ORIGINAL

Commissioner	Yes	No	Not Participating
Swinger			√
Bain	√		
Deig	√		
Jerrells	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE APPLICATION OF INDIANA MICHIGAN POWER COMPANY FOR APPROVAL OF A FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE APPLICABLE FOR THE BILLING MONTHS OF NOVEMBER 2026 THROUGH APRIL 2027; FOR CONTINUED RECOVERY OF THE COSTS OF WIND POWER PURCHASES PURSUANT TO CAUSE NOS. 43328, 43750, 44034, AND 44362; FOR CONTINUED RECOVERY OF THE COSTS OF EXCESS DISTRIBUTED GENERATION PURCHASES PURSUANT TO CAUSE NO. 45506; FOR CONTINUED RECOVERY OF THE ENERGY-RELATED COSTS OF COGENERATION PROJECT PURCHASES AND DEMAND RESPONSE PROGRAMS; AND FOR CONTINUED RECOVERY OF NET HEDGING COSTS	**CAUSE NO. 38702 FAC 97** **APPROVED: OCT 28 2026**

ORDER OF THE COMMISSION

Presiding Officers:
Joshua A. Bain, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On August 3, 2026, Indiana Michigan Power Company ("I&M" or "Petitioner") filed with the Indiana Utility Regulatory Commission ("Commission") its Verified Application and supporting case-in-chief testimony and exhibits. Petitioner filed corrections to its Verified Application and certain testimony on August 6, 2026.

On September 28, 2026, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its case-in-chief.

On September 30, 2026, the Commission issued a docket entry wherein the Presiding Administrative Law Judge requested I&M provide additional information. Petitioner responded on October 5, 2026.

On October 7, 2026, I&M filed a notice indicating it would not be filing rebuttal testimony.

An evidentiary hearing was held at 1:30 p.m. on October 14, 2026, in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana. Petitioner and the OUCC appeared and participated in the hearing by counsel, and the prefiled testimony and exhibits of the parties were admitted into evidence without objection.

The Commission, based upon the applicable law and the evidence of record, now finds as follows:

1. Notice and Jurisdiction. Notice of the hearing in this Cause was given and published as required by law. I&M is an Indiana corporation engaged in rendering electric utility service in the State of Indiana and is a public utility as defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to I&M's fuel cost charge. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. Petitioner's Characteristics. Petitioner is an Indiana corporation with its principal office in Fort Wayne, Indiana. It is a subsidiary of American Electric Power Company, Inc. Petitioner provides retail electric service to customers in Indiana and Michigan and owns, operates, manages, and controls plant and equipment used to generate, transmit, and distribute electric service.

3. Requested Relief. In its Verified Application, I&M seeks Commission approval to implement its proposed fuel adjustment cost ("FAC") during the billing months of November 2026 through April 2027, including a separately identified rate for gas transportation and reservation fees. I&M also requests continued approval of I&M's ratemaking treatment of wind power purchase costs, excess distributed generation costs, energy-related costs associated with cogeneration and demand response programs, and net hedging costs.

4. Fuel Purchases. Indiana Code § 8-1-2-42(d)(1) requires the Commission to find that the utility has made every reasonable effort to acquire fuel and generate or purchase power, or both, so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible.

A. Operations in PJM. Jason M. Stegall, Director of Regulatory Pricing for American Electric Power Service Corporation ("AEPSC"), testified that Petitioner meets its capacity obligations through a Fixed Resource Requirement plan. Petitioner therefore offers all of its available generation into, and purchases all its expected load from, the PJM Day-Ahead energy market each day. PJM's security-constrained economic dispatch model determines each unit's output, dispatching the least-cost units first. When Petitioner purchases more energy than it sells in an hour, the net purchase is recovered through the FAC.

Mr. Stegall testified that PJM Day-Ahead prices were generally steady, with a slight increase, during December 2025 through May 2026 ("reconciliation period"). Prices spiked in January 2026 during Winter Storm Fern and declined after February 2026 due to mild weather. He attributed the general increase in part to PJM's growing reliance on natural gas generation.

Mr. Stegall described the PJM market tools available to manage Rockport coal inventory, including increment pricing to conserve coal when inventory is low, and self-commitment or decrement pricing to increase coal burn when inventory approaches maximum safe storage levels. Petitioner did not use any of these tools to manage coal inventory during the reconciliation period because it did not project a coal shortage or an excess over safe storage limits. However, Rockport

Unit 1 was self-committed at times for required unit testing and near-term forecasted economics. Mr. Stegall testified that Petitioner has used, and may continue to use, increments to manage operational issues unrelated to coal inventory.

Mr. Stegall also testified that Petitioner acquired the Oregon Clean Energy Center ("Oregon") during the reconciliation period and is seeking approval to acquire the Big Sandy Peaking Plant ("Big Sandy") in Cause No. 46301 GRS 1. Costs for both gas-fired plants are included in the forecast for the period of November 2026 through April 2027 ("forecast period"). Beginning June 1, 2026, as presented in Cause No. 46305, Petitioner implemented a two-state PJM settlement process with separate Indiana Retail and Michigan Retail jurisdictions. Indiana-only resources, including Oregon and Big Sandy, are allocated 100% to Indiana, which will be reflected on an actual basis in future FAC filings.

B. Coal and Natural Gas. Clinton M. Stutler, Director of Natural Gas Procurement for AEPSC, testified that coal prices were relatively stable during the reconciliation period. Central Appalachian ("CAPP") coal ranged from $79.75 to $85.00 per ton and Powder River Basin ("PRB") coal from $14.80 to $15.65 per ton. Winter Storm Fern produced a small uptick in spot coal prices in late January and early February 2026, and the conflict between the United States and Iran tightened domestic coal supply as producers sought international margins. Winter Storm Fern had a significant effect on natural gas markets, including production freeze-offs of up to 15 billion cubic feet per day and a record 360 billion cubit foot storage withdrawal, with Upper Midwest spot prices approaching $60 per million British Thermal Units ("MMBtu").

Mr. Stutler testified that Rockport consists of two 1,300 megawatt ("MW") coal-fired units in Spencer County, Indiana. Petitioner complies with Rockport's sulfur dioxide limit of 0.15 lbs./MMBtu (30-day rolling average) and 10,000 tons per year by burning a blend of low-sulfur PRB and CAPP coal and complies with the Mercury and Air Toxics Standards using dry sorbent injection, activated carbon injection, and an electrostatic precipitator. Petitioner procures coal through requests for proposals and prompt market purchases, layering new agreements into its portfolio based primarily on price and quality and considering supplier financial status, ability to deliver, and past performance. Petitioner has not changed its coal procurement practices since Cause No. 38702 FAC 96 ("FAC 96") and has not entered into new or amended coal or coal transportation agreements for the forecast period. As of May 31, 2026, Rockport held 2.604 million tons of PRB coal and 101 thousand tons of CAPP coal.

Oregon is an 895 MW natural gas combined-cycle plant in Lucas County, Ohio. It holds firm transportation on the Generation Pipeline through May 31, 2032, and 66,000 MMBtu per day of firm capacity on Panhandle Eastern through June 30, 2029. Tenaska Marketing Ventures served as Oregon's fuel manager. Petitioner gave Tenaska termination notice on May 28, 2026, and assumed responsibility for Oregon's gas procurement and transportation effective gas day July 31, 2026. Going forward, Petitioner will issue requests for proposals for forward-month, fixed-price supply to mitigate spot price volatility, use daily spot purchases for incremental needs, and buy only from credit-approved counterparties.

C. Nuclear Fuel. Keith A. Steinmetz, Manager of Nuclear Engineering at the Cook Nuclear Plant, testified that both Cook units operated very well during the reconciliation period, with no planned refueling outages. He identified Petitioner's long-term contracts with Westinghouse (fabrication), the U.S. Department of Energy (spent fuel disposal), and LES/URENCO (enrichment), mid-term contracts with Cameco, ConverDyn, and Orano, and spot or short-term agreements with UG USA, WMC Energy, Itochu, and Moorstone. Projected spent nuclear fuel disposal costs are zero because the U.S. Department of Energy set the fee at 0.0 mills/kilowatt-hour ("kWh") effective May 16, 2014.

Mr. Steinmetz testified that six existing nuclear fuel leases, and an expected new lease for Unit 1 Batch 36 in October 2026, will affect forecast period costs. He explained I&M leases nuclear fuel because it is a lower-cost financing option than purchasing fuel with capital and estimated net savings from leases through June 2026 of $79.3 million. Because of uranium supply and price volatility, Petitioner began competitively purchasing uranium in 2023 to secure supply through 2028. Petitioner also minimizes nuclear fuel costs through long-term planning and competitive bidding, base-load operation of the Cook units, in-house neutronic analysis to optimize core loading, and a Nuclear Regulatory Commission approved quality assurance program for fuel vendors.

D. Delivered Fuel Costs. Petitioner's witnesses compared forecasted and actual delivered fuel costs for the reconciliation period as follows:

Fuel	Forecast	Actual
Rockport coal ($/ton)	41.68	40.24
Rockport coal (¢/MMBtu)	239.04	225.92
Oregon natural gas ($/MMBtu)	3.48	3.07
Cook Unit 1 nuclear fuel (¢/MMBtu)	72.00	69.57
Cook Unit 2 nuclear fuel (¢/MMBtu)	68.54	70.86

Rockport received 500,000 more tons than forecast, at lower mine and transportation costs per ton. Oregon's actual gas cost was $29,396,512 for 9,577,246 MMBtu, compared to a projection of $35,516,408 for 10,220,116 MMBtu. Mr. Stutler and Mr. Steinmetz each testified that Petitioner has prudently managed its fuel supply and made every reasonable effort to acquire fuel at the lowest cost reasonably possible.

OUCC witness Guerrettaz testified that Rockport Unit 1's weighted average delivered coal cost was $40.24/ton (225.92¢/MMBtu), compared to a forecast of $41.68/ton (239.04¢/MMBtu), due to better-than-forecast unit efficiency. He stated Petitioner did not use coal

increment/decrement pricing during the reconciliation period or in its forecast. Rockport's coal inventory was 2,287,000 tons as of September 8, 2026.

Based on the evidence presented, the Commission finds that Petitioner has made every reasonable effort to acquire fuel and generate or purchase power, or both, so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible, as required by Ind. Code § 8-1-2-42(d)(1).

5. Estimation of Fuel Costs. Indiana Code § 8-1-2-42(d)(4) requires the Commission to find that the utility's estimates of its prospective average fuel costs are reasonable, after considering the actual average fuel costs for prior periods and the accuracy of the utility's prior estimates.

Michael J. Stanek, Director of Supply Forecasting for AEPSC, sponsored Attachment 1-B, Schedule 2 of Petitioner's Exhibit 7, which presents Petitioner's forecasted monthly fuel costs and net energy requirements for the forecast period. He testified that the forecast uses the Federal Energy Regulatory Commission ("FERC") Net Energy Cost method and includes Account 151 fossil fuel and Account 518 nuclear fuel costs, the allowable portion of purchased power, wind purchase costs consistent with Cause Nos. 43328, 43750, 44034, and 44362, and cogeneration energy costs approved in Cause No. 38702 FAC 91. Costs of supplying energy to non-affiliates are removed.

Mr. Stanek testified that Petitioner is not changing its forecast methodology in this filing but is updating its forecast to align with its state-specific planning process and the Commission's Order in Cause No. 46305 and will reflect those updates in a future FAC filing. Mr. Stanek testified that total company fuel costs on an Indiana basis are projected to be $332 million, or 21.02 mills/kWh before line losses, based on a net energy requirement of 15,810 gigawatt-hour.

Mr. Stanek testified that actual FAC costs for the reconciliation period differed from forecast by 18.63%, as shown on Attachment 1-D of Petitioner's Exhibit 7, in part because of increased inter-system sales. He testified that the forecast was reasonable when made, and that the projections for the forecast period are reasonable because they reflect historical unit performance, scheduled maintenance outages, economic power purchases, and off-system sales, consistent with the methodology the Commission has previously found reasonable.

OUCC witness Gregory T. Guerrettaz, a certified public accountant, testified that Petitioner forecasts fuel costs using the PLEXOS model. He said the OUCC reviewed each month's output and found the forecasted fuel prices similar to those at the audit date. Petitioner's forecasted F÷S of 21.783 mills/kWh is the highest in its recent history. He noted Petitioner attributed the increase to higher market prices and agreed to include natural gas price forwards in its forecast workpapers. Mr. Guerrettaz concluded that I&M's forecast is reasonable, subject to the large load materializing.

Based on the evidence presented, and having considered Petitioner's actual average fuel costs for prior periods and the accuracy of its prior estimates, the Commission finds that Petitioner's estimates of its prospective average fuel costs for November 2026 through April 2027 are reasonable. Additionally, considering the addition of Oregon and Big Sandy to Petitioner's

generation portfolio, we agree Petitioner should include natural gas price forwards in its forecast workpapers in future FAC filings.

6. Operating Expenses. Indiana Code § 8-1-2-42(d)(2) requires the Commission to find that actual increases in fuel costs have not been offset by actual decreases in other operating expenses.

Jennifer C. Goodin, Director of Regulatory Services for I&M, testified that the Indiana fuel costs included in Petitioner's most recent base rate case, Cause No. 45933, were $229,484,000. Petitioner's Indiana total fuel costs for the 12 months ended May 31, 2026, were $357,309,000, before allocation of fuel to wholesale deliveries. Petitioner's Exhibit 7, Attachment 1-F, Schedule 1 (Corrected), Column 8, Line 42. Ms. Goodin further testified that Indiana retail non-fuel expenses also increased over the same period. Those expenses were $1,481,889,000 for the 12 months ended May 31, 2026, compared to $1,044,127,000 in Cause No. 45933. *Id.* at Line 41.

Based on the evidence presented, the Commission finds that Petitioner's increases in fuel costs have not been offset by decreases in other operating expenses. The requirements of Ind. Code § 8-1-2-42(d)(2) are satisfied.

7. Return Earned. Indiana Code § 8-1-2-42(d)(3) requires the Commission to find that the proposed fuel charge will not result in Petitioner earning a return in excess of the return authorized in its last rate proceeding. Indiana Code § 8-1-2-42.3 further addresses the sum of the differentials between actual and authorized returns over the relevant period.

A. Oregon Clean Energy Center – Cause No. 46217. The Commission's Order in Cause No. 46217 ("46217 Order") approving a settlement agreement authorized Petitioner to use deferral accounting to record the net of: (1) revenues from new large load customers, limited to the amount by which actual net operating income ("NOI") exceeds authorized NOI, and (2) incremental costs, operation and maintenance expenses, and the return on and of Oregon not recoverable through existing riders. The deferral authority began on the first day of the month in which Oregon was acquired and expires upon implementation of new base rates in Petitioner's next rate case.

Ms. Goodin testified that Petitioner acquired Oregon in March 2026 and implemented the deferral authority beginning March 1, 2026. She testified that Petitioner excluded costs already recovered through riders, reported Oregon revenues and expenses separately in Columns 5 and 6 of Petitioner's Exhibit 7, Attachment 1-F, Schedule 1, and provided supporting workpapers. As of May 31, 2026, the net deferral balance was as follows:

Deferral component	Amount at May 31, 2026
Large Load Deferral (regulatory liability)	$49,997,000
Less: Oregon Revenue Requirement Deferral	($25,049,000)
Net regulatory liability	$24,948,000

The 46217 Order also authorized Petitioner to increase its authorized NOI to reflect Oregon's incremental average rate base. The approved annual increase is $54,761,487 after tax, or $4,563,000 per month. Petitioner reflected an adjustment of $13,690,000 for March through May 2026. This adjustment expires prospectively upon implementation of new base rates.

OUCC witness Guerrettaz testified that the OUCC will need to review how Oregon is offered into PJM and how Petitioner manages its gas supply contracts. He noted that Petitioner entered into a new natural gas contract for Oregon and cancelled the prior contract. Because the new contract was not available at the time of the audit, Mr. Guerrettaz expressed no opinion on it.

The Commission finds that Petitioner's treatment of the Oregon deferrals and authorized NOI adjustment in this proceeding is consistent with the 46217 Order.

B. Authorized NOI. Ms. Goodin testified that Petitioner's authorized NOI for the 12 months ended May 31, 2026, was $384,730,000. Petitioner's Exhibit 7, Attachment 1-F, Schedule 1 (Corrected), Column 9, Line 39. That amount consists of the authorized NOI approved in Cause No. 45933 as well as adjustments approved by the Commission in Cause Nos. 46080, 46217, 38702 FAC 96, 45546, 45576, 45868, 46088, and 46083. Petitioner also excluded Demand Side Management/Energy Efficiency Shared Savings and Demand Response Financial Incentive of $2,091,589 from actual NOI for earnings test purposes, as addressed in Cause Nos. 45933, 45701, and 46255.

C. Actual NOI. Ms. Goodin testified that Petitioner's actual NOI for the 12 months ended May 31, 2026, was $533,870,000. After deducting the Large Load Deferral of $49,997,000, Petitioner's adjusted NOI was $483,873,000. Petitioner's Exhibit 7, Attachment 1-F, Schedule 1 (Corrected), Column 8, Lines 36–38. Actual NOI therefore exceeded authorized NOI by $99,143,000.

D. Sum of the Differentials. Ms. Goodin testified that the sum of the differentials for the relevant period, Cause No. 38702 FAC 88 through FAC 97, is $326,724,000, which is greater than zero. Petitioner's Exhibit 7, Attachment 1-F, Schedule 4 (Corrected). Because the sum of the differentials exceeds the current-period over-earnings, Section I.B. of the Settlement Agreement approved in Cause No. 43774 PJM 15 does not apply.

E. FAC Reduction. The reduction amount is the lower of the 12-month over-earnings or the sum of the differentials for the relevant period. The lower amount is the 12-month over-earnings of $99,143,000. Because Petitioner files semi-annual FAC proceedings, Petitioner divided that amount in half, producing an FAC reduction of $49,571,000, or $66,004,000 grossed up for taxes. Petitioner's Exhibit 7, Attachment 1-F, Schedule 5 (Corrected).

F. OUCC Testimony. Mr. Guerrettaz agreed that Petitioner's adjusted NOI of $483,873,000 exceeded its authorized NOI of $384,730,000 by $99,143,000, producing a grossed-up reduction of $66,004,000. He confirmed the sum of the differentials for the relevant period of $326,724,000. He also confirmed that Petitioner had no decreases in other operating expenses to offset its fuel cost increases. He testified that the figures in Petitioner's revised application were supported by its books and records.

Based on the evidence presented, the Commission finds that Petitioner earned a return in excess of its authorized return during the 12 months ended May 31, 2026, and that the sum of the differentials for the relevant period is greater than zero. The Commission further finds that Petitioner's proposed FAC reduction of $49,571,000 ($66,004,000 grossed up for taxes) is reasonable and should be approved.

8. Nuclear Production Tax Credits. Ms. Goodin testified that the Cook Plant qualifies for transferable nuclear production tax credits ("PTCs") for tax years 2024 through 2032. Petitioner estimated PTCs of $56,721,000 on a total company basis and included $40,494,000 as the Indiana jurisdictional portion for the period ending May 31, 2026. Petitioner's Exhibit 7, Attachment 1-F, Schedule 1 (Corrected), Line 29. Because the Internal Revenue Service has not yet issued guidance on calculating the credit, Petitioner proposes to reconcile any difference between the estimate and the actual value in a future FAC proceeding.

The Commission finds that Petitioner's inclusion of estimated nuclear PTCs in the earnings test is reasonable, subject to reconciliation in a future FAC proceeding once the actual value is known.

9. Jurisdictional Cost Allocation. Ms. Goodin testified that, as authorized in the Settlement Agreement approved in FAC 96, Petitioner allocated total company costs to the Indiana jurisdiction as follows: (1) generation-related costs were allocated using monthly updated demand and energy allocation factors, consistent with the monthly studies used to allocate PJM and Off-System Sale costs under the Settlement Agreements approved in Cause Nos. 43774 PJM 15 and PJM 16; and (2) remaining costs were allocated at the FERC-account level using the jurisdictional allocation factors approved in Cause No. 45933.

Ms. Goodin further testified that the earnings test reflects the reallocation of OVEC capacity, energy, and associated costs, and of short-term capacity purchases, approved in the Commission's July 23, 2025 Order in Cause No. 45164 RA 5, effective June 1, 2025.

The Commission finds that Petitioner's jurisdictional allocation in this proceeding is consistent with the Commission's Orders in Cause Nos. 38702 FAC 96, 43774 PJM 15 and PJM 16, and 45164 RA 5.

10. Reconciliation of Fuel Costs. Jason E. Walcutt, Regulatory Consultant Staff, testified in support of the calculation of the FAC factor. He testified that Petitioner continues its semi-annual FAC filing schedule, which the Commission has approved since 1999. Mr. Walcutt explained that semi-annual filings spread unpredictable forecast variances, such as forced outages, over six months and promote rate stability. Petitioner also provides the OUCC with quarterly workpapers on an interim basis.

A. Variance. Mr. Walcutt testified that the variance component recognizes any over- or under-recovery by comparing incremental fuel costs incurred to fuel revenues collected in each month of the reconciliation period. Petitioner's fuel costs were $46,576,990 less than projected, which reduces the FAC factor by (3.828) mills/kWh. Petitioner's Exhibit 7, Attachment

1-B, Schedule 1 (Corrected), Line 30. Mr. Walcutt testified that the forecast for the reconciliation period was reasonable when made.

OUCC witness Guerrettaz testified that the $46,576,990 over-recovery is the largest variance he can recall, compared to $4,498,138 in FAC 96. He noted that Petitioner attributed it primarily to certain large load customers purchasing less energy than forecast, which overstated FAC 96 sales and fuel costs. He also testified that Petitioner agreed to analyze its large load forecast, compare actual to forecasted large load usage, and provide additional information in its next FAC filing.

B. Hedging. Mr. Walcutt testified that Petitioner uses hedging, occasionally including financial power purchases, to reduce the effect of PJM spot energy price volatility on its open energy position. Petitioner realized a hedging credit of ($11,430) during the reconciliation period. Petitioner's Exhibit 7, Attachment 1-C. The running total of financial power hedging activity included in the FAC since Cause No. 38702 FAC 92 is $3,457,207.

C. Credits Included in the Variance. Mr. Walcutt testified that the variance component includes: (1) net revenues from Petitioner's GoGreen Rider; (2) net revenues from the sale of Renewable Energy Credits; (3) an annual revenue credit for the sale of Emission-Free Energy Certificates from the Cook Plant to Steel Dynamics, Inc.; and the second $1,000,000 installment of the $2,000,000 residential credit agreed to in the Settlement Agreement in FAC 96. Mr. Walcutt further testified that the projected factor reflects the Commission's Orders in Cause No. 43401 (Steel Dynamics, Inc.) and Cause No. 45661 (Voluntary Curtailment Service), although no customers currently participate in the Voluntary Curtailment Service program.

The Commission finds that Petitioner's reconciliation of fuel costs for December 2025 through May 2026, including the credits described above, is reasonable and consistent with prior Commission Orders. We also note that I&M has agreed to review its large load forecast and provide additional information in its next FAC filing. Additionally, if Petitioner changes its large load forecast methodology, it should file testimony in that FAC proceeding explaining why and how the methodology was changed in future FAC filings.

11. Proposed FAC Factors.

A. Two-Part Rate Design. Mr. Walcutt testified that, beginning with this FAC and consistent with the Commission's Orders in Cause Nos. 46217 and 46301, Petitioner is implementing a two-part rate design for its fuel factor beginning with the November 2026 billing month. Gas transportation and reservation fees are allocated among tariff classes using the demand and energy allocation methods approved in Cause No. 45933, including the class coincident peak per-kWh ratio method. Energy factors are then calculated from each class's forecasted billing energy for November 2026 through April 2027. Demand charges are calculated for the GS, LGS, IP, and EHG classes from projected billing demands over the same period.

B. Proposed Factors. Petitioner requests approval of the FAC factors for billing cycles in November 2026 through April 2027 (see Table JEW-1):

Tariff class	Energy fuel costs (¢/kWh)	Gas transp./reservation fees (¢/kWh)	Gas transp./reservation fees ($/kW)
RS, RS-TOD, RS-TOD2, RS-OPES, RS PEV, RSD, RS CPP	(0.1670)	0.1620	—
GS (up to 4,500 kWh)	(0.1219)	0.1315	—
GS (over 4,500 kWh), LGS, LGS-TOD	(0.1219)	—	0.401
GS (over 10 kW), LGS, LGS-TOD	(0.1219)	—	0.401
GS-LM-TOD, GS-TOD2, GS Unmetered, GS-TOD, GS-PEV, Public and Fleet PEV, GS-CPP, LGS-LMTOD	(0.1219)	0.1315	—
IP, CS-IRP2	(0.1219)	—	0.549
MS	(0.1219)	0.1584	—
WSS	(0.1219)	0.0981	—
IS	(0.1219)	0.0564	—
EHG	(0.1219)	—	0.339
OL	(0.1219)	0.0071	—
SLS, ECLS, SLC, SLCM, FW-SL	(0.1219)	0.0075	—

In addition to the non-residential energy fuel factor in the chart above, Petitioner also requests approval of a separately identified rate for gas transportation and reservation fees applicable to a special contract customer. *See* Petitioner's Exhibit 7-C, Attachment 1-B, Schedule 3.

OUCC witness Guerrettaz testified that Petitioner revised its proposed factor from (1.734) to (1.670) mills/kWh after correcting an error in its earnings test calculation. He provided Schedule A showing a projected fuel cost (F÷S) of 21.783 mills/kWh, less a base cost of fuel of 12.981 mills/kWh. That difference of 8.802 mills/kWh is reduced by a variance factor of (3.828), an earnings reduction factor of (5.425) based on the $66,004,000 grossed-up over-earnings, an OVEC reduction factor of (0.767) based on $9,330,925, and residential-specific adjustments, producing a factor of (1.670) mills/kWh. Each factor is based on 12,166,000 MWh.

OUCC witness Michael D. Eckert, Chief Technical Advisor in the OUCC's Electric Division, testified that he did not oppose Petitioner's proposed factors. He recommended that the Commission require Petitioner to (1) provide information on its coal inventory and how it proposes to address that inventory, and (2) file testimony, if necessary, explaining why and how its large load forecast methodology should be changed. He also recommended that Petitioner file testimony,

schedules, and workpapers justifying any future use of coal increment/decrement pricing in its next FAC filing.

C. Bill Impact. Mr. Walcutt testified that approval of the proposed factors will decrease the monthly bill of a typical residential customer using 1,000 kWh by $1.98, or 1.22%, compared to the factor currently in effect.

D. System Losses. Petitioner's Exhibit 7, Attachment 1-G calculates average system losses for calendar year 2025. That loss factor will be used to calculate actual incurred fuel costs for July 2026 through June 2027.

The Commission finds that Petitioner's proposed FAC factors, including the two-part rate design and the special contract rate, are calculated consistent with the Commission's Orders in Cause Nos. 45933, 46217, and 46301 and should be approved. In addition, as recommended by the OUCC, Petitioner shall continue to provide information in its FAC filings on its coal inventory, projected coal burn, and coal purchases, and on how it proposes to address its coal inventory level. If Petitioner uses coal increment/decrement pricing in a future reconciliation period, it shall support that use with testimony, schedules, and workpapers in the corresponding FAC filing.

12. Confidentiality. On August 4, 2026, I&M filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information, supported by the Affidavit of Jason E. Walcott, showing certain information to be submitted to the Commission contains trade secret information that is not known or readily available to persons outside of I&M. A docket entry was issued on August 13, 2026, finding this information should be held confidential on a preliminary basis, after which the information was submitted under seal.

Subsequent to the evidentiary hearing on October 21, 2026, I&M filed a Second Motion for Protection and Nondisclosure of Confidential and Proprietary Information, supported by the Affidavit of Jason E. Walcott, showing certain information that had been submitted to the Commission in Petitioner's Exhibit 8 contains trade secret information that is not known or readily available to persons outside of I&M, and requesting that such information be exempted from public access and held confidential. A docket entry was issued the same day, finding the information should be held confidential on a preliminary basis.

After reviewing the information, the Commission finds the information qualifies as confidential trade secret information as defined in Ind. Code § 24-2-3-2; consequently, this information shall continue to be held as confidential and protected from public access and disclosure by the Commission and is exempted from public access requirements contained in Ind. Code §§ 5-14-3-4 and 8-1-2-29. The confidential portion of Petitioner's Exhibit 8 shall be identified and marked as Petitioner's Exhibit 8-C in the record.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Petitioner's requested FAC factors set forth in Finding Paragraph 11, including the two-part rate design and the special contract rate, for the billing months of November 2026 through April 2027, reflecting an FAC reduction of $49,571,000 ($66,004,000 grossed up for taxes), are approved.

2. Petitioner's implementation of deferral accounting and authorized NOI adjustment approved in Cause No. 46217, as reflected in this proceeding, is approved.

3. I&M's ratemaking treatment for the cost of wind power purchases pursuant to the Commission's Orders in Cause Nos. 43328, 43750, 44034, and 44362 is approved, and I&M's ratemaking treatment for cogeneration, distributed generation, demand response, and hedging activity pursuant to previous Commission orders in Cause Nos. 44696, 45506, and 38702 is approved.

4. Petitioner shall reconcile the estimated nuclear production tax credits included in this proceeding in a future FAC proceeding once the actual value is known.

5. Petitioner has agreed to review its large load forecast and provide additional information in its next FAC filing. Additionally, if Petitioner changes its large load forecast methodology, it shall file testimony explaining why and how the methodology was changed in future FAC filings.

6. Petitioner shall include natural gas price forwards in its forecast workpapers in future FAC filings.

7. Petitioner shall continue to provide information in its FAC filings on its coal inventory, projected coal burn, and coal purchases, and on how it proposes to address its coal inventory level.

8. If Petitioner uses coal increment/decrement pricing in a future reconciliation period, it shall support that use with testimony, schedules, and workpapers in the corresponding FAC filing.

9. Prior to implementing the factors approved in this Order, Petitioner shall file the applicable rate schedules under this Cause for approval by the Commission's Energy Division.

10. The information submitted by Petitioner pursuant to a preliminary finding of confidentiality is determined to contain trade secret information as defined in Ind. Code § 24-2-3-2 and, therefore, shall be excepted from public access under Ind. Code §§ 8-1-2-29 and 5-14-3-4.

11. This Order shall be effective on and after the date of its approval.

BAIN, DEIG, JERRELLS, AND ZIEGNER CONCUR; SWINGER ABSENT:

APPROVED: OCT 28 2026

I hereby certify that the above is a true and correct copy of the Order as approved.

Regina K Joyner Digitally signed by Regina K Joyner Date: 2026.10.28 10:52:22 -04'00' on behalf of

Dana Kosco
Secretary of the Commission