$484,152,529
Wolf Creek Generating Station, Unit 1	03/11/2045	28	$444,676,000	$1,149,722,758	$492,055,879

1 Includes growth from earnings and contributions.
2 Derived from minimum formula at Title 10 of the *Code of Federal Regulations* (10 CFR) 50.75(c). Incorporates labor, energy, and low-level waste (LLW) burial escalation factors.
3 Four licensees provided SSCEs.
4 In years 2017 through 2022, licensee plans include significant contributions of approximately $600 million from a combination of Omaha Public Power District collections and a lump sum transfer from the Fort Calhoun Station, Unit 1, Supplemental Decommissioning Trust Fund.

AEP
INDIANA MICHIGAN POWER®
A unit of American Electric Power

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

AEP-NRC-2019-10
10 CFR 50.75(f)(1)

March 27, 2019

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 Director, at (269) 466-2649.

Sincerely,

Quinton S. Lies

Q. Shane Lies
Site Vice President

JMT/mll

Enclosure: Indiana Michigan Power Company, Donald C. Cook Nuclear Plant Units 1 and 2 2018 U. S. Nuclear Regulatory Commission Financial Assurance Requirements Report for Decommissioning Nuclear Power Reactors

A001
NRR

c: R. J. Ancona – MPSC
R. F. Kuntz – NRC Washington DC
MDEQ – RMD/RPS
NRC Resident Inspector
D. J. Roberts – NRC Region III
A. J. Williamson – AEP Ft. Wayne, w/o enclosure

ENCLOSURE TO AEP-NRC-2019-10

Indiana Michigan Power Company, Donald C. Cook Nuclear Plant Units 1 and 2
2018 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) is:

a.	Cook Unit 1	$512,446,094
b.	Cook Unit 2	$516,999,630
c.	Total	$1,029,445,724

   These cost estimates were determined using the burial cost escalation values and the methods outlined in NUREG-1307, Revision 17, 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, 2018, net of all taxes currently due for items included in 10 CFR 50.75(b) and (c) are:

a.	Cook Unit 1	$648,808,262
b.	Cook Unit 2	$590,864,127
c.	Total	$1,239,672,390

3. A schedule of the annual amounts to be collected for items in 10 CFR 50.75(b) and (c) are as follows:

   See Table 1 (attached) 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 Numbers U-15276 and U-18370 and the State of Indiana Cause Number 44967.

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 is 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 $871 million for Unit 1 and $840 million for Unit 2 net of tax at the time those units are shut down. These amounts are above the NRC minimum decommissioning cost estimates shown in item 1 above.

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
2019	$620,000	$930,000	$726,099	$2,276,099
2020	$620,000	$930,000	$484,171	$2,034,171
2021	$620,000	$930,000	$318,707	$1,868,707
2022	$620,000	$930,000	$318,707	$1,868,707
2023	$620,000	$930,000	$318,707	$1,868,707
2024	$620,000	$930,000	$318,707	$1,868,707
2025	$620,000	$930,000	$318,707	$1,868,707
2026	$620,000	$930,000	$308,246	$1,858,246
2027	$620,000	$930,000	$300,773	$1,850,773
2028	$620,000	$930,000	$300,773	$1,850,773
2029	$620,000	$930,000	$300,773	$1,850,773
2030	$620,000	$930,000	$300,773	$1,850,773
2031	$620,000	$930,000	$300,773	$1,850,773
2032	$620,000	$930,000	$300,773	$1,850,773
2033	$620,000	$930,000	$300,773	$1,850,773
10/25/2034	$516,667	$775,000	$111,483	$1,403,150

Unit 2

	Contributions			
	Indiana	Michigan	FERC	Total
2019	$620,000	$930,000	$726,099	$2,276,099
2020	$620,000	$930,000	$484,171	$2,034,171
2021	$620,000	$930,000	$318,707	$1,868,707
2022	$620,000	$930,000	$318,707	$1,868,707
2023	$620,000	$930,000	$318,707	$1,868,707
2024	$620,000	$930,000	$318,707	$1,868,707
2025	$620,000	$930,000	$318,707	$1,868,707
2026	$620,000	$930,000	$308,246	$1,858,246
2027	$620,000	$930,000	$300,773	$1,850,773
2028	$620,000	$930,000	$300,773	$1,850,773
2029	$620,000	$930,000	$300,773	$1,850,773
2030	$620,000	$930,000	$300,773	$1,850,773
2031	$620,000	$930,000	$300,773	$1,850,773
2032	$620,000	$930,000	$300,773	$1,850,773
2033	$620,000	$930,000	$300,773	$1,850,773
2034	$620,000	$930,000	$133,780	$1,683,780
2035	$620,000	$930,000	$50,739	$1,600,739
2036	$620,000	$930,000	$50,739	$1,600,739
12/23/2037	$620,000	$930,000	$50,739	$1,600,739

POLICY ISSUE
(Information)

August 6, 2018 SECY-18-0078

FOR: The Commissioners

FROM: Brian E. Holian, Acting Director
Office of Nuclear Reactor Regulation

SUBJECT: SUMMARY OF STAFF REVIEW AND FINDINGS OF THE 2017 DECOMMISSIONING FUNDING STATUS REPORTS FROM OPERATING AND DECOMMISSIONING POWER REACTOR LICENSEES

PURPOSE:

The purpose of this paper is to inform the Commission of the U.S. Nuclear Regulatory Commission (NRC) staff's findings from its review of the 2017 decommissioning funding status (DFS) reports submitted by operating power reactor licensees and power reactor licensees in decommissioning. This paper does not address any new commitments or resource implications.

BACKGROUND:

In 1988, the NRC established technical and financial requirements to assure that decommissioning of all licensed facilities would be accomplished in a safe and timely manner and that adequate licensee funds would be available for this purpose (Volume 53 of the *Federal Register* (FR), page 24018 (53 FR 24018); June 27, 1988). "Decommission," in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 50.2, "Definitions," 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

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301-415-2308

the property under restricted conditions and termination of the license. Therefore, decommissioning, as used in NRC regulations, refers exclusively to radiological decommissioning.

In 1998, in response to the anticipated deregulation of the power generating industry, the NRC amended the decommissioning financial assurance rules under 10 CFR 50.75, "Reporting and Recordkeeping for Decommissioning Planning," resulting in additional methods and flexibility for reactor licensees to provide financial assurance for decommissioning (63 FR 50465; September 22, 1998). Additionally, the amended regulations established the requirements that power reactor licensees report, on a biennial basis, the status of their decommissioning funds and on changes in their external trust agreements and other financial assurance mechanisms.

In 2011, the NRC further amended its regulations to improve decommissioning planning and to reduce the likelihood that any current operating facility would become a legacy site[1] (76 FR 35512; June 17, 2011). As a result, under 10 CFR 50.82, "Termination of License," power reactor licensees in decommissioning are required to provide annual DFS reports to the NRC that include, among other things, information on decommissioning expenditures made during the previous calendar year, the remaining balance of decommissioning funds, and an estimate of the cost to complete decommissioning.

DISCUSSION:

Pursuant to NRC regulations at 10 CFR 50.75(f)(1) (for operating power reactors) and 10 CFR 50.82(a)(8)(v)–(vi) (for power reactors in decommissioning), licensees are required to submit DFS reports to the NRC. DFS reports are required every 2 years from operating power reactor licensees, annually from operating power reactor licensees that are within 5 years of the projected end of their operation or involved in a merger or acquisition, and annually from power reactor licensees in decommissioning. Licensees must submit these reports to the NRC by March 31 of the reporting year. The report must provide specified information that will allow the agency to monitor the status of decommissioning funds for all power reactor licensees from the time they begin operating until their license is terminated.

For operating reactors, in accordance with 10 CFR 50.75(f)(1), the DFS reports must include: (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 on which the licensee is relying; (6) any modifications to a licensee's current method of providing financial assurance since the last submitted report; and (7) any material changes to trust agreements.

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 do provide assurance that licensees have available the bulk of the funds to safely decommission the facility. Adjustments to the

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1 As defined in the Statement of Considerations accompanying the 2011 rule, a "legacy site" is a facility that is in decommissioning status with complex issues and an owner who cannot complete the decommissioning work for technical or financial reasons.

certification amount are required annually over the operating life of the facility and account for inflation in the labor, energy, and waste burial components of decommissioning costs. Within 5 years before the projected end of operations, 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 use of a parent company guarantee, trust fund growth, or trust fund contributions. In any event, guidance in Regulatory Guide (RG) 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," Revision 2, issued October 2011, states that shortfalls identified in a biennial report must be corrected by the time the next report is due.

For power reactors in decommissioning, in accordance with 10 CFR 50.82(a)(8)(v), the DFS reports must include: (1) the amount spent on decommissioning, both cumulative and over the previous calendar year, the remaining balance of any decommissioning funds, and the amount provided by other financial assurance methods being relied on; (2) an estimate of the costs to complete decommissioning, reflecting any difference between actual and estimated costs for work performed during the year, and the decommissioning criteria on which the estimate is based; (3) any modifications to a licensee's current method of providing financial assurance since the last submitted report; and (4) any material changes to trust agreements or financial assurance contracts. Pursuant to 10 CFR 50.82(a)(8)(vi), if the sum of the balance of any remaining decommissioning funds, plus earnings on such funds calculated at not greater than a 2-percent real rate of return, together with the amount provided by other financial assurance methods being relied on, does not cover the estimated cost to complete the decommissioning, the DFS report must include additional financial assurance to cover the estimated cost of completion.

Pursuant to 10 CFR 50.75(e)(2), the NRC reserves the right to review, as needed, the rate of accumulation of decommissioning funds and take additional actions as appropriate, on a case-by-case basis, to ensure a licensee's adequate accumulation of decommissioning funds. This includes modification of a licensee's schedule for the accumulation of decommissioning funds. Additionally, in accordance with 10 CFR 50.82(c), for licensees that shut down their reactors prematurely, the collection period for any shortfall of funds will be determined on a case-by-case basis upon application by the licensee, taking into account the specific financial situation of each licensee.

Using staff guidance in Office of Nuclear Reactor Regulation Office Instruction LIC-205, "Procedures for NRC's Independent Analysis of Decommissioning Funding Assurance for Operating Nuclear Power Reactors and Power Reactors in Decommissioning," Revision 6, dated April 10, 2017,[2] the NRC staff reviewed the 2017 DFS reports for completeness and compliance with 10 CFR 50.75(f)(1) and 10 CFR 50.82(a)(8)(v)–(vi). The staff's review included reports for 100 operating power reactors and 20 power reactors in decommissioning. Two tables summarizing the staff's review are enclosed. Table 1, "2017 Decommissioning Funding Status Report for Operating Power Reactor Licensees (December 31, 2016)," summarizes the information from the 100 DFS reports submitted by operating power reactor licensees,[3] and

2 Agencywide Documents Access and Management System (ADAMS) Accession No. ML17075A095.
3 ADAMS Accession No. ML18096B543. On March 31, 2018, FirstEnergy Nuclear Operating Company

Table 2, "2017 Decommissioning Funding Status Report for Power Reactor Licensees in Decommissioning (December 31, 2016)," summarizes the information from the 20 reports submitted by power reactor licensees in decommissioning.[4]

Results of the NRC Staff's Review—Operating Power Reactor Licensees

The staff's review of the 2017 DFS reports for operating power reactor licensees resulted in the following findings:

- All 100 operating power reactor licensees demonstrated decommissioning funding assurance. Other than the discrepancy noted below for Donald C. Cook Nuclear Plant, Units 1 and 2, all operating power reactor licensees[5] met the reporting requirements of 10 CFR 50.75(f)(1).

- Three operating power reactors with shortfalls identified in the prior (2015) DFS review cycle (Braidwood Station, Units 1 and 2, and Byron Station, Unit 2) have since made up for those shortfalls. Exelon Generation Company, LLC (EGC), the licensee for each of these plants, received license renewal for the facilities, which provided for 20 years of additional trust fund growth. The Braidwood units received NRC license renewal in January 2016, and the Byron unit received NRC license renewal in November 2015.

- Indiana Michigan Power Company, the licensee for the Donald C. Cook Nuclear Plant, Units 1 and 2, demonstrated decommissioning funding assurance, meeting the NRC minimum funding requirement for both units. However, the licensee reported significant reductions in the balances of the decommissioning trust for both units (as compared to its 2015 submittal), totaling approximately $150 million, or $78 million and $72 million, respectively, despite overall market growth during this period.[6] On April 10, 2018, the NRC staff and licensee representatives held a Category I public meeting via teleconference.[7] In sum, the licensee stated that trust fund balances had increased as expected with market growth; however, some funds within the trust had been reallocated to pay for future spent fuel management expenses. The NRC has issued a request for additional information to the licensee for additional clarification and to address this discrepancy.[8]

(FENOC), FirstEnergy Nuclear Generation, LLC (FENGen), and its parent company FirstEnergy Solutions Corp. (FES), filed for bankruptcy under Chapter 11 of the United States Bankruptcy Code. ADAMS Accession No. ML18094A661. On April 25, 2018, FENOC certified to the NRC that it intends to permanently cease operations of its four nuclear power plants: Beaver Valley Power Station, Unit 1, Beaver Valley Power Station, Unit 2, Davis-Besse Nuclear Power Station, Unit 1, and Perry Nuclear Power Plant, Unit 1. FENOC's certification provided a revised schedule for the anticipated shutdown of its plants. ADAMS Accession No. ML18115A007. However, as noted above, the staff's analysis in Table 1 is based on the information provided by licensees in their 2017 DFS reports, including FENOC's March 2017 DFS report. ADAMS Accession No. ML17083B221. The staff continues to monitor FENOC's decommissioning funding to ensure adequate funding and compliance with decommissioning funding requirements.

4 ADAMS Accession No. ML18099A237.

5 Fort Calhoun Station stopped operations in October 2016 and transitioned to decommissioning at that time. Fort Calhoun will not appear among operating power reactor licensees in future DFS reports generated by the staff.

6 The March 21, 2017, DFS report for Donald C. Cook, Units 1 and 2, can be found at ADAMS Accession No. ML17081A443. The March 2015 submittal can be found at ADAMS Accession No. ML15084A007.

7 ADAMS Accession No. ML18109A069.

8 ADAMS Accession No. ML18142B531.

- Amounts accumulated in the decommissioning trust funds for operating power reactors totaled approximately $53.4 billion as of December 31, 2016.

Results of the NRC Staff's Review—Power Reactor Licensees in Decommissioning

The staff's review of the 2017 DFS reports for power reactor licensees in decommissioning resulted in the following findings:

- All 20 power reactor licensees in decommissioning met the reporting requirements of 10 CFR 50.82(a)(8)(v)–(vi).

- All 20 power reactor licensees in decommissioning demonstrated decommissioning funding assurance.

- One of the 20 power reactor licensees in decommissioning reported a shortfall. In its March 30, 2017, submittal,[9] EGC, the licensee for Peach Bottom Atomic Power Station, Unit 1 (PBAPS, Unit 1), identified, and the NRC staff confirmed, a shortfall in funding for PBAPS, Unit 1, of about $35 million (in 2016 dollars). EGC provided additional financial assurance to cover the estimated cost to complete decommissioning at PBAPS, Unit 1, pursuant to 10 CFR 50.82(a)(8)(vi) and guidance in RG 1.159. Specifically, the licensee indicated that collections from "non-bypassable charges"[10] from which EGC funds its decommissioning trust will be adjusted to cover any funding shortfall that exists. The NRC staff verified that the appropriate ratemaking authority, the Pennsylvania Public Utilities Commission, had approved an adjustment increasing the amount collected from non-bypassable charges to pay nuclear power plant decommissioning costs at the site. That adjustment, which went into effect on January 1, 2018, provides additional assurance that funding will be available to complete radiological decommissioning at PBAPS, Unit 1.

- Current balances in the decommissioning trust funds for power reactor licensees in decommissioning totaled approximately $6.5 billion as of December 31, 2016.

<u>CONCLUSION</u>:

Based on its review of the 2017 DFS reports, with the exception of the discrepancy noted above for Donald C. Cook Nuclear Plant, Units 1 and 2, the staff finds that all licensees are in compliance with the decommissioning funding assurance reporting requirements of 10 CFR 50.75(f)(1) for operating power reactor licensees and 10 CFR 50.82(a)(8)(v)–(vi) for power reactor licensees in decommissioning. The staff also finds that all licensees are in compliance with the decommissioning funding assurance requirements of 10 CFR 50.75 and 10 CFR 50.82, as applicable, for the 2017 DFS reporting cycle.

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9 ADAMS Accession No. ML17089A681.

10 The regulation at 10 CFR 50.2 states, "Non-bypassable charges mean those charges imposed over an established time period by a Government authority that affected persons or entities are required to pay to cover costs associated with the decommissioning of a nuclear power plant. Such charges include, but are not limited to, wire charges, stranded cost charges, transition charges, exit fees, other similar charges, or the securitized proceeds of a revenue stream."

COORDINATION:

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

/RA by Michele G. Evans for/

Brian E. Holian, Acting Director
Office of Nuclear Reactor Regulation

Enclosures:
2017 DFS Summary Table 1
2017 DFS Summary Table 2

SUBJECT: SUMMARY OF STAFF REVIEW AND FINDINGS OF THE 2017 DECOMMISSIONING FUNDING STATUS REPORTS FROM OPERATING POWER REACTOR LICENSEES AND POWER REACTOR LICENSEES IN DECOMMISSIONING DATED

ADAMS Accession Nos.:
PKG - ML18096B539
SECY Paper - ML18096B523
Enclosure 1 - ML18096B543
Enclosure 2 - ML18099A237

***Concurred via email**

OFFICE	**NRR/DLP/PFPB**	**NRR/DLP/PFPB**	**NRR/DLP/D***
NAME	RTurtil	ABowers	LLund (MJRoss-Lee for)
DATE	04/27/2018	05/23/2018	05/18/2018
OFFICE	**TechEd***	**OGC – NLO***	**NRR**
NAME	JDougherty	AGhosh	BHolian (MEvans for)
DATE	5/23/2018	06/21/2018	08/06/2018

OFFICIAL RECORD COPY

Nuclear Decommissioning Fund
Market Fund Growth

Date	Total Fund Market Value (a)	Increase from Previous Year ($)	Increase from Previous Year (%)
December 31, 2012	$1,397,612,009		
December 31, 2013	1,622,790,606	$225,178,597	16.11%
December 31, 2014	1,786,696,775	163,906,169	10.10%
December 31, 2015	1,797,432,092	10,735,317	0.60%
December 31, 2016	1,945,738,907	148,306,815	8.25%
December 31, 2017	2,215,858,794	270,119,887	13.88%
December 31, 2018	2,158,403,479	(57,455,315)	-2.59%
Total		$760,791,470.00	46.35%
Divide by 6 years		6	6
6 Year Average		$126,798,578	7.73%

Calculation of 6 Month Growth between December 31, 2018 and June 30, 2019

December 31, 2018	$2,158,403,479		
June 30, 2019	$2,455,996,212	$297,592,733	13.79%

Note A: Information from Indiana Michigan response to OUCC Data Request Set 25, Question 1.

AFFIRMATION

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

Michael D. Eckert

Michael D. Eckert
Assistant Director to the Electric Division
Indiana Office of Utility Consumer Counselor

Cause No. 45235
Indiana Michigan Power Company

August 20, 2019

Date

CERTIFICATE OF SERVICE

Indiana Office of Utility Consumer Counselor Public's Exhibit No. 1 Testimony of OUCC Witness Michael D. Eckert has been served upon the following parties of record in the captioned proceeding by electronic service on August 20, 2019.

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Deputy Consumer Counselor

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