STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

DUKE ENERGY INDIANA, LLC'S SUBMISSION OF
CORRECTED TESTIMONY OF SUZANNE E. SIEFERMAN

Petitioner Duke Energy Indiana, LLC ("Duke Energy Indiana"), by counsel, respectfully submits Corrected Exhibit 5, sub-exhibit 5-C, and Corrected Exhibit 36 of the prefiled testimonies of Suzanne E. Sieferman. The corrections are to remove references to the Company's request for deferral of O&M costs associated with the Electric Transportation Pilot Program, as this is issue has been moved to the 45253 S2 subdocket. Attached are redlined and clean versions of Ms. Sieferman's Corrected direct and rebuttal testimonies (Attachments 1 through 4).

Respectfully submitted,

DUKE ENERGY INDIANA, LLC

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing was electronically delivered this 21st day of January 2020 to the following:

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CORRECTED DIRECT TESTIMONY OF SUZANNE E. SIEFERMAN, DIRECTOR, RATES AND REGULATORY PLANNING ON BEHALF OF DUKE ENERGY INDIANA, LLC BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Suzanne E. Sieferman, and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company") as Director, Rates and Regulatory Planning. Duke Energy Indiana is a wholly owned, indirect subsidiary of Duke Energy Corporation.

Q. PLEASE DESCRIBE YOUR DUTIES AS DIRECTOR, RATES AND REGULATORY PLANNING.

A. I am responsible for the preparation of financial and accounting data used in Company rate filings and petitions for changes in fuel cost adjustment factors and other tracking mechanisms.

Q. PLEASE STATE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I am a graduate of Indiana University, holding a Bachelor of Science Degree in Business, with a major in Accounting. I am a Certified Public Accountant ("CPA") and a member of the Indiana CPA Society. Since my employment with the Company in 1990, I have held various financial and accounting positions supporting the Company and its affiliates. Prior to my move to the Rates and

Regulatory Planning department in 2008, I held positions in Benefits Accounting, Corporate Accounting, Business Unit Financial Reporting and External Reporting groups.

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

A. My testimony will: 1) address certain rate base and operating income *pro forma* adjustments applicable to the twelve months ended December 2020 forecasted test period ("Test Period"); 2) explain and support proposed changes to certain of the Company's existing rate adjustment riders to be effective with the implementation of the Company's revised base rates, including the determination of the base cost of fuel to be used in FAC; and 3) explain and support the Company's requests for certain new deferral authority and cost recovery of certain expense items.

Q. WHICH RATE BASE *PRO FORMA* ADJUSTMENTS WILL YOU BE SPONSORING?

A. The rate base adjustments for 2020 that I am sponsoring are attached as Petitioner's Exhibit 5-D (SES), Schedule RB-3 which is a supporting schedule to Company witness Ms. Diana L. Douglas' Petitioner's Exhibit 4-F (DLD), Schedule RB-1 and includes adjustments to:

- Remove SO_2 Native Load Purchase Costs from the Emission Allowance ("EA") Inventory
- Defer Native SO_2 EA Costs into a Regulatory Asset

Q. WHICH OPERATING INCOME *PRO FORMA* ADJUSTMENTS WILL YOU BE SPONSORING?

A. I am sponsoring the following *pro forma* adjustments applicable to the Test Period. These are attached to my testimony as Petitioner's Exhibit 5-A (SES) through 5-C (SES).

Exhibit	***Pro Forma* Adjustments**
Petitioner's Exhibit 5-A (SES)	Schedule REV4 – Remove Non-Native Sales Revenue Schedule REV5 – Remove Short-term Bundled Non-Native Sales Revenue Schedule REV6 – Remove Revenues for RECB/MVP Projects
Petitioner's Exhibit 5-B (SES)	Schedule COGS2 – Remove Fuel Expense Associated with Short-term Bundled Non-Native Sales Schedule COGS3 – Remove Fuel Expense Associated with Non-Native Sales Schedule COGS4 – Remove Retail Native SO2 Expenses Associated with Inventory Moved to Regulatory Asset
Petitioner's Exhibit 5-C (SES)	Schedule OM3 – Remove RECB/MVP O&M Expenses Schedule OM8 – Remove Indiana Electric Association ("IEA") O&M Expenses Schedule OM9 – Remove Brand Advertising O&M Expenses

Exhibit	***Pro Forma* Adjustments**
	Schedule OM10 – Remove Non-Jurisdictional Portion Henry County CT O&M Expenses Schedule OM11 – Remove Non-Utility Lighting O&M Expenses Schedule OM12 – Remove Premier Power O&M Expenses Schedule OM13 – Remove Electric Transportation Pilot Program O&M Expenses Schedule OM18 – Normalize Major Storm O&M Expenses Schedule OTX6 – Remove RECB/MVP Payroll Tax Expense Schedule OTX9 – Remove Non-Jurisdictional Portion Henry County CT Payroll Taxes Schedule OTX10 – Remove Non-Utility Lighting Payroll Taxes Schedule OTX11 – Remove Premier Power Payroll Taxes Schedule OTX12 – Remove Electric Transportation Pilot Program Payroll Taxes Schedule OTX14 – Normalize Major Storm Payroll Taxes

The Company's remaining operating income *pro forma* adjustments are sponsored by Duke Energy Indiana witnesses Ms. Douglas, Ms. Christa L. Graft, and Mr. Roger A. Flick II.

Q. WHICH EXISTING RATE ADJUSTMENT RIDERS WILL YOU ADDRESS IN YOUR TESTIMONY?

A. The rate adjustment riders that I will cover include the Company's:

- Standard Contract Rider No. 60 – Fuel Cost Adjustment ("FAC" or "Rider 60");
- Standard Contract Rider No. 68 – Midcontinent Independent System Operator "MISO" Management Costs and Revenue Adjustment ("Rider 68" or "RTO Rider");
- Standard Contract Rider No. 70 – Reliability Adjustment ("Rider 70" or "Reliability Rider"); and
- Standard Contract Rider No. 73 – Renewable Energy Project Revenue Adjustment ("Rider 73" or "Renewables Rider").

Copies of the red-lined and clean revised tariff sheets for the FAC, RTO, Rider 70 and Renewables Rider are attached to my testimony as Petitioner's Exhibit 5-G (SES) through 5-N (SES). These revised tariff sheets are also included with the complete set of base rate and other rider tariffs filed as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF).

Q. WHAT REQUESTS FOR NEW DEFERRAL AUTHORITY AND RATE RECOVERY WILL YOU ADDRESS IN YOUR TESTIMONY?

A. I support the Company's requests for new deferral authority and current or future recovery of certain expense items as follows:

- Creation of a storm normalization reserve account to be used for amounts over and under the amount of storm restoration costs included in base rates; and
- ~~Deferral of electric transportation pilot program expenses for recovery in future base rates; and~~
- Deferral as a regulatory asset of the native SO_2 inventory balance with recovery over the average remaining life of the Company's steam generating stations.

Q. ARE YOU SPONSORING ANY WORKPAPERS TO SUPPORT EXHIBITS?

A. I will be sponsoring workpapers for my attached exhibits. See Petitioner's Exhibit 5-O (SES) for a list of sponsored workpapers and the related exhibits.

II. RATE BASE *PRO FORMA* ADJUSTMENTS

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-F (DLD) SCHEDULE RB1 AND PETITIONER'S EXHIBIT 5-D (SES) SCHEDULE RB3.

A. Schedule RB1, sponsored by Ms. Douglas, summarizes the *pro forma* adjustments made to rate base. I am sponsoring Schedule RB3 which summarizes the adjustments to remove native SO_2 EA costs currently included in the EA inventory and to transfer these costs to a regulatory asset to be included in base rates for proposed recovery. Ms. Douglas is sponsoring Petitioner's Exhibit 4-F

(DLD) Schedules RB2, RB4 and RB5, which adjust the value of other rate base items.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-D (SES) SCHEDULE RB3 ASSOCIATED WITH THE NATIVE SO_2 EA INVENTORY.

A. Schedule RB3 details the *pro forma* adjustments made to remove the estimated costs of $9.8 million associated with native SO_2 EAs as of 12/31/2020 from the forecasted EA inventory balance and to establish a new regulatory asset of $9.5 million to recover those costs over a proposed twelve-year period, which represents the estimated average remaining life of the Company's steam generation stations (specifically Cayuga and Gibson stations) that gave rise to these EAs. With changing environmental rules, the Company believes it is unlikely that it will recover the native SO_2 EA costs over a reasonable period of time if the amounts are left in the inventory account.

Q. PLEASE EXPLAIN WHY THE AMOUNT FOR THE *PRO FORMA* ASSOCIATED WITH ESTABLISHING THE REGULATORY ASSET IS DIFFERENT THAN THE *PRO FORMA* AMOUNT BEING REMOVED FROM EA INVENTORY.

A. As shown on Schedule RB3 (lines 2-5), to determine the amount of the *pro forma* adjustment for the regulatory asset as of 12/31/2020, the Company started with the $9.8 million removed from the forecasted EA inventory balance at 12/31/2020 and then added back the forecasted consumption expense for the July 2020 through December 2020 period and subtracted the forecasted regulatory asset

amortization amounts for the same July 2020 through December 2020 period. This was done to reflect the Company's assumption that if this proposal is approved by the Commission and included in Step 1 of the rate update, as more fully described in the testimony of Ms. Douglas, then as of July 1, 2020, the native SO_2 consumption expense would be discontinued and the amortization of this newly established regulatory asset would begin. Therefore the 12/31/2020 balance of the regulatory asset would reflect the impact of these adjustments for the July 2020 through December 2020 period.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-E (SES) SCHEDULE RB3 ASSOCIATED WITH THE NATIVE SO_2 EA INVENTORY AS OF THE END OF 2019.

A. Petitioner's Exhibit 5-E (SES) Schedule RB3 reflects the amount that would be moved to a regulatory asset as of 12/31/2019 if that was the cut-off date for this proceeding. Ms. Douglas used this amount in her preparation of the Step 1 Rate Adjustment estimates.

III. OPERATING INCOME *PRO FORMA* ADJUSTMENTS

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE REV1.

A. Schedule REV1, sponsored by Ms. Douglas, summarizes the *pro forma* adjustments made to Revenues on Schedules REV2 through REV6. I am sponsoring Schedules REV4, REV5 and REV6 on Petitioner's Exhibit 5-A (SES).

Ms. Graft and Mr. Flick sponsor the remaining Schedules supporting the Revenue *pro forma* adjustments.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-A (SES) SCHEDULE REV4 - REMOVE REVENUES FOR NON-NATIVE SALES.

A. Schedule REV4 removes $34,717,000 from Test Period revenues associated with non-native sales to reflect that these revenues are included in the off-system sales sharing mechanism of Rider 70. The Company is proposing in this case to continue sharing non-native sales margins 50/50 with customers through the tracking mechanism. See discussion on this topic later in my testimony in Section V as well as the Direct Testimony of Company witness Mr. John A. Verderame.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-A (SES) SCHEDULE REV5 - REMOVE REVENUES ASSOCIATED WITH A SHORT-TERM BUNDLED NON-NATIVE CONTRACT.

A. Schedule REV5 removes $23,976,000 from Test Period revenues for a short-term bundled non-native contract. See discussion later in my testimony regarding proposal for changes to Rider 70 as well as the Direct Testimony of Company witness Mr. Verderame.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-A (SES) SCHEDULE REV6 - REMOVE REVENUES FOR RECB/MVP PROJECTS.

A. Schedule REV6 removes $3,369,000 from Test Period revenues associated with certain of the Company's transmission projects recovered via MISO. As discussed in more detail in the testimony of Ms. Douglas, the Company received

approval from MISO for certain Company-owned capital projects under MISO's Regional Expansion and Criteria and Benefits ("RECB") process and under MISO's Transmission Expansion Plan ("MTEP") as RECB projects or Multi-Value Projects ("MVP"). MISO reimburses the Company for the cost of these projects by charging all MISO transmission owners for the cost of the expansion projects through Schedule 26 and charging all market participants through Schedule 26A. As such, the Company excludes the revenues received and costs incurred associated with these projects from its retail ratemaking.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-B (SES).

A. Petitioner's Exhibit 5-B (SES) is a series of Schedules supporting the Cost of Goods Sold amounts included in the cost of service in this proceeding. Petitioner's Exhibit 5-B (SES) Schedule COGS1 summarizes the *pro forma* adjustments made to Cost of Goods Sold on Schedules COGS2 through COGS5. I sponsor and discuss Schedules COGS2 through COGS4 on Petitioner's Exhibit 5-B (SES). Company witness Ms. Graft sponsors Schedule COGS5.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-B (SES) SCHEDULE COGS2 – REMOVE FUEL EXPENSE ASSOCIATED WITH A SHORT-TERM BUNDLED NON-NATIVE CONTRACT.

A. Schedule COGS2 removes $11,234,000 from Test Period fuel expense (and the proposed base cost of fuel amount) to reflect the Company's proposal in this filing to include such expenses associated with short-term bundled non-native

contracts in Rider 70. This proposal is discussed later in Section V of my testimony, as well as the Direct Testimony of Company witness Mr. Verderame.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-B (SES) SCHEDULE COGS3 – REMOVE FUEL EXPENSE ASSOCIATED WITH NON-NATIVE SALES MARGIN.

A. Schedule COGS3 removes $32,217,000 from Test Period expenses to reflect that these expenses are included in the off-systems sales sharing mechanism of the Company's Rider 70.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-B (SES) SCHEDULE COGS4 - REMOVE RETAIL NATIVE SO_2 EXPENSES ASSOCIATED WITH INVENTORY MOVED TO REGULATORY ASSET.

A. Schedule COGS4 removes $213,000 from Test Period EA expense to reflect the Company's proposal (discussed earlier) that the retail portion of the native SO_2 EAs are moved from the EA inventory to a regulatory asset for recovery over the life of the Company's steam generating assets. The wholesale portion of the EA expense was left in the Test Period.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE OM2 AND PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE OTX1.

A. Schedule OM2, sponsored by Ms. Douglas, summarizes the *pro forma* adjustments made to O&M (excluding fuel, EAs and purchased power) on Schedules OM3 through OM20. Schedule OTX1, also sponsored by Ms. Douglas, summarizes the *pro forma* adjustments made to Other Taxes on

Schedules OTX2 through OTX14. I am sponsoring Schedules OM3, OM8, OM9, OM10, OM11, OM12, OM13, OM18, OTX6, OTX9, OTX10, OTX11, OTX12 and OTX14, which summarize some of the *pro forma* adjustments made to O&M and Other Taxes, on Petitioner's Exhibit 5-C (SES). Ms. Douglas and Ms. Graft sponsor the remaining Schedules supporting the O&M and Other Taxes *pro forma* adjustments.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM3 – REMOVE RECB/MVP RELATED COSTS.

A. Schedule OM3 is to remove $733,000 from Test Period O&M expenses for the Company's RECB and MVP projects, as discussed earlier with regards to the related revenues for these projects.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM8 – REMOVE EXPENSES FOR INDIANA ELECTRIC ASSOCIATION ("IEA").

A. Schedule OM8 is to remove $711,000 from test period expenses associated with the Company's membership in the IEA. Such adjustment is consistent with past practices in electric utility rate cases before this Commission.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM9 – REMOVE EXPENSES ASSOCIATED WITH BRAND ADVERTISING.

A. Schedule OM9 is to remove $414,000 from test period expenses related to costs incurred for image/brand advertising. Such adjustment is consistent with past practices in electric utility rate cases before this Commission.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM10 – REMOVE O&M EXPENSES ASSOCIATED WITH THE NON-JURISDICTIONAL PORTION OF HENRY COUNTY COMBUSTION TURBINE ("CT").

A. Schedule OM10 is to remove $1,015,000 from test period O&M expenses associated with the non-jurisdictional portion of the Company's Henry County Generating Station ("Henry County"). As discussed in detail in the testimony of Ms. Douglas, the Commission previously ordered in Cause No. 42145 that for retail ratemaking purposes the Company should separate out and exclude costs and revenues associated with 50 MWs of capacity at Henry County, which had previously been committed to a non-jurisdictional sale to Wabash Valley Power Association ("WVPA"). Ms. Douglas sponsors the *pro forma* adjustment to remove rate base associated with the non-jurisdictional portion. Workpaper OM1-SES details the calculation of the O&M adjustment and shows the derivation of the 36.56% used within the calculation.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM11 – REMOVE NON-UTILITY LIGHTING EXPENSES.

A. Schedule OM11 is to remove $3,622,000 from Test Period O&M expenses associated with non-utility lighting programs to ensure these expenses were not

included in the cost of service to all customers. The Company is being reimbursed for the O&M costs for this lighting by specific customers under the terms of customer-specific Outdoor Lighting Equipment Service ("OLES") agreements.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM12 – REMOVE PREMIER POWER EXPENSES.

A. Schedule OM12 is to remove $632,000 from Test Period O&M expenses to ensure these expenses were not included in the cost of service to all customers as the expenses for this program are considered non-utility.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM13 – REMOVE ELECTRIC TRANSPORTATION PILOT PROGRAM EXPENSES.

A. Schedule OM13 is to remove $333,000 from Test Period operating expenses for O&M costs associated with the Electric Transportation Pilot Program. Per the Commission's Docket Entry on December 5, 2019, consideration of this program has been removed from the general rate proceeding and will be addressed in a subdocket proceeding. ~~As discussed later in my testimony, the Company is requesting authority to defer O&M costs associated with the Electric Transportation Pilot Program, with carrying costs, for recovery in a future base rate case.~~

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM18 – NORMALIZE MAJOR STORM EXPENSES.

A. As discussed in more detail later in Section VI of my testimony, the Company is requesting to build into base rates a normalized level of major storm expenses based on a five-year historical average. Schedule OM18 increases the Test Period operating expenses by $2,454,000 to reflect this normalized level of major storm expenses.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX6 – REMOVE OTHER TAX EXPENSE FOR RECB/MVP PROJECTS.

A. Schedule OTX6 is to remove $21,000 from Test Period payroll taxes for the Company's RECB and MVP projects, as discussed earlier with regards to the related revenues and O&M expenses for these projects.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX9 – REMOVE OTHER TAX EXPENSE FOR THE NON-JURISDICTIONAL PORTION OF HENRY COUNTY CT.

A. Schedule OTX9 removes $32,000 of payroll taxes from the Test Period for the non-jurisdictional portion of Henry County CT, as discussed earlier with regards to the related O&M expenses.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX10 – REMOVE OTHER TAX EXPENSE FOR NON-UTILITY LIGHTING PROGRAMS.

A. Schedule OTX10 removes $112,000 from Test Period payroll taxes associated with non-utility lighting programs, where the Company's cost recovery is pursuant to the customer-specific OLES agreements.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX11 – REMOVE OTHER TAX EXPENSE FOR PREMIER POWER PROGRAM.

A. Schedule OTX11 removes $17,000 from Test Period payroll taxes associated with the Premier Power Program, which is a non-utility program as previously discussed.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX12 – REMOVE OTHER TAX EXPENSE FOR ELECTRIC TRANSPORTATION PILOT PROGRAM.

A. Schedule OTX12 removes $5,000 from Test Period payroll tax expenses associated with the Electric Transportation Pilot Program. Per the Commission's Docket Entry on December 5, 2019, consideration of this program has been removed from the general rate proceeding and will be addressed in a subdocket proceeding. ~~As discussed later in my testimony, the Company is requesting authority to defer payroll tax expenses associated with this Electric Transportation Pilot Program, with carrying costs, for recovery in a future base rate case.~~

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX14 – REMOVE OTHER TAX EXPENSE FOR MAJOR STORM NORMALIZATION.

A. Schedule OTX14 increases Test Period payroll taxes by $221,000 to reflect a normalized level of major storm expenses. As discussed in more detail later in

Section VI of my testimony, the Company is requesting to build into base rates a normalized level of major storm expenses based on a five-year historical average.

IV. BASE COST OF FUEL

Q. PLEASE EXPLAIN THE DOCUMENT THAT HAS BEEN MARKED FOR PURPOSES OF IDENTIFICATION AS PETITIONER'S EXHIBIT 5-F (SES) SCHEDULE COGS6.

A. Schedule COGS6 shows the derivation of the proposed base cost of fuel to be included in Petitioner's schedules of rates and charges. This exhibit reflects the Company's forecasted dispatch of system resources for 2020. Company witness Mr. Christopher M. Jacobi explains the development of the forecasted fuel and purchased power expenses and Company witnesses Mr. Verderame and Mr. Brett J. Phipps discusses the production cost model used to simulate generation output and associated costs used in developing that forecast. As shown in Exhibit 5-F (SES), the proposed base cost of fuel is 26.955 mills per kWh. By comparison, the Company's current base cost of fuel, which was established in Cause No. 42359 approved by the Commission on May 18, 2004, is 14.484 mills per kWh.

V. RATE ADJUSTMENT RIDERS

A. FAC Rider

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS FAC RIDER?

A. The Company is proposing the following changes to the FAC Rider:

- Add fuel-related PJM Interconnection LLC ("PJM") charges and credits on a

prospective basis to the native fuel cost recovered through the FAC;

- Discontinue the benchmark application to purchased power costs eligible to be recovered through the FAC;
- Implement changes to the calculation of the native/non-native sales stacking logic for long-term commitment generating units;
- Update the base cost of fuel amount; and
- Make administrative updates to the tariff page for consistency across riders and to reflect specific requests being made in this proceeding.

Q. PLEASE DISCUSS WHAT THE COMPANY IS PROPOSING FOR FUEL-RELATED PJM CHARGES AND CREDITS.

A. The Company's Madison Generating Station ("Madison") is considered an Indiana resource for MISO purposes, but is not physically located within the MISO footprint; instead it is connected to the PJM transmission grid. As discussed in more detail in the testimony of Mr. Verderame, energy from the station is transferred to MISO using firm transmission service and from an energy perspective it appears the same as other generating units within MISO. In addition to the settlement statements the Company receives from MISO, it also receives settlement statements from PJM, which includes additional charges and credits associated with Madison. Fuel-related charges and credits from MISO have been included in the Company's FAC filings since it began participating in the MISO energy market in 2005. The Company did not begin receiving the PJM settlement statements for Madison until 2012. To date, Duke Energy Indiana has

paid or received all the charges and credits associated with Madison and not passed any of the amounts onto the Company's retail customers.

The PJM charges and credits for Madison vary month-to-month. In some months the net amount on the settlement statement is a charge and in other months it's a credit. The total net of the charges and credits for 2012 through 2018 time period is a net credit (payment from PJM) of approximately $1.6 million. Madison station, similar to Duke Energy Indiana's other generating stations, is operated for the benefit of the Duke Energy Indiana customers regardless of its location with the PJM footprint; therefore, the Company believes it is appropriate to include the comparable fuel-related PJM charges and credits, in addition to the MISO fuel-related charges and credits, in the FAC rider on a prospective basis.

Q. PLEASE EXPLAIN WHAT THE COMPANY IS PROPOSING RELATED TO THE PURCHASED POWER BENCHMARK.

A. The Company is currently subject to a purchased power benchmark established by the Commission's August 18, 1999 Order in Cause No. 41363 and the guidance of the Commission in Cause Nos. 38706 FAC45, 38708 FAC45, 38707 FAC56 and 38707 FAC59. The benchmark is not intended to be a cap on recovery but instead has been used to identify when additional review may be needed to ensure the Company's cost of purchased power is reasonable. In his testimony Mr. Verderame discusses how the benchmark is calculated and what requirements must be met in order to recover any purchased power costs above the benchmark

in the Company's FAC rider. He further explains that with the operation of the MISO market, the risks that the benchmark was intended to address have been heavily mitigated. The Company is requesting that the purchased power benchmark procedures currently in place for Duke Energy Indiana be permanently waived by the Commission. Even absent the benchmark, the Company's purchased power costs would continue to remain subject to review and approval in each of the Company's FAC rider filings.

Q. PLEASE EXPLAIN WHAT THE COMPANY IS PROPOSING RELATED TO THE CALCULATION METHODOLOGY USED TO DETERMINE THE NATIVE/NON-NATIVE STACKING OF THE COMPANY'S GENERATION.

A. Today the Company determines what fuel costs are allocated to native customers (included in the FAC Rider) versus non-native customers (included in the Reliability Rider) using a production costing model. At a high-level, the model stacks based on average production costs ranked lowest to highest, with native customers generally being assigned the lowest cost resources. The Company is proposing to change the stacking logic from the current "average production cost" basis to an "incremental production cost basis" for long-term commitment generating units such as coal-fired and combined-cycle natural gas units. Duke Energy Indiana would continue to allocate costs for short-term commitment units, such as combustion turbines, on the existing average production cost basis.

If native fuel costs increase as a result of this change, the additional costs

would increase the fuel costs flowing through the FAC rider. Similarly, any decreases to native fuel costs would lower the fuel costs included in the FAC Rider. Changes to non-native fuel costs will be reflected in the Company's non-native sharing mechanism included in the Reliability Rider.

The Company believes this request is reasonable as the incremental cost approach will better align with MISO's actual dispatch logic and will more equitably and appropriately allocate fuel costs between native and non-native customers.

Please refer to Company witness Mr. Verderame's testimony for a more in-depth discussion of the Company's stacking process and the proposed changes to the calculation methodology.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT FAC RIDER TARIFF?

A. As discussed earlier in my testimony, the Company is proposing to update the base cost of fuel used to calculate the FAC Rider rate. The new proposed base cost of fuel is 26.955 mills per kWh, as compared to the current factor of 14.484 mills per kWh.

The Company is proposing some minor cosmetic and format changes to get more consistency across its various rider and rate tariffs and resetting the tariff numbering. Also, the Company is proposing to remove the gross-up factor currently reflected in the FAC, assuming the Commission approves the proposal discussed in Ms. Graft's testimony to add Utility Receipts Tax ("URT") directly

to the customers' bills rather than including in each rider factor.[1]

Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the FAC Rider are attached to my testimony as Petitioner's Exhibit 5-G (SES) and 5-H (SES). They are also included with the complete set of base rate and other rider tariffs that are filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). The complete rider with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

B. Regional Transmission Operator ("RTO") Rider

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS RTO RIDER?

A. The Company is proposing the following changes to the RTO Rider:

- Add non-fuel related PJM charges and credits on a prospective basis to the comparable MISO amounts currently included in the rider;
- Update the proposed annual base amounts for RTO non-fuel costs and RTO transmission revenues used in the rider calculation;
- Modify the factor calculation for HLF customers to be billed on KW demand rather than on kWh sales; and
- Make administrative updates to the tariff page for consistency across riders and to reflect specific requests being made in this proceeding.

[1] The Direct Testimony of Company witness Ms. Graft will explain the Company's proposal to include URT on customer bills in lieu of including it as a cost of service item and will support the *pro forma* adjustment to remove URT from the cost of service.

Q. WHAT IS THE COMPANY PROPOSING FOR NON-FUEL RELATED PJM CHARGES AND CREDITS?

A. As discussed in more detail above for the FAC Rider, the Company is currently receiving settlement statements from both PJM (for Madison) and MISO, but is only including the charges and credits from the MISO statements in its base rates and/or applicable rider rates to retail customers. The Company is proposing in this proceeding to include all RTO non-fuel charges and credits and transmission revenues (both from PJM and MISO) on a prospective basis in its RTO rider filings. The Company believes this request is reasonable as Madison is operated for the benefit of the Duke Energy Indiana customers.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT RTO RIDER TARIFF?

A. The Company is proposing to update the RTO non-fuel and transmission revenues amounts built into base rates and track the actual amounts experienced for these items above and below the amounts in base rates. In accordance with the Company's proposal, the new base amounts reflect both PJM and MISO charges and credits.

The Company is also proposing to update the calculation of the RTO Rider factor for HLF customers to bill on KW demand rather than kWh sales. This proposed methodology is consistent with how the HLF factors are currently calculated for the Company's Environmental and Renewables Riders.

The Company is proposing some minor cosmetic and format changes to

get more consistency across its various rider and rate tariffs and resetting the tariff numbering, including modifying the name of this rider from MISO to RTO to reflect the inclusion of applicable amounts from both MISO and PJM. In addition, the Company is proposing to update the revenue conversion factors to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding and remove the provision for utility receipts tax.

Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the RTO Rider are attached to my testimony as Petitioner's Exhibit 5-I (SES) and 5-J (SES). They are also included with the complete set of base rate and other rider tariffs that are filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). The complete rider with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

C. Reliability Rider

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS RELIABILITY RIDER?

A. The Company is proposing the following changes to the Reliability Rider (Rider 70):

- Retaining the non-native margin sharing mechanism but resetting the base amount to zero. The Company proposes to continue sharing 50/50 between customers and shareholders non-native margins realized during the reporting period for the rider, including both positive and potentially negative margins;

- Implementing a new sharing mechanism (or modify the existing non-native mechanism) to share 50/50 between customers and shareholders in margins realized on short-term bundled non-native sales.
- Implement changes to the calculation of the native/non-native sales stacking logic for long-term commitment generating units;
- Modify the capacity portion of the rider to allow for any differential in capacity costs and/or revenues related to Madison station;
- Update the proposed annual base amount for Power Share® bill credits;
- Modify the factor calculation for HLF customers to be billed on KW demand rather than on kWh sales; and
- Make administrative updates to the tariff page for consistency across riders and to reflect specific requests being made in this proceeding.

Q. WHAT CHANGE IS THE COMPANY PROPOSING TO THE CURRENT NON-NATIVE SHARING MECHANISM WITHIN THIS RIDER?

A. The Company is proposing to retain this mechanism but reset the base amount to zero. Non-native margins, both above and below zero, would be shared equally between the Company and customers with no specific amount embedded in base rates. As described in more detail in the testimony of Company witness Mr. Verderame, this proposal is reasonable as the Company has experienced significant variability in actual non-native margins realized since the Rider was implemented in the last base rate case. Given this variability, the Company believes that accounting for this item through a tracking mechanism is more

appropriate than building an amount into base rates.

Q. CAN YOU PLEASE DESCRIBE WHAT THE COMPANY IS REFERRING TO AS SHORT-TERM BUNDLED NON-NATIVE SALES?

A. Yes. The Company is using this term to describe a newer type of non-native contract that combines sales of both capacity and energy and is short-term in nature (five years or less). The negotiated contract prices will cover the energy costs and will make a contribution to fixed costs. The Company believes that these short-term bundled non-native agreements can be structured to meet a changing wholesale customer need and can be priced to compete at current market prices. For a more detailed discussion on this topic, please refer to the testimony of Company witness Mr. Verderame.

Q. PLEASE EXPLAIN HOW THE COMPANY IS CURRENTLY ACCOUNTING FOR THE ONE EXISTING SHORT-TERM BUNDLED NON-NATIVE CONTRACT.

A. The Company currently has one short-term bundled non-native contract expiring in 2021. As the contract terms for traditional native wholesale contracts have come to an end, some have not been renewed due to the current low-cost energy and capacity pricing available in MISO. This one short-term bundled non-native contract was priced to be competitive within the MISO market. The pricing for this contract is below the Company's fully embedded costs, but above the variable costs, such that it results in an overall net contribution to the Company's fixed costs. Absent this contribution, the retail customers would bear these costs

coming out of a retail base rate case where a new cost of service study is completed. Between retail rate cases, the Company has not updated its cost of service study and therefore no ratemaking impacts have been recognized to date for customers as a result of this one particular contract.

Q. WHAT IS THE COMPANY PROPOSING IN THIS PROCEEDING FOR THE CURRENT (AND ANY FUTURE) SHORT-TERM BUNDLED NON-NATIVE SALES?

A. The Company is proposing to include the margin from the one existing short-term bundled non-native sale, and any similar sales made in the future, within the Reliability Rider to be shared equally (50/50) between the Company and customers. This proposal provides a way for retail customers to realize a benefit as a result of the contribution to fixed costs made from these sales on a prospective basis.

Q. WHAT CHANGES ARE BEING PROPOSED TO THE NATIVE/NON-NATIVE COST ALLOCATIONS?

A. As discussed in more detail above for the FAC Rider, and in the testimony of Company witness Mr. Verderame, the Company is proposing to change the stacking logic in its production costing model from the current "average production cost" basis to an "incremental production cost" basis for long-term commitment generating units (*i.e.*, coal-fired and combined-cycle natural gas units). This production costing model is used to determine native versus non-native fuel costs. Any changes to native fuel costs resulting from a change in the

stacking logic would be reflected in the FAC Rider and any impacts to non-native fuel costs would flow through the non-native sharing mechanism in the Reliability Rider. The Company believes this proposal is reasonable as it more closely aligns with MISO's dispatch logic and will result in a more equitable allocation of fuel costs between native and non-native customers.

Q. WHAT CHANGES ARE BEING PROPOSED TO THE RIDER WITH REGARDS TO CAPACITY COSTS AND/OR REVENUES?

A. As more fully described in the testimony of Mr. Verderame, there have been changes recently to the MISO Resource Adequacy Construct that impact Duke Energy Indiana's use of Madison as a capacity resource. MISO has made a change, effective June 1, 2019 for the 2019/2020 Delivery Year, in how it will value capacity resources located outside the MISO footprint. This change has impacted the Company's Madison station, which is now being considered a PJM external zone resource and could therefore clear the annual MISO capacity auction at a different price than the Company's other generating assets. There was no price difference experienced during the 2019/2020 auction; however, price separation could occur in future auctions. To address situations like Madison and other similarly situated generation units, MISO created a hedge instrument called Historical Unit Consideration ("HUC") that are allocated to generators like Madison and are intended to fund the differential. Given these recent changes, the Company is proposing that in prospective Reliability Rider filings no capacity revenues would flow through the rider until the native load charges have been

met. If capacity costs have been offset, further revenues from capacity sales and HUC payments could be allocated as non-native sales margin and shared equally through the rider. If capacity costs for native load exceed all capacity revenues, the differential will be recovered in the same way it is today.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT TARIFF FOR THE RELIABILITY RIDER?

A. Yes. The Company is proposing to update the annual base amount for bill credits under the Power Share® program.

The Company is also proposing to update the calculation of the Reliability Rider factor for HLF customers to bill on KW demand rather than kWh sales. This proposed methodology is consistent with how the HLF factors are currently calculated for the Company's Environmental and Renewables Riders and with what is proposed for the RTO Rider.

The Company is also proposing some minor cosmetic and format changes to get more consistency across its various rider and rate tariffs and resetting the tariff numbering. Further, the Company is proposing to update the revenue conversion factors to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding and remove the provision for utility receipts tax.

Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the Reliability Rider are attached to my testimony as Petitioner's Exhibit 5-K (SES) and 5-L (SES). They are also

included with the complete set of base rate and other rider tariffs that are filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). The complete rider with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

D. Renewables Rider

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS RENEWABLES RIDER?

A. The Company is proposing to roll the net book value (original cost investment less accumulated depreciation) of all in-service renewables plant as of the end of the Test Period into base rates. Additionally, the Test Period level of O&M will be included in base rates, as will the depreciation associated with the investment rolled into rate base.

At the time of implementation of the new base rates resulting from this proceeding, the Renewables Rider will be revised to:

- remove the investment and O&M amounts included in base rates;
- recalculate the depreciation on the remaining investment (if any) using the new depreciation rates approved in this proceeding;
- change the 10.5% ROE used in the cost of capital calculation to the new ROE approved in this proceeding;
- update the calculation to begin reconciling return, in addition to the current practice of reconciling operating expenses; and,
- change the allocations to rate classes used in the calculation of rates to

use the final 4CP production demand allocators from this proceeding instead of the revenue requirements from Cause No. 42359; and

- make administrative updates to the tariff page for consistency across riders and to reflect specific requests being made in this proceeding.

This proposed treatment and changes are in accordance with the terms of the Settlement Agreements approved in Cause Nos. 44734 and 44767 approving rate recoveries for Crane Solar and Markland Uprate projects, respectively.

Q. UNDER THE COMPANY'S PROPOSAL, ARE THERE ANY OTHER ITEMS INCLUDED IN THE RENEWABLES RIDER THAT WILL NOT BE BUILT INTO BASE RATES?

A. Yes. The Company is proposing that post-in-service carrying costs and any credits from the sale of RECs not be included in base rates, but rather continue to be tracked in the Renewables Rider. The post-in-service carrying costs and REC sales are non-recurring and variable in nature, so these items would be best managed through the tracker, until such time as the Renewable Rider is no longer warranted.

In addition, once the Company is able to utilize the investment tax credits ("ITC") for the applicable renewable projects on its corporate consolidated federal income tax return, an additional credit for the retail jurisdictional portion of the associated ITC amortization would be included in the Renewable Rider. These credits have not been included in the proposed base rates in this proceeding to ensure compliance with the federal income tax normalization requirements

because the Company will not be able to utilize the credits until after the Test Period, as discussed in the Direct testimonies of Company witnesses Ms. Douglas and Mr. John R. Panizza.

Q. ARE THE COMPANY'S RATEMAKING PROPOSALS REGARDING RENEWABLES INVESTMENT AND COSTS CURRENTLY INCLUDED IN THE RENEWABLES RIDER REASONABLE?

A. Yes. The Company's proposal is consistent with past practice in Indiana to subsequently include in base rates in-service plant receiving CWIP ratemaking treatment via a tracker. The Company's proposed treatment is also in accordance with the terms of the Crane Solar and Markland Uprate Settlement Agreements. To continue to track the post-in-service carrying costs and any REC sale net proceeds in the Renewables Rider, along with any incremental new investment and related depreciation and O&M, is a reasonable way to recover the non-routine and variable Renewables Rider costs.

Q. HOW WILL THE COMPANY IMPLEMENT THE CHANGES TO THE RENEWABLES RIDER ONCE NEW BASE RATES ARE APPROVED?

A. The Company will file revised rate schedules resetting the then-current rates to remove the amounts included in base rates and adjust the ROE, revenue conversion factors, and allocation factors. This will be done concurrently with filing the new base rate tariffs, with both base rates and rider rate changes to be implemented on a service-rendered basis.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT

RENEWABLES RIDER TARIFF?

A. Yes. The Company is proposing some minor cosmetic and format changes to get more consistency across its various rider and rate tariffs and resetting the tariff numbering. In addition, the Company is proposing reconciliation of the return component of the Renewable Rider in addition to the operating costs portion, consistent with its proposal for Rider 62, and is updating its language to reflect that change. Further, the Company is proposing to update the revenue conversion factors to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding and remove the provision for utility receipts tax.

Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the Renewables Rider are attached to my testimony as Petitioner's Exhibit 5-M (SES) and 5-N (SES). They are also included with the complete set of base rate and other rider tariffs that are filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). The complete rider with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

VI. DEFERRAL AND COST RECOVERY REQUESTS

A. Storm Normalization Reserve

Q. WHAT IS THE COMPANY PROPOSING RELATED TO MAJOR STORM EXPENSES?

A. The Company is seeking approval of its request to build into retail base rates a

normalized level of major storm expenses of approximately $12.7 million based on a five-year historical average of such costs for calendar years 2013 through 2018. A *pro forma* adjustment was made to increase the Test Period amount for storms from $10.0 million to the $12.7 million level. In addition to establishing a normalized level in base rates, the Company is proposing to establish a Major Storm Damage Restoration Reserve ("Major Storm Reserve") to track differences between the operating costs incurred and the amount collected in base rates. Any under-recovery would be recorded to a Regulatory Asset and any over-recovery would be recorded as a Regulatory Liability. The net amount for the Major Storm Reserve would be addressed for recovery in the next retail base rate case.

Q. FOR PURPOSES OF THIS PROPOSAL, HOW IS THE COMPANY DEFINING A MAJOR STORM?

A. Company witness Ms. Cicely M. Hart provides information in her testimony on this subject. Ms. Hart's testimony includes a table showing Duke Energy Indiana's historical 2013 through 2018 transmission and distribution costs incurred for major storms based on Major Event Days. Generally speaking, a storm is classified as a Major Event Day when a major reliability event causes a utility to shift into a crisis mode of operation in order to adequately respond. As further described in Ms. Hart's testimony, the Institute of Electrical and Electronic Engineers ("IEEE") 1366 statistically defines a major event day as a day in which the daily system Average Interruption Duration Index ("SAIDI") exceeds a threshold value (calculated from a 5-year average daily SAIDI). See

Workpaper OM3-SES for the supporting calculation for five-year historical average for major storm costs that was used to determine the normalized level.

Q. HOW DOES THE COMPANY PLAN TO ADDRESS ANY UNDER- OR OVER-RECOVERY IN THE MAJOR STORM RESERVE IN THE NEXT BASE RATE CASE?

A. In its next retail base rate case, Duke Energy Indiana proposes to include an amortization in the cost of service to either reduce the cost of service for any over-recovery or increase the cost of service for any under-recovery in the Major Storm Reserve at the end of the historical base period.

Q. WHY DOES THE COMPANY BELIEVE IT IS APPROPRIATE TO ESTABLISH A MAJOR STORM RESERVE?

A. As evidenced by the historical cost information shown in Ms. Hart's testimony, the costs for Major Storms vary significantly year-to-year based on the actual number of Major Event Days declared and the types of restoration efforts required. During the 2013 to 2018 historical period alone, costs varied from a low of $6.5 million in one year to a high of $21.4 million in another year. Although the Company is proposing to normalize Major Storm costs for establishing base rates, the timing, frequency, and costs for such Major Storms are unpredictable and therefore challenging for the Company to establish a precise amount in base rates to cover its prudently incurred costs (nothing more or nothing less). The Company believes its proposal to establish a Major Storm Reserve is reasonable and balances the interests of both the Company and its customers by smoothing

out these costs and providing for the Company to be able to recover no more or less than its actual costs.

~~**B. Electric Transportation Pilot Expenses**~~

~~**Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S ELECTRIC TRANSPORTATION PILOT PROGRAM.**~~

~~A. As discussed in detail in the testimony of Duke Energy Indiana witness Mr. Lang W. Reynolds, the Company is requesting authorization for an Electric Transportation Pilot Program ("Pilot Program") that will allow Duke Energy Indiana to deploy electric vehicle ("EV") infrastructure to meet growing market needs. Duke Energy Indiana's proposal consists of five (5) distinct programs, which are designed to accomplish the following overall goals:~~

- ~~Deploy a foundational level of fast charging infrastructure in Indiana;~~
- ~~Research the effects of increasing adoption of different types of electric vehicles on the electric system;~~
- ~~Research customer EV charging behavior; and~~
- ~~Determine the potential financial and environmental benefits for Indiana.~~

~~**Q. WHAT IS THE FORECASTED COST OF THE ELECTRIC TRANSPORTATION PILOT PROGRAM?**~~

~~A. The total forecasted cost of the Pilot Program is approximately $15.3 million over the 2019 through 2023 time period, which is comprised of approximately $11.4 million of capital spend and approximately $3.9 of O&M spend. Although the~~

~~actual costs will likely vary somewhat from the forecast, the Company's proposal is to cap cost recovery at $15.3 million excluding the proposed carrying costs discussed below.~~

~~**Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE CAPITAL COSTS FOR THE PILOT PROGRAM?**~~

~~A. Capital components for this program that are in-service as of the end of the Test Period will be included in the base rates proposed in this proceeding. For capital components that are not in-service as of the end of the Test Period, the Company is proposing to defer depreciation expense and post-in-service carrying costs at the weighted average cost of capital rate as regulatory assets until these capital components are deemed to be used and useful in a future base rate case.~~

~~**Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE O&M COSTS FOR THE EV PILOT PROGRAM?**~~

~~A. The Company is proposing to defer O&M costs incurred from 2019 through 2023 for the Pilot Program, with carrying costs at the weighted average cost of capital rate, as a regulatory asset to be held for recovery in a future base rate case. As discussed earlier in my testimony, a *pro forma* adjustment was made to remove the forecasted 2020 O&M costs from the Company's Test Period, such that a level has not been built into base rates for these costs. The total amount of O&M to be deferred for the life of the pilot program, excluding carrying costs, is currently estimated to be approximately $3.9 million.~~

~~**Q. IS THE COMPANY'S RATEMAKING PROPOSAL REASONABLE?**~~

~~A. Yes. The proposed Electric Transportation Pilot Program provides many potential benefits to customers, as described fully in the testimony of Mr. Reynolds, and it is reasonable and prudent to allow the Company to recover the associated costs.~~

B~~C~~. Regulatory Asset Request for Native SO_2 EA Recovery

Q. WHAT SPECIFICALLY IS THE COMPANY REQUESTING?

A. As discussed earlier in my testimony, the Company is proposing to transfer the native SO_2 EAs from the EA inventory account to a new Regulatory Asset account. The new Regulatory Asset would be amortized over a proposed twelve-year period, which represents the estimated average remaining life of the Company's steam generation stations (specifically Cayuga and Gibson stations). Assuming the Commission approves this request, at the time new rates go into effect, the native SO_2 EA consumption expense would decrease to zero and the Company would begin recognizing the regulatory asset amortization expense.

Q. WHY IS THE COMPANY REQUESTING THIS NEW REGULATORY ASSET?

A. With changing environmental rules, the Company believes it is unlikely that it will recover the native SO_2 EA costs over a reasonable period of time if the amounts are left in the inventory account. Based on the forecasted native SO_2 consumption expense for 2020, if the Company received no additional allotments of zero cost SO_2 EAs from the EPA after 2020, it will take over 43 years to utilize the forecasted EA inventory balance at the end of 2020. Adding these zero-cost

EAs to the inventory at the beginning of each year will continue to lower the associated weighted average cost of inventory that is then used to calculate the associated native consumption expense currently recovered through the Company's Standard Contract Rider No. 63 – SO_2, NOx and Hg Emission Allowance Adjustment. Absent special regulatory treatment, it is unlikely that the Company will ever fully recover these costs.

Q. IS THE COMPANY'S PROPOSAL REASONABLE?

A. Yes, the costs for the native SO_2 EAs were prudently incurred on behalf of the Company's native customers. The Company's proposal to recover these costs over the estimated remaining lives of the generating assets driving these costs is reasonable.

CD. Requested Accounting Treatment

Q. IS THE ACCOUNTING TREATMENT PROPOSED BY THE COMPANY ~~FOR POST-IN-SERVICE CARRYING COSTS, DEFERRED DEPRECIATION AND DEFERRED O&M~~ IN ACCORDANCE WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")?

A. Yes. GAAP specifically discusses the accounting for a regulator's actions designed to protect a utility from the effects of regulatory lag. Topic 980 of the Financial Accounting Standards Board's Accounting Standards Codification ("ASC") covers the accounting guidance for regulated operations formerly provided in Statement of Financial Accounting Standards No. 71. Costs associated with regulatory lag can be capitalized for accounting purposes,

provided the provisions of ASC 980-340-25-1 are met. The guidance states:

> Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met: (a) It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes and (b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost. A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

Q. DO YOU HAVE AN OPINION AS TO THE APPROPRIATENESS OF AND THE ACTION REQUIRED BY THE COMMISSION TO ALLOW FOR THE REQUESTED ACCOUNTING TREATMENT?

A. Yes. In my opinion, ~~deferral in a regulatory asset of the retail jurisdictional portion of the post-in-service carrying costs, depreciation, and O&M costs incurred for the benefit of customers until they can be included in retail base rates or rider rates~~ the accounting treatment requested by the Company is appropriate from a ratemaking perspective, and such treatment will minimize the timing differences between cost recognition on the Company's books and cost recovery. In order for the Company to defer the Major Storm Reserve~~, Electric Transportation Pilot Program~~ and native SO_2 EA costs as regulatory assets, it must be probable that such costs will be recovered through rates in future periods. In order to satisfy the probability standard, the Commission's Order in this

proceeding should specifically approve the accounting and ratemaking treatment proposed by Duke Energy Indiana.

VII. CONCLUSION

Q. WERE PETITIONER'S EXHIBITS 5-A (SES) THROUGH 5-O (SES) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

ATTACHMENT 1

PETITIONER'S EXHIBIT 5-C (SES)
Duke Energy Indiana 2019 Base Rate Case
Other Taxes
Schedule OTX12

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Allocated Payroll Tax Expense for Electric Vehicle Pilot Program

(Thousands of Dollars)

This pro forma adjustment is to remove allocated payroll taxes associated with the Electric Vehicle Pilot Program.
Amounts to be proposed for deferral in ~~this proceeding~~ the subdocket proceeding.

Line No.	Description	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Account 0408960 - Allocated Payroll Taxes [2/]	$ 5	$ -	$ (5)	1
2	Total	$ 5	$ -	$ (5)	2

[1/] To PETITIONER'S EXHIBIT 4-E (DLD).
[2/] See: MSFR Workpaper OM4-SES.

CORRECTED DIRECT TESTIMONY OF SUZANNE E. SIEFERMAN, DIRECTOR, RATES AND REGULATORY PLANNING ON BEHALF OF DUKE ENERGY INDIANA, LLC BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Suzanne E. Sieferman, and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company") as Director, Rates and Regulatory Planning. Duke Energy Indiana is a wholly owned, indirect subsidiary of Duke Energy Corporation.

Q. PLEASE DESCRIBE YOUR DUTIES AS DIRECTOR, RATES AND REGULATORY PLANNING.

A. I am responsible for the preparation of financial and accounting data used in Company rate filings and petitions for changes in fuel cost adjustment factors and other tracking mechanisms.

Q. PLEASE STATE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I am a graduate of Indiana University, holding a Bachelor of Science Degree in Business, with a major in Accounting. I am a Certified Public Accountant ("CPA") and a member of the Indiana CPA Society. Since my employment with the Company in 1990, I have held various financial and accounting positions supporting the Company and its affiliates. Prior to my move to the Rates and

Regulatory Planning department in 2008, I held positions in Benefits Accounting, Corporate Accounting, Business Unit Financial Reporting and External Reporting groups.

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

A. My testimony will: 1) address certain rate base and operating income *pro forma* adjustments applicable to the twelve months ended December 2020 forecasted test period ("Test Period"); 2) explain and support proposed changes to certain of the Company's existing rate adjustment riders to be effective with the implementation of the Company's revised base rates, including the determination of the base cost of fuel to be used in FAC; and 3) explain and support the Company's requests for certain new deferral authority and cost recovery of certain expense items.

Q. WHICH RATE BASE *PRO FORMA* ADJUSTMENTS WILL YOU BE SPONSORING?

A. The rate base adjustments for 2020 that I am sponsoring are attached as Petitioner's Exhibit 5-D (SES), Schedule RB-3 which is a supporting schedule to Company witness Ms. Diana L. Douglas' Petitioner's Exhibit 4-F (DLD), Schedule RB-1 and includes adjustments to:

- Remove SO_2 Native Load Purchase Costs from the Emission Allowance ("EA") Inventory
- Defer Native SO_2 EA Costs into a Regulatory Asset

Q. WHICH OPERATING INCOME *PRO FORMA* ADJUSTMENTS WILL YOU BE SPONSORING?

A. I am sponsoring the following *pro forma* adjustments applicable to the Test Period. These are attached to my testimony as Petitioner's Exhibit 5-A (SES) through 5-C (SES).

Exhibit	***Pro Forma* Adjustments**
Petitioner's Exhibit 5-A (SES)	Schedule REV4 – Remove Non-Native Sales Revenue Schedule REV5 – Remove Short-term Bundled Non-Native Sales Revenue Schedule REV6 – Remove Revenues for RECB/MVP Projects
Petitioner's Exhibit 5-B (SES)	Schedule COGS2 – Remove Fuel Expense Associated with Short-term Bundled Non-Native Sales Schedule COGS3 – Remove Fuel Expense Associated with Non-Native Sales Schedule COGS4 – Remove Retail Native SO2 Expenses Associated with Inventory Moved to Regulatory Asset
Petitioner's Exhibit 5-C (SES)	Schedule OM3 – Remove RECB/MVP O&M Expenses Schedule OM8 – Remove Indiana Electric Association ("IEA") O&M Expenses Schedule OM9 – Remove Brand Advertising O&M Expenses

Exhibit	***Pro Forma* Adjustments**
	Schedule OM10 – Remove Non-Jurisdictional Portion Henry County CT O&M Expenses Schedule OM11 – Remove Non-Utility Lighting O&M Expenses Schedule OM12 – Remove Premier Power O&M Expenses Schedule OM13 – Remove Electric Transportation Pilot Program O&M Expenses Schedule OM18 – Normalize Major Storm O&M Expenses Schedule OTX6 – Remove RECB/MVP Payroll Tax Expense Schedule OTX9 – Remove Non-Jurisdictional Portion Henry County CT Payroll Taxes Schedule OTX10 – Remove Non-Utility Lighting Payroll Taxes Schedule OTX11 – Remove Premier Power Payroll Taxes Schedule OTX12 – Remove Electric Transportation Pilot Program Payroll Taxes Schedule OTX14 – Normalize Major Storm Payroll Taxes

The Company's remaining operating income *pro forma* adjustments are sponsored by Duke Energy Indiana witnesses Ms. Douglas, Ms. Christa L. Graft, and Mr. Roger A. Flick II.

Q. WHICH EXISTING RATE ADJUSTMENT RIDERS WILL YOU ADDRESS IN YOUR TESTIMONY?

A. The rate adjustment riders that I will cover include the Company's:

- Standard Contract Rider No. 60 – Fuel Cost Adjustment ("FAC" or "Rider 60");
- Standard Contract Rider No. 68 – Midcontinent Independent System Operator "MISO" Management Costs and Revenue Adjustment ("Rider 68" or "RTO Rider");
- Standard Contract Rider No. 70 – Reliability Adjustment ("Rider 70" or "Reliability Rider"); and
- Standard Contract Rider No. 73 – Renewable Energy Project Revenue Adjustment ("Rider 73" or "Renewables Rider").

Copies of the red-lined and clean revised tariff sheets for the FAC, RTO, Rider 70 and Renewables Rider are attached to my testimony as Petitioner's Exhibit 5-G (SES) through 5-N (SES). These revised tariff sheets are also included with the complete set of base rate and other rider tariffs filed as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF).

Q. WHAT REQUESTS FOR NEW DEFERRAL AUTHORITY AND RATE RECOVERY WILL YOU ADDRESS IN YOUR TESTIMONY?

A. I support the Company's requests for new deferral authority and current or future recovery of certain expense items as follows:

- Creation of a storm normalization reserve account to be used for amounts over and under the amount of storm restoration costs included in base rates; and
- Deferral as a regulatory asset of the native SO_2 inventory balance with recovery over the average remaining life of the Company's steam generating stations.

Q. ARE YOU SPONSORING ANY WORKPAPERS TO SUPPORT EXHIBITS?

A. I will be sponsoring workpapers for my attached exhibits. See Petitioner's Exhibit 5-O (SES) for a list of sponsored workpapers and the related exhibits.

II. RATE BASE *PRO FORMA* ADJUSTMENTS

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-F (DLD) SCHEDULE RB1 AND PETITIONER'S EXHIBIT 5-D (SES) SCHEDULE RB3.

A. Schedule RB1, sponsored by Ms. Douglas, summarizes the *pro forma* adjustments made to rate base. I am sponsoring Schedule RB3 which summarizes the adjustments to remove native SO_2 EA costs currently included in the EA inventory and to transfer these costs to a regulatory asset to be included in base rates for proposed recovery. Ms. Douglas is sponsoring Petitioner's Exhibit 4-F (DLD) Schedules RB2, RB4 and RB5, which adjust the value of other rate base items.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-D (SES) SCHEDULE RB3 ASSOCIATED WITH THE NATIVE SO_2 EA INVENTORY.

A. Schedule RB3 details the *pro forma* adjustments made to remove the estimated costs of $9.8 million associated with native SO_2 EAs as of 12/31/2020 from the forecasted EA inventory balance and to establish a new regulatory asset of $9.5 million to recover those costs over a proposed twelve-year period, which represents the estimated average remaining life of the Company's steam generation stations (specifically Cayuga and Gibson stations) that gave rise to these EAs. With changing environmental rules, the Company believes it is unlikely that it will recover the native SO_2 EA costs over a reasonable period of time if the amounts are left in the inventory account.

Q. PLEASE EXPLAIN WHY THE AMOUNT FOR THE *PRO FORMA* ASSOCIATED WITH ESTABLISHING THE REGULATORY ASSET IS DIFFERENT THAN THE *PRO FORMA* AMOUNT BEING REMOVED FROM EA INVENTORY.

A. As shown on Schedule RB3 (lines 2-5), to determine the amount of the *pro forma* adjustment for the regulatory asset as of 12/31/2020, the Company started with the $9.8 million removed from the forecasted EA inventory balance at 12/31/2020 and then added back the forecasted consumption expense for the July 2020 through December 2020 period and subtracted the forecasted regulatory asset amortization amounts for the same July 2020 through December 2020 period. This was done to reflect the Company's assumption that if this proposal is

approved by the Commission and included in Step 1 of the rate update, as more fully described in the testimony of Ms. Douglas, then as of July 1, 2020, the native SO_2 consumption expense would be discontinued and the amortization of this newly established regulatory asset would begin. Therefore the 12/31/2020 balance of the regulatory asset would reflect the impact of these adjustments for the July 2020 through December 2020 period.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-E (SES) SCHEDULE RB3 ASSOCIATED WITH THE NATIVE SO_2 EA INVENTORY AS OF THE END OF 2019.

A. Petitioner's Exhibit 5-E (SES) Schedule RB3 reflects the amount that would be moved to a regulatory asset as of 12/31/2019 if that was the cut-off date for this proceeding. Ms. Douglas used this amount in her preparation of the Step 1 Rate Adjustment estimates.

III. OPERATING INCOME *PRO FORMA* ADJUSTMENTS

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE REV1.

A. Schedule REV1, sponsored by Ms. Douglas, summarizes the *pro forma* adjustments made to Revenues on Schedules REV2 through REV6. I am sponsoring Schedules REV4, REV5 and REV6 on Petitioner's Exhibit 5-A (SES). Ms. Graft and Mr. Flick sponsor the remaining Schedules supporting the Revenue *pro forma* adjustments.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-A (SES) SCHEDULE REV4 - REMOVE REVENUES FOR NON-NATIVE SALES.

A. Schedule REV4 removes $34,717,000 from Test Period revenues associated with non-native sales to reflect that these revenues are included in the off-system sales sharing mechanism of Rider 70. The Company is proposing in this case to continue sharing non-native sales margins 50/50 with customers through the tracking mechanism. See discussion on this topic later in my testimony in Section V as well as the Direct Testimony of Company witness Mr. John A. Verderame.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-A (SES) SCHEDULE REV5 - REMOVE REVENUES ASSOCIATED WITH A SHORT-TERM BUNDLED NON-NATIVE CONTRACT.

A. Schedule REV5 removes $23,976,000 from Test Period revenues for a short-term bundled non-native contract. See discussion later in my testimony regarding proposal for changes to Rider 70 as well as the Direct Testimony of Company witness Mr. Verderame.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-A (SES) SCHEDULE REV6 - REMOVE REVENUES FOR RECB/MVP PROJECTS.

A. Schedule REV6 removes $3,369,000 from Test Period revenues associated with certain of the Company's transmission projects recovered via MISO. As discussed in more detail in the testimony of Ms. Douglas, the Company received approval from MISO for certain Company-owned capital projects under MISO's Regional Expansion and Criteria and Benefits ("RECB") process and under

MISO's Transmission Expansion Plan ("MTEP") as RECB projects or Multi-Value Projects ("MVP"). MISO reimburses the Company for the cost of these projects by charging all MISO transmission owners for the cost of the expansion projects through Schedule 26 and charging all market participants through Schedule 26A. As such, the Company excludes the revenues received and costs incurred associated with these projects from its retail ratemaking.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-B (SES).

A. Petitioner's Exhibit 5-B (SES) is a series of Schedules supporting the Cost of Goods Sold amounts included in the cost of service in this proceeding. Petitioner's Exhibit 5-B (SES) Schedule COGS1 summarizes the *pro forma* adjustments made to Cost of Goods Sold on Schedules COGS2 through COGS5. I sponsor and discuss Schedules COGS2 through COGS4 on Petitioner's Exhibit 5-B (SES). Company witness Ms. Graft sponsors Schedule COGS5.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-B (SES) SCHEDULE COGS2 – REMOVE FUEL EXPENSE ASSOCIATED WITH A SHORT-TERM BUNDLED NON-NATIVE CONTRACT.

A. Schedule COGS2 removes $11,234,000 from Test Period fuel expense (and the proposed base cost of fuel amount) to reflect the Company's proposal in this filing to include such expenses associated with short-term bundled non-native contracts in Rider 70. This proposal is discussed later in Section V of my testimony, as well as the Direct Testimony of Company witness Mr. Verderame.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-B (SES) SCHEDULE COGS3 – REMOVE FUEL EXPENSE ASSOCIATED WITH NON-NATIVE SALES MARGIN.

A. Schedule COGS3 removes $32,217,000 from Test Period expenses to reflect that these expenses are included in the off-systems sales sharing mechanism of the Company's Rider 70.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-B (SES) SCHEDULE COGS4 - REMOVE RETAIL NATIVE SO_2 EXPENSES ASSOCIATED WITH INVENTORY MOVED TO REGULATORY ASSET.

A. Schedule COGS4 removes $213,000 from Test Period EA expense to reflect the Company's proposal (discussed earlier) that the retail portion of the native SO_2 EAs are moved from the EA inventory to a regulatory asset for recovery over the life of the Company's steam generating assets. The wholesale portion of the EA expense was left in the Test Period.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE OM2 AND PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE OTX1.

A. Schedule OM2, sponsored by Ms. Douglas, summarizes the *pro forma* adjustments made to O&M (excluding fuel, EAs and purchased power) on Schedules OM3 through OM20. Schedule OTX1, also sponsored by Ms. Douglas, summarizes the *pro forma* adjustments made to Other Taxes on Schedules OTX2 through OTX14. I am sponsoring Schedules OM3, OM8, OM9, OM10, OM11, OM12, OM13, OM18, OTX6, OTX9, OTX10, OTX11, OTX12

and OTX14, which summarize some of the *pro forma* adjustments made to O&M and Other Taxes, on Petitioner's Exhibit 5-C (SES). Ms. Douglas and Ms. Graft sponsor the remaining Schedules supporting the O&M and Other Taxes *pro forma* adjustments.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM3 – REMOVE RECB/MVP RELATED COSTS.

A. Schedule OM3 is to remove $733,000 from Test Period O&M expenses for the Company's RECB and MVP projects, as discussed earlier with regards to the related revenues for these projects.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM8 – REMOVE EXPENSES FOR INDIANA ELECTRIC ASSOCIATION ("IEA").

A. Schedule OM8 is to remove $711,000 from test period expenses associated with the Company's membership in the IEA. Such adjustment is consistent with past practices in electric utility rate cases before this Commission.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM9 – REMOVE EXPENSES ASSOCIATED WITH BRAND ADVERTISING.

A. Schedule OM9 is to remove $414,000 from test period expenses related to costs incurred for image/brand advertising. Such adjustment is consistent with past practices in electric utility rate cases before this Commission.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM10 – REMOVE O&M EXPENSES ASSOCIATED WITH THE NON-JURISDICTIONAL PORTION OF HENRY COUNTY COMBUSTION TURBINE ("CT").

A. Schedule OM10 is to remove $1,015,000 from test period O&M expenses associated with the non-jurisdictional portion of the Company's Henry County Generating Station ("Henry County"). As discussed in detail in the testimony of Ms. Douglas, the Commission previously ordered in Cause No. 42145 that for retail ratemaking purposes the Company should separate out and exclude costs and revenues associated with 50 MWs of capacity at Henry County, which had previously been committed to a non-jurisdictional sale to Wabash Valley Power Association ("WVPA"). Ms. Douglas sponsors the *pro forma* adjustment to remove rate base associated with the non-jurisdictional portion. Workpaper OM1-SES details the calculation of the O&M adjustment and shows the derivation of the 36.56% used within the calculation.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM11 – REMOVE NON-UTILITY LIGHTING EXPENSES.

A. Schedule OM11 is to remove $3,622,000 from Test Period O&M expenses associated with non-utility lighting programs to ensure these expenses were not included in the cost of service to all customers. The Company is being reimbursed for the O&M costs for this lighting by specific customers under the

terms of customer-specific Outdoor Lighting Equipment Service ("OLES") agreements.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM12 – REMOVE PREMIER POWER EXPENSES.

A. Schedule OM12 is to remove $632,000 from Test Period O&M expenses to ensure these expenses were not included in the cost of service to all customers as the expenses for this program are considered non-utility.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM13 – REMOVE ELECTRIC TRANSPORTATION PILOT PROGRAM EXPENSES.

A. Schedule OM13 is to remove $333,000 from Test Period operating expenses for O&M costs associated with the Electric Transportation Pilot Program. Per the Commission's Docket Entry on December 5, 2019, consideration of this program has been removed from the general rate proceeding and will be addressed in a subdocket proceeding.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM18 – NORMALIZE MAJOR STORM EXPENSES.

A. As discussed in more detail later in Section VI of my testimony, the Company is requesting to build into base rates a normalized level of major storm expenses based on a five-year historical average. Schedule OM18 increases the Test Period operating expenses by $2,454,000 to reflect this normalized level of major storm expenses.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX6 – REMOVE OTHER TAX EXPENSE FOR RECB/MVP PROJECTS.

A. Schedule OTX6 is to remove $21,000 from Test Period payroll taxes for the Company's RECB and MVP projects, as discussed earlier with regards to the related revenues and O&M expenses for these projects.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX9 – REMOVE OTHER TAX EXPENSE FOR THE NON-JURISDICTIONAL PORTION OF HENRY COUNTY CT.

A. Schedule OTX9 removes $32,000 of payroll taxes from the Test Period for the non-jurisdictional portion of Henry County CT, as discussed earlier with regards to the related O&M expenses.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX10 – REMOVE OTHER TAX EXPENSE FOR NON-UTILITY LIGHTING PROGRAMS.

A. Schedule OTX10 removes $112,000 from Test Period payroll taxes associated with non-utility lighting programs, where the Company's cost recovery is pursuant to the customer-specific OLES agreements.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX11 – REMOVE OTHER TAX EXPENSE FOR PREMIER POWER PROGRAM.

A. Schedule OTX11 removes $17,000 from Test Period payroll taxes associated with the Premier Power Program, which is a non-utility program as previously discussed.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX12 – REMOVE OTHER TAX EXPENSE FOR ELECTRIC TRANSPORTATION PILOT PROGRAM.

A. Schedule OTX12 removes $5,000 from Test Period payroll tax expenses associated with the Electric Transportation Pilot Program. Per the Commission's Docket Entry on December 5, 2019, consideration of this program has been removed from the general rate proceeding and will be addressed in a subdocket proceeding.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX14 – REMOVE OTHER TAX EXPENSE FOR MAJOR STORM NORMALIZATION.

A. Schedule OTX14 increases Test Period payroll taxes by $221,000 to reflect a normalized level of major storm expenses. As discussed in more detail later in Section VI of my testimony, the Company is requesting to build into base rates a normalized level of major storm expenses based on a five-year historical average.

IV. BASE COST OF FUEL

Q. PLEASE EXPLAIN THE DOCUMENT THAT HAS BEEN MARKED FOR PURPOSES OF IDENTIFICATION AS PETITIONER'S EXHIBIT 5-F (SES) SCHEDULE COGS6.

A. Schedule COGS6 shows the derivation of the proposed base cost of fuel to be included in Petitioner's schedules of rates and charges. This exhibit reflects the Company's forecasted dispatch of system resources for 2020. Company witness Mr. Christopher M. Jacobi explains the development of the forecasted fuel and purchased power expenses and Company witnesses Mr. Verderame and Mr. Brett J. Phipps discusses the production cost model used to simulate generation output and associated costs used in developing that forecast. As shown in Exhibit 5-F (SES), the proposed base cost of fuel is 26.955 mills per kWh. By comparison, the Company's current base cost of fuel, which was established in Cause No. 42359 approved by the Commission on May 18, 2004, is 14.484 mills per kWh.

V. RATE ADJUSTMENT RIDERS

A. FAC Rider

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS FAC RIDER?

A. The Company is proposing the following changes to the FAC Rider:

- Add fuel-related PJM Interconnection LLC ("PJM") charges and credits on a prospective basis to the native fuel cost recovered through the FAC;
- Discontinue the benchmark application to purchased power costs eligible to be recovered through the FAC;
- Implement changes to the calculation of the native/non-native sales stacking logic for long-term commitment generating units;
- Update the base cost of fuel amount; and

- Make administrative updates to the tariff page for consistency across riders and to reflect specific requests being made in this proceeding.

Q. PLEASE DISCUSS WHAT THE COMPANY IS PROPOSING FOR FUEL-RELATED PJM CHARGES AND CREDITS.

A. The Company's Madison Generating Station ("Madison") is considered an Indiana resource for MISO purposes, but is not physically located within the MISO footprint; instead it is connected to the PJM transmission grid. As discussed in more detail in the testimony of Mr. Verderame, energy from the station is transferred to MISO using firm transmission service and from an energy perspective it appears the same as other generating units within MISO. In addition to the settlement statements the Company receives from MISO, it also receives settlement statements from PJM, which includes additional charges and credits associated with Madison. Fuel-related charges and credits from MISO have been included in the Company's FAC filings since it began participating in the MISO energy market in 2005. The Company did not begin receiving the PJM settlement statements for Madison until 2012. To date, Duke Energy Indiana has paid or received all the charges and credits associated with Madison and not passed any of the amounts onto the Company's retail customers.

The PJM charges and credits for Madison vary month-to-month. In some months the net amount on the settlement statement is a charge and in other months it's a credit. The total net of the charges and credits for 2012 through 2018 time period is a net credit (payment from PJM) of approximately $1.6

million. Madison station, similar to Duke Energy Indiana's other generating stations, is operated for the benefit of the Duke Energy Indiana customers regardless of its location with the PJM footprint; therefore, the Company believes it is appropriate to include the comparable fuel-related PJM charges and credits, in addition to the MISO fuel-related charges and credits, in the FAC rider on a prospective basis.

Q. PLEASE EXPLAIN WHAT THE COMPANY IS PROPOSING RELATED TO THE PURCHASED POWER BENCHMARK.

A. The Company is currently subject to a purchased power benchmark established by the Commission's August 18, 1999 Order in Cause No. 41363 and the guidance of the Commission in Cause Nos. 38706 FAC45, 38708 FAC45, 38707 FAC56 and 38707 FAC59. The benchmark is not intended to be a cap on recovery but instead has been used to identify when additional review may be needed to ensure the Company's cost of purchased power is reasonable. In his testimony Mr. Verderame discusses how the benchmark is calculated and what requirements must be met in order to recover any purchased power costs above the benchmark in the Company's FAC rider. He further explains that with the operation of the MISO market, the risks that the benchmark was intended to address have been heavily mitigated. The Company is requesting that the purchased power benchmark procedures currently in place for Duke Energy Indiana be permanently waived by the Commission. Even absent the benchmark, the Company's purchased power costs would continue to remain subject to review and approval

in each of the Company's FAC rider filings.

Q. PLEASE EXPLAIN WHAT THE COMPANY IS PROPOSING RELATED TO THE CALCULATION METHODOLOGY USED TO DETERMINE THE NATIVE/NON-NATIVE STACKING OF THE COMPANY'S GENERATION.

A. Today the Company determines what fuel costs are allocated to native customers (included in the FAC Rider) versus non-native customers (included in the Reliability Rider) using a production costing model. At a high-level, the model stacks based on average production costs ranked lowest to highest, with native customers generally being assigned the lowest cost resources. The Company is proposing to change the stacking logic from the current "average production cost" basis to an "incremental production cost basis" for long-term commitment generating units such as coal-fired and combined-cycle natural gas units. Duke Energy Indiana would continue to allocate costs for short-term commitment units, such as combustion turbines, on the existing average production cost basis.

If native fuel costs increase as a result of this change, the additional costs would increase the fuel costs flowing through the FAC rider. Similarly, any decreases to native fuel costs would lower the fuel costs included in the FAC Rider. Changes to non-native fuel costs will be reflected in the Company's non-native sharing mechanism included in the Reliability Rider.

The Company believes this request is reasonable as the incremental cost approach will better align with MISO's actual dispatch logic and will more

equitably and appropriately allocate fuel costs between native and non-native customers.

Please refer to Company witness Mr. Verderame's testimony for a more in-depth discussion of the Company's stacking process and the proposed changes to the calculation methodology.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT FAC RIDER TARIFF?

A. As discussed earlier in my testimony, the Company is proposing to update the base cost of fuel used to calculate the FAC Rider rate. The new proposed base cost of fuel is 26.955 mills per kWh, as compared to the current factor of 14.484 mills per kWh.

The Company is proposing some minor cosmetic and format changes to get more consistency across its various rider and rate tariffs and resetting the tariff numbering. Also, the Company is proposing to remove the gross-up factor currently reflected in the FAC, assuming the Commission approves the proposal discussed in Ms. Graft's testimony to add Utility Receipts Tax ("URT") directly to the customers' bills rather than including in each rider factor.[1]

Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the FAC Rider are attached to my testimony as Petitioner's Exhibit 5-G (SES) and 5-H (SES). They are also

[1] The Direct Testimony of Company witness Ms. Graft will explain the Company's proposal to include URT on customer bills in lieu of including it as a cost of service item and will support the *pro forma* adjustment to remove URT from the cost of service.

included with the complete set of base rate and other rider tariffs that are filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). The complete rider with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

B. Regional Transmission Operator ("RTO") Rider

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS RTO RIDER?

A. The Company is proposing the following changes to the RTO Rider:

- Add non-fuel related PJM charges and credits on a prospective basis to the comparable MISO amounts currently included in the rider;
- Update the proposed annual base amounts for RTO non-fuel costs and RTO transmission revenues used in the rider calculation;
- Modify the factor calculation for HLF customers to be billed on KW demand rather than on kWh sales; and
- Make administrative updates to the tariff page for consistency across riders and to reflect specific requests being made in this proceeding.

Q. WHAT IS THE COMPANY PROPOSING FOR NON-FUEL RELATED PJM CHARGES AND CREDITS?

A. As discussed in more detail above for the FAC Rider, the Company is currently receiving settlement statements from both PJM (for Madison) and MISO, but is only including the charges and credits from the MISO statements in its base rates and/or applicable rider rates to retail customers. The Company is proposing in

this proceeding to include all RTO non-fuel charges and credits and transmission revenues (both from PJM and MISO) on a prospective basis in its RTO rider filings. The Company believes this request is reasonable as Madison is operated for the benefit of the Duke Energy Indiana customers.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT RTO RIDER TARIFF?

A. The Company is proposing to update the RTO non-fuel and transmission revenues amounts built into base rates and track the actual amounts experienced for these items above and below the amounts in base rates. In accordance with the Company's proposal, the new base amounts reflect both PJM and MISO charges and credits.

The Company is also proposing to update the calculation of the RTO Rider factor for HLF customers to bill on KW demand rather than kWh sales. This proposed methodology is consistent with how the HLF factors are currently calculated for the Company's Environmental and Renewables Riders.

The Company is proposing some minor cosmetic and format changes to get more consistency across its various rider and rate tariffs and resetting the tariff numbering, including modifying the name of this rider from MISO to RTO to reflect the inclusion of applicable amounts from both MISO and PJM. In addition, the Company is proposing to update the revenue conversion factors to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding and remove the provision for utility receipts tax.

Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the RTO Rider are attached to my testimony as Petitioner's Exhibit 5-I (SES) and 5-J (SES). They are also included with the complete set of base rate and other rider tariffs that are filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). The complete rider with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

C. Reliability Rider

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS RELIABILITY RIDER?

A. The Company is proposing the following changes to the Reliability Rider (Rider 70):

- Retaining the non-native margin sharing mechanism but resetting the base amount to zero. The Company proposes to continue sharing 50/50 between customers and shareholders non-native margins realized during the reporting period for the rider, including both positive and potentially negative margins;
- Implementing a new sharing mechanism (or modify the existing non-native mechanism) to share 50/50 between customers and shareholders in margins realized on short-term bundled non-native sales.
- Implement changes to the calculation of the native/non-native sales stacking logic for long-term commitment generating units;
- Modify the capacity portion of the rider to allow for any differential in

capacity costs and/or revenues related to Madison station;

- Update the proposed annual base amount for Power Share® bill credits;
- Modify the factor calculation for HLF customers to be billed on KW demand rather than on kWh sales; and
- Make administrative updates to the tariff page for consistency across riders and to reflect specific requests being made in this proceeding.

Q. WHAT CHANGE IS THE COMPANY PROPOSING TO THE CURRENT NON-NATIVE SHARING MECHANISM WITHIN THIS RIDER?

A. The Company is proposing to retain this mechanism but reset the base amount to zero. Non-native margins, both above and below zero, would be shared equally between the Company and customers with no specific amount embedded in base rates. As described in more detail in the testimony of Company witness Mr. Verderame, this proposal is reasonable as the Company has experienced significant variability in actual non-native margins realized since the Rider was implemented in the last base rate case. Given this variability, the Company believes that accounting for this item through a tracking mechanism is more appropriate than building an amount into base rates.

Q. CAN YOU PLEASE DESCRIBE WHAT THE COMPANY IS REFERRING TO AS SHORT-TERM BUNDLED NON-NATIVE SALES?

A. Yes. The Company is using this term to describe a newer type of non-native contract that combines sales of both capacity and energy and is short-term in nature (five years or less). The negotiated contract prices will cover the energy

costs and will make a contribution to fixed costs. The Company believes that these short-term bundled non-native agreements can be structured to meet a changing wholesale customer need and can be priced to compete at current market prices. For a more detailed discussion on this topic, please refer to the testimony of Company witness Mr. Verderame.

Q. PLEASE EXPLAIN HOW THE COMPANY IS CURRENTLY ACCOUNTING FOR THE ONE EXISTING SHORT-TERM BUNDLED NON-NATIVE CONTRACT.

A. The Company currently has one short-term bundled non-native contract expiring in 2021. As the contract terms for traditional native wholesale contracts have come to an end, some have not been renewed due to the current low-cost energy and capacity pricing available in MISO. This one short-term bundled non-native contract was priced to be competitive within the MISO market. The pricing for this contract is below the Company's fully embedded costs, but above the variable costs, such that it results in an overall net contribution to the Company's fixed costs. Absent this contribution, the retail customers would bear these costs coming out of a retail base rate case where a new cost of service study is completed. Between retail rate cases, the Company has not updated its cost of service study and therefore no ratemaking impacts have been recognized to date for customers as a result of this one particular contract.

Q. WHAT IS THE COMPANY PROPOSING IN THIS PROCEEDING FOR THE CURRENT (AND ANY FUTURE) SHORT-TERM BUNDLED NON-

NATIVE SALES?

A. The Company is proposing to include the margin from the one existing short-term bundled non-native sale, and any similar sales made in the future, within the Reliability Rider to be shared equally (50/50) between the Company and customers. This proposal provides a way for retail customers to realize a benefit as a result of the contribution to fixed costs made from these sales on a prospective basis.

Q. WHAT CHANGES ARE BEING PROPOSED TO THE NATIVE/NON-NATIVE COST ALLOCATIONS?

A. As discussed in more detail above for the FAC Rider, and in the testimony of Company witness Mr. Verderame, the Company is proposing to change the stacking logic in its production costing model from the current "average production cost" basis to an "incremental production cost" basis for long-term commitment generating units (*i.e.*, coal-fired and combined-cycle natural gas units). This production costing model is used to determine native versus non-native fuel costs. Any changes to native fuel costs resulting from a change in the stacking logic would be reflected in the FAC Rider and any impacts to non-native fuel costs would flow through the non-native sharing mechanism in the Reliability Rider. The Company believes this proposal is reasonable as it more closely aligns with MISO's dispatch logic and will result in a more equitable allocation of fuel costs between native and non-native customers.

Q. WHAT CHANGES ARE BEING PROPOSED TO THE RIDER WITH REGARDS TO CAPACITY COSTS AND/OR REVENUES?

A. As more fully described in the testimony of Mr. Verderame, there have been changes recently to the MISO Resource Adequacy Construct that impact Duke Energy Indiana's use of Madison as a capacity resource. MISO has made a change, effective June 1, 2019 for the 2019/2020 Delivery Year, in how it will value capacity resources located outside the MISO footprint. This change has impacted the Company's Madison station, which is now being considered a PJM external zone resource and could therefore clear the annual MISO capacity auction at a different price than the Company's other generating assets. There was no price difference experienced during the 2019/2020 auction; however, price separation could occur in future auctions. To address situations like Madison and other similarly situated generation units, MISO created a hedge instrument called Historical Unit Consideration ("HUC") that are allocated to generators like Madison and are intended to fund the differential. Given these recent changes, the Company is proposing that in prospective Reliability Rider filings no capacity revenues would flow through the rider until the native load charges have been met. If capacity costs have been offset, further revenues from capacity sales and HUC payments could be allocated as non-native sales margin and shared equally through the rider. If capacity costs for native load exceed all capacity revenues, the differential will be recovered in the same way it is today.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT TARIFF FOR THE RELIABILITY RIDER?

A. Yes. The Company is proposing to update the annual base amount for bill credits under the Power Share® program.

The Company is also proposing to update the calculation of the Reliability Rider factor for HLF customers to bill on KW demand rather than kWh sales. This proposed methodology is consistent with how the HLF factors are currently calculated for the Company's Environmental and Renewables Riders and with what is proposed for the RTO Rider.

The Company is also proposing some minor cosmetic and format changes to get more consistency across its various rider and rate tariffs and resetting the tariff numbering. Further, the Company is proposing to update the revenue conversion factors to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding and remove the provision for utility receipts tax.

Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the Reliability Rider are attached to my testimony as Petitioner's Exhibit 5-K (SES) and 5-L (SES). They are also included with the complete set of base rate and other rider tariffs that are filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). The complete rider with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

D. Renewables Rider

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS RENEWABLES RIDER?

A. The Company is proposing to roll the net book value (original cost investment less accumulated depreciation) of all in-service renewables plant as of the end of the Test Period into base rates. Additionally, the Test Period level of O&M will be included in base rates, as will the depreciation associated with the investment rolled into rate base.

At the time of implementation of the new base rates resulting from this proceeding, the Renewables Rider will be revised to:

- remove the investment and O&M amounts included in base rates;
- recalculate the depreciation on the remaining investment (if any) using the new depreciation rates approved in this proceeding;
- change the 10.5% ROE used in the cost of capital calculation to the new ROE approved in this proceeding;
- update the calculation to begin reconciling return, in addition to the current practice of reconciling operating expenses; and,
- change the allocations to rate classes used in the calculation of rates to use the final 4CP production demand allocators from this proceeding instead of the revenue requirements from Cause No. 42359; and
- make administrative updates to the tariff page for consistency across riders and to reflect specific requests being made in this proceeding.

This proposed treatment and changes are in accordance with the terms of the Settlement Agreements approved in Cause Nos. 44734 and 44767 approving rate recoveries for Crane Solar and Markland Uprate projects, respectively.

Q. UNDER THE COMPANY'S PROPOSAL, ARE THERE ANY OTHER ITEMS INCLUDED IN THE RENEWABLES RIDER THAT WILL NOT BE BUILT INTO BASE RATES?

A. Yes. The Company is proposing that post-in-service carrying costs and any credits from the sale of RECs not be included in base rates, but rather continue to be tracked in the Renewables Rider. The post-in-service carrying costs and REC sales are non-recurring and variable in nature, so these items would be best managed through the tracker, until such time as the Renewable Rider is no longer warranted.

In addition, once the Company is able to utilize the investment tax credits ("ITC") for the applicable renewable projects on its corporate consolidated federal income tax return, an additional credit for the retail jurisdictional portion of the associated ITC amortization would be included in the Renewable Rider. These credits have not been included in the proposed base rates in this proceeding to ensure compliance with the federal income tax normalization requirements because the Company will not be able to utilize the credits until after the Test Period, as discussed in the Direct testimonies of Company witnesses Ms. Douglas and Mr. John R. Panizza.

Q. ARE THE COMPANY'S RATEMAKING PROPOSALS REGARDING RENEWABLES INVESTMENT AND COSTS CURRENTLY INCLUDED IN THE RENEWABLES RIDER REASONABLE?

A. Yes. The Company's proposal is consistent with past practice in Indiana to subsequently include in base rates in-service plant receiving CWIP ratemaking treatment via a tracker. The Company's proposed treatment is also in accordance with the terms of the Crane Solar and Markland Uprate Settlement Agreements. To continue to track the post-in-service carrying costs and any REC sale net proceeds in the Renewables Rider, along with any incremental new investment and related depreciation and O&M, is a reasonable way to recover the non-routine and variable Renewables Rider costs.

Q. HOW WILL THE COMPANY IMPLEMENT THE CHANGES TO THE RENEWABLES RIDER ONCE NEW BASE RATES ARE APPROVED?

A. The Company will file revised rate schedules resetting the then-current rates to remove the amounts included in base rates and adjust the ROE, revenue conversion factors, and allocation factors. This will be done concurrently with filing the new base rate tariffs, with both base rates and rider rate changes to be implemented on a service-rendered basis.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT RENEWABLES RIDER TARIFF?

A. Yes. The Company is proposing some minor cosmetic and format changes to get more consistency across its various rider and rate tariffs and resetting the tariff

numbering. In addition, the Company is proposing reconciliation of the return component of the Renewable Rider in addition to the operating costs portion, consistent with its proposal for Rider 62, and is updating its language to reflect that change. Further, the Company is proposing to update the revenue conversion factors to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding and remove the provision for utility receipts tax.

Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the Renewables Rider are attached to my testimony as Petitioner's Exhibit 5-M (SES) and 5-N (SES). They are also included with the complete set of base rate and other rider tariffs that are filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). The complete rider with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

VI. DEFERRAL AND COST RECOVERY REQUESTS

A. Storm Normalization Reserve

Q. WHAT IS THE COMPANY PROPOSING RELATED TO MAJOR STORM EXPENSES?

A. The Company is seeking approval of its request to build into retail base rates a normalized level of major storm expenses of approximately $12.7 million based on a five-year historical average of such costs for calendar years 2013 through 2018. A *pro forma* adjustment was made to increase the Test Period amount for

storms from $10.0 million to the $12.7 million level. In addition to establishing a normalized level in base rates, the Company is proposing to establish a Major Storm Damage Restoration Reserve ("Major Storm Reserve") to track differences between the operating costs incurred and the amount collected in base rates. Any under-recovery would be recorded to a Regulatory Asset and any over-recovery would be recorded as a Regulatory Liability. The net amount for the Major Storm Reserve would be addressed for recovery in the next retail base rate case.

Q. FOR PURPOSES OF THIS PROPOSAL, HOW IS THE COMPANY DEFINING A MAJOR STORM?

A. Company witness Ms. Cicely M. Hart provides information in her testimony on this subject. Ms. Hart's testimony includes a table showing Duke Energy Indiana's historical 2013 through 2018 transmission and distribution costs incurred for major storms based on Major Event Days. Generally speaking, a storm is classified as a Major Event Day when a major reliability event causes a utility to shift into a crisis mode of operation in order to adequately respond. As further described in Ms. Hart's testimony, the Institute of Electrical and Electronic Engineers ("IEEE") 1366 statistically defines a major event day as a day in which the daily system Average Interruption Duration Index ("SAIDI") exceeds a threshold value (calculated from a 5-year average daily SAIDI). See Workpaper OM3-SES for the supporting calculation for five-year historical average for major storm costs that was used to determine the normalized level.

Q. HOW DOES THE COMPANY PLAN TO ADDRESS ANY UNDER- OR OVER-RECOVERY IN THE MAJOR STORM RESERVE IN THE NEXT BASE RATE CASE?

A. In its next retail base rate case, Duke Energy Indiana proposes to include an amortization in the cost of service to either reduce the cost of service for any over-recovery or increase the cost of service for any under-recovery in the Major Storm Reserve at the end of the historical base period.

Q. WHY DOES THE COMPANY BELIEVE IT IS APPROPRIATE TO ESTABLISH A MAJOR STORM RESERVE?

A. As evidenced by the historical cost information shown in Ms. Hart's testimony, the costs for Major Storms vary significantly year-to-year based on the actual number of Major Event Days declared and the types of restoration efforts required. During the 2013 to 2018 historical period alone, costs varied from a low of $6.5 million in one year to a high of $21.4 million in another year. Although the Company is proposing to normalize Major Storm costs for establishing base rates, the timing, frequency, and costs for such Major Storms are unpredictable and therefore challenging for the Company to establish a precise amount in base rates to cover its prudently incurred costs (nothing more or nothing less). The Company believes its proposal to establish a Major Storm Reserve is reasonable and balances the interests of both the Company and its customers by smoothing out these costs and providing for the Company to be able to recover no more or less than its actual costs.

B. Regulatory Asset Request for Native SO_2 EA Recovery

Q. WHAT SPECIFICALLY IS THE COMPANY REQUESTING?

A. As discussed earlier in my testimony, the Company is proposing to transfer the native SO_2 EAs from the EA inventory account to a new Regulatory Asset account. The new Regulatory Asset would be amortized over a proposed twelve-year period, which represents the estimated average remaining life of the Company's steam generation stations (specifically Cayuga and Gibson stations). Assuming the Commission approves this request, at the time new rates go into effect, the native SO_2 EA consumption expense would decrease to zero and the Company would begin recognizing the regulatory asset amortization expense.

Q. WHY IS THE COMPANY REQUESTING THIS NEW REGULATORY ASSET?

A. With changing environmental rules, the Company believes it is unlikely that it will recover the native SO_2 EA costs over a reasonable period of time if the amounts are left in the inventory account. Based on the forecasted native SO_2 consumption expense for 2020, if the Company received no additional allotments of zero cost SO_2 EAs from the EPA after 2020, it will take over 43 years to utilize the forecasted EA inventory balance at the end of 2020. Adding these zero-cost EAs to the inventory at the beginning of each year will continue to lower the associated weighted average cost of inventory that is then used to calculate the associated native consumption expense currently recovered through the Company's Standard Contract Rider No. 63 – SO_2, NOx and Hg Emission

Allowance Adjustment. Absent special regulatory treatment, it is unlikely that the Company will ever fully recover these costs.

Q. IS THE COMPANY'S PROPOSAL REASONABLE?

A. Yes, the costs for the native SO_2 EAs were prudently incurred on behalf of the Company's native customers. The Company's proposal to recover these costs over the estimated remaining lives of the generating assets driving these costs is reasonable.

C. Requested Accounting Treatment

Q. IS THE ACCOUNTING TREATMENT PROPOSED BY THE COMPANY IN ACCORDANCE WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")?

A. Yes. GAAP specifically discusses the accounting for a regulator's actions designed to protect a utility from the effects of regulatory lag. Topic 980 of the Financial Accounting Standards Board's Accounting Standards Codification ("ASC") covers the accounting guidance for regulated operations formerly provided in Statement of Financial Accounting Standards No. 71. Costs associated with regulatory lag can be capitalized for accounting purposes, provided the provisions of ASC 980-340-25-1 are met. The guidance states:

> Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met: (a) It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes and (b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred

> cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost. A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

Q. DO YOU HAVE AN OPINION AS TO THE APPROPRIATENESS OF AND THE ACTION REQUIRED BY THE COMMISSION TO ALLOW FOR THE REQUESTED ACCOUNTING TREATMENT?

A. Yes. In my opinion, the accounting treatment requested by the Company is appropriate from a ratemaking perspective, and such treatment will minimize the timing differences between cost recognition on the Company's books and cost recovery. In order for the Company to defer the Major Storm Reserve and native SO_2 EA costs as regulatory assets, it must be probable that such costs will be recovered through rates in future periods. In order to satisfy the probability standard, the Commission's Order in this proceeding should specifically approve the accounting and ratemaking treatment proposed by Duke Energy Indiana.

VII. CONCLUSION

Q. WERE PETITIONER'S EXHIBITS 5-A (SES) THROUGH 5-O (SES) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

ATTACHMENT 2

PETITIONER'S EXHIBIT 5-C (SES)
Duke Energy Indiana 2019 Base Rate Case
Other Taxes
Schedule OTX12

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Allocated Payroll Tax Expense for Electric Vehicle Pilot Program

(Thousands of Dollars)

This pro forma adjustment is to remove allocated payroll taxes associated with the Electric Vehicle Pilot Program. Amounts to be proposed for deferral in the subdocket proceeding.

Line No.	Description	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Account 0408960 - Allocated Payroll Taxes [2/]	$ 5	$ -	$ (5)	1
2	Total	$ 5	$ -	$ (5)	2

[1/] To PETITIONER'S EXHIBIT 4-E (DLD).

[2/] See: MSFR Workpaper OM4-SES.

CORRECTED REBUTTAL TESTIMONY OF SUZANNE E. SIEFERMAN, DIRECTOR, RATES AND REGULATORY PLANNING ON BEHALF OF DUKE ENERGY INDIANA, LLC CAUSE NO. 45253 BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Suzanne E. Sieferman, and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company") as Director, Rates and Regulatory Planning. Duke Energy Indiana is a wholly owned, indirect subsidiary of Duke Energy Corporation.

Q. ARE YOU THE SAME SUZANNE SIEFERMAN THAT PRESENTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I am responding to various issues and recommendations included in the testimony of the Indiana Office of the Utility Consumer Counselor ("OUCC") witnesses Mr. Lane Kollen, Dr. Peter M. Boerger, and Mr. Anthony A. Alvarez, in the testimony of the Duke Industrial Group ("IG") witness~~es~~ Mr. James R. Dauphinais ~~and Mr. Michael P. Gorman~~, and in the testimony of Kroger witness Mr. Justin Bieber.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. I've organized my testimony by topic rather than by individual witness. The

topics I am addressing are as follows:

- Rate Base – Forecasted Coal Inventory
- Major Storm Expenses – Normalization and Major Storm Reserve Proposal
- Account 575 Budget Adjustment - Rider 68 Impacts
- Reliability Rider

II. RATE BASE – FORECASTED COAL INVENTORY

Q. PLEASE EXPLAIN HOW THE COMPANY'S FORECASTED COAL INVENTORY WAS CALCULATED.

A. The forecasted coal inventory amounts were developed starting with the actual coal inventory balances by station (in tons and dollars) at December 31, 2018 and building up the inventories assuming the monthly purchases (tons and dollars) per the forward plan and the monthly consumption amounts based on the burn projections and associated per ton pricing from the same GenTrader model run used to support the native fuel expense forecast.

Q. HOW DID THE FORECASTED COAL INVENTORY LEVELS AT THE END OF 2020, WHICH WERE CALCULATED USING THIS APPROACH, COMPARE TO THE COMPANY'S TARGET INVENTORY LEVELS?

A. The forecasted coal inventory levels at the end of the 2020 test period for Cayuga, Edwardsport, and Gibson generating stations were 47, 46 and 43 full load burn ("FLB") days, respectively. As discussed in the Direct Testimony of Company witness Mr. Brett Phipps, while the day-to-day inventory levels will fluctuate, the

Company manages to an overall target inventory level of 45 FLB days for each of these stations.

Q. WHAT DOES OUCC WITNESS MR. KOLLEN RECOMMEND WITH REGARDS TO THE COMPANY'S FORECASTED COAL INVENTORY?

A. Mr. Kollen recommends that the forecasted coal inventories for Cayuga and Edwardsport be reduced to the target number of days burn (*i.e.*, 45 days). His explanation for this recommendation is that it is unreasonable that the forecasted inventory levels be anything greater than the target inventory levels.

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION?

A. No. Given the inventory levels included in the Company's 2020 forecast and reflecting the roll-forward approach described earlier result in levels close to the 45-day target levels, the Company deems the forecast to be reasonable and therefore no *pro forma* adjustments need to be made.

III. MAJOR STORM EXPENSES

Q. PLEASE SUMMARIZE THE COMPANY'S RECOMMENDATIONS REGARDING MAJOR STORMS.

A. The Company has proposed to normalize the level of Major Storm expenses in the 2020 forecasted test period based upon a five-year historical average. In addition, the Company has asked that a Major Storm Damage Restoration Reserve ("Major Storm Reserve") be established. The base level would be set at the five-year historical average amount of $12.7 million and the Company would track differences between the operating costs incurred and the amount collected in base

rates. Any under- or over-recovery would be recorded to a Regulatory Asset or Regulatory Liability account, respectively. The regulatory treatment of the net Major Storm Reserve amount would be addressed as part of the Company's next retail base rate case.

Q. WHAT HAS OUCC WITNESS MR. ALVAREZ SUGGESTED WITH REGARDS TO THE COMPANY'S PROPOSALS?

A. Mr. Alvarez has suggested that the Company's request for a Major Storm Reserve be denied unless the Company agrees to develop an operational plan to manage storm restoration activities. He recommends this operational plan should be integrated within the vegetation management and TDSIC programs. Assuming the Company agrees to develop the operational plan he suggests, Mr. Alvarez agrees with the Company's proposal to establish a Major Storm Reserve but suggests that the base level should be set at $6.0 million instead of the $12.7 million level requested.

Q. DOES MR. ALVAREZ OFFER A SUGGESTED ALTERNATIVE IF THE COMPANY DOES NOT AGREE TO HIS NEW OPERATIONAL PLAN OR IF THE COMMISSION DENIES DUKE ENERGY INDIANA'S PROPOSAL TO ESTABLISH A MAJOR STORM RESERVE?

A. In the event the Company does not agree to establish Mr. Alvarez's new operational plan, or if the Commission denies the Company the authority to establish a Major Storm Reserve, he recommends that $5 million be embedded in base rates to represent an ongoing level for major storm expenses.

Q. DOES MR. ALVAREZ HAVE ANY BASIS FOR HIS $6 MILLION STORM RESERVE LEVEL AND $5 MILLION BASE AMOUNT RECOMMENDATIONS FOR STORM RESTORATION COSTS?

A. Not that I am aware of. Whereas, the $12.7 million level proposed by Duke Energy Indiana is based on an average of actual historical costs, Mr. Alvarez's recommendations appear to be arbitrary and not supported by any evidence. In fact, the rationale provided by Mr. Alvarez for these amounts appears to be his baseless claim that the Company has acted imprudently regarding its storm restoration efforts and therefore needs an incentive (*i.e.* disallowance) to reduce its costs to restore electric service to its customers after major storm events by reducing the Company's request by half. It is not disputed that the costs to restore service after major storms are both unpredictable and vary significantly year-to-year, therefore setting a normalized ongoing level based on averaging historical results over some reasonable period is sound practice. Comparing the recommended level to both a three-year average of $16.6 million and a seven-year average of $11.1 million, illustrates that the $12.7 million level proposed is reasonable.

Q. DO YOU AGREE WITH MR. ALVAREZ'S RECOMMENDATIONS?

A. I do not agree with Mr. Alvarez's recommendations. As discussed in greater detail in the Rebuttal Testimony of Company witness Ms. Cicely Hart, the Company already has an effective process in place to respond to major storms in a prudent and cost-effective manner. Further Ms. Hart provides additional

information that explains the higher level of costs incurred for major storm restoration in 2018. Mr. Alvarez's recommendations appear to be addressing his claim that the Company has not provided evidence in this proceeding that it has prudently managed storm expenses and therefore the OUCC and the Commission must provide the Company with an incentive to act prudently by implementing his recommended operational plan and disallowing recovery of costs in excess of his arbitrary $6 million base amount.

Q. HAS THE COMMISSION APPROVED SIMILAR STORM RESERVE TREATMENT FOR OTHER INDIANA ELECTRIC UTILITIES?

A. Yes. The Commission has approved similar Major Storm Reserve concepts for use by other Indiana electric utilities in recent base rate case proceedings. Indiana Michigan Power Company was granted approval for a Major Storm Restoration reserve in Cause No. 44075 and again in Cause No. 44967. The Commission also approved the creation of a Major Storm Damage Restoration Reserve for Indianapolis Power & Light Company in Cause No. 44576 and again in Cause No. 45029.

Q. AFTER REVIEWING MR. ALVAREZ'S TESTIMONY, DO YOU RECOMMEND ANY CHANGES TO YOUR ORIGINAL PROPOSAL ON NORMALIZED MAJOR STORM EXPENSES AND THE NEW MAJOR STORM RESERVE?

A. No. I continue to support the appropriateness of the *pro forma* adjustment made to set a normalized level of major storm expenses of $12.7 million based on the

actual major storm expenses incurred during the five (5) year period of 2014 to 2018. Further, I fully support the appropriateness of establishing the Major Storm Reserve. As acknowledged by Mr. Alvarez, the reserve accounting balances customer and utility interests by providing a way for customers to pay no more (or less) than what the Company incurs for such restoration efforts and allows the Company an opportunity to potentially recover prudently incurred costs necessary to timely restore power after significant storms if that level exceeds what is built into base rates. Storm restoration costs are volatile and highly dependent on storm events and therefore largely outside of the Company's control. A Major Storm Reserve recognizes the difficulty with estimating this cost item, while assuring recovery of prudent costs.

IV. ACCOUNT 575 BUDGET ADJUSTMENT – RIDER 68 IMPACTS

Q. WHAT WAS OUCC WITNESS MR. KOLLEN'S RECOMMENDATION RELATED TO ACCOUNT 575 - MARKET MONITORING AND COMPLIANCE?

A. Mr. Kollen has recommended that the Company make a $2 million reduction to account 575 in the 2020 forecasted test period, as it was noted in a discovery request response that the account was "potentially overstated" in the budget.

Q. HOW HAS THE COMPANY RESPONDED TO MR. KOLLEN'S RECOMMENDATION?

A. Company witness Mr. Christopher M. Jacobi has stated in his Rebuttal Testimony that he does not oppose Mr. Kollen's recommendation to make this reduction to

the account 575 expense in the 2020 forecasted test period and that such reduction will be made.

Q. WHAT IMPACT DOES THIS ADJUSTMENT HAVE TO RIDER 68?

A. In my direct testimony in this proceeding, I provided information on proposed changes to Rider 68, including updated tariff sheets. The updated tariff sheets reflect the new base level of non-fuel RTO costs and revenues that the Company will be comparing to actual costs incurred to determine what will be included in the rider. The base level of non-fuel RTO costs of $67.9 million was calculated using the amounts in the 2020 forecasted test period that would be includable in the rider. With one of those amounts (account 575) being reduced by $2 million, it's necessary to make a corresponding adjustment to the base level of non-fuel RTO costs for Rider 68 (RTO tracker) purposes. Petitioner's Exhibit 36-A (SES) is a schedule showing the calculation of the revised base level of non-fuel RTO costs. Petitioner's Exhibit 36-B (SES) is an updated clean version of the proposed Rider 68 tariff reflecting the new base level amount of $65.9 million.

V. RELIABILITY RIDER (RIDER 70)

Q. PLEASE SUMMARIZE WHAT CHANGES THE COMPANY PROPOSED TO ITS RELIABILITY RIDER WITH REGARDS TO THE NON-NATIVE SHARING PROVISION.

A. The Company proposed the following changes to the Reliability Rider relative to the non-native sharing provision:

- Retain non-native margin sharing mechanism at 50/50 (on traditional non-

native sales to MISO) but reset base amount to zero and allow for sharing of both positive and negative net margins and

- Implement a new sharing mechanism (or modify existing one) to share 50/50 on margins realized on short-term bundled non-native sales.

Q. WHAT HAVE THE INTERVENORS RECOMMENDED RELATED TO THE NON-NATIVE SHARING PROPOSAL FOR TRADITIONAL NON-NATIVE SALES TO MISO?

A. The primary intervenors offering testimony on these proposals were the OUCC's witness Dr. Boerger, the IG's witness Mr. Dauphinais, and Kroger's witness Mr. Justin Bieber. With regards to the Company's proposal to retain the non-native sharing mechanism at 50/50 but reset the base amount to zero, none of the intervening parties were in favor of this proposal. The OUCC's Dr. Boerger was not opposed to resetting the base amount to zero but suggested in that instance that customers should receive 100% of any positive margins. He went on to suggest that even if the Company agreed to build an amount into base rates, he believes that customers should receive a larger percentage of sharing than 50%. The IG's Mr. Dauphinais also took the position that if the base amount is set at zero then customers should receive 100% of any positive margins. Kroger's Mr. Bieber indicated that if the Commission approved the 50/50 sharing the Company proposed he would like to see an amount embedded in base rates. He suggests an amount equal to what was included in the 2020 forecasted test period ($2.5 million). In the event the Company builds zero in base rates, he proposes that

customers should receive 100% of margins. Company witness Mr. Swez provides detailed Rebuttal Testimony on this proposal responding to each of these intervenors' positions. In his Rebuttal Testimony, Mr. Swez states that the Company is agreeable to revising its proposal to allow for 100% of net margins on the traditional non-native sales to MISO to be allocated to customers, with zero being built into base rates for these sales.

Q. WHAT EFFECT DOES THIS CHANGE IN THE COMPANY'S PROPOSAL HAVE ON THE RELIABILITY RIDER (FILED ANNUALLY IN CAUSE NO. 44348, SRA-X)?

A. The Company is proposing to continue using the Reliability Rider mechanism to allocate 100% of these net margins to customers. To facilitate this, the Company will continue stacking fuel costs to determine what fuel costs are assigned to native vs. non-native sales. The net margin on the non-native sales to MISO, which would include fuel assigned to non-native but also such things as non-native emission allowance costs and non-native gas pipeline reservation fees, would then flow through the annual Reliability Rider and be assigned 100% to customers rather than being shared 50/50 as the Company originally proposed.

Q. WHAT BENEFITS DOES THE COMPANY SEE IN CONTINUING TO USE THE RELIABILITY RIDER MECHANISM TO ALLOCATE 100% OF THE NET MARGINS FROM NON-NATIVE SALES TO MISO TO CUSTOMERS?

A. The Company believes this approach is the most transparent and will allow for cost and revenue data to continue to be tracked separately for native and non-native sales, which will enable the Company to easily quantify the net margins on these specific non-native sales. Absent the Company continuing to report these net margins as a separate component in the Reliability Rider, these amounts would be embedded in the FAC Rider and RTO Riders and not as easy to track.

Q. PLEASE SUMMARIZE WHAT THE INTERVENORS HAVE RECOMMENDED WITH REGARDS TO THE COMPANY'S PROPOSAL ON SHORT-TERM BUNDLED NON-NATIVE SALES.

A. OUCC's Dr. Boerger discussed the Company's proposal on this topic at length and while acknowledging that there is some merit to offering the Company an incentive to initiate and negotiate these types of sales, he argues that customers should receive a greater sharing percentage than 50%. Dr. Boerger also discusses the idea of building an amount into base rates for these types of sales and suggests that the Company should have pursued alternative regulatory treatment for the one existing sale of this type. IG's Mr. Dauphinais suggests alternative treatment of the Company's one existing short-term bundled non-native sale and any future sales of this type and proposes that instead of including these sales in the non-native sales tracker they should instead be treated in a similar manner to long-term native wholesale contracts. Kroger's Mr. Bieber indicated that to the extent the Company is able to receive a share of the margins on these sales, he recommends the Commission order the Company to embed a reasonable level of

margin into base rates. He suggests an amount equal to what was included in the 2020 forecasted test period ($12.7 million for the one existing sale of this type). In the event the Company builds zero into base rates, he proposes that customers should receive 100% of margins. Company witnesses Mr. Swez and Mr. Brian P. Davey respond in their Rebuttal Testimonies to these intervenors' positions.

Q. ARE THERE ANY OTHER INTERVENOR RECOMMENDATIONS RELATED TO THE COMPANY'S SHORT-TERM BUNDLED NON-NATIVE PROPOSAL THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. OUCC witness Dr. Boerger expresses concern in his testimony that the Company did not properly reflect margins in its Reliability Rider from the one existing short-term bundled non-native sale contract that the Company has entered into. He goes on to recommend that the Company be ordered to return the amount of net profit realized on this contract beginning June 1, 2017 (Cause No. 44348 SRA-5) and continuing through the date base rates are changed in this proceeding.

Q. WHAT REASONING DOES DR. BOERGER PROVIDE TO SUPPORT HIS CONTENTION THAT THE COMPANY SHOULD HAVE BEEN INCLUDING ANY MARGIN ON THIS CONTRACT IN ITS RELIABILITY RIDER BEGINNING WITH SRA-5?

A. Dr. Boerger contends that this sale was clearly not a native load sale and therefore should have been considered a non-native sale and included in the Reliability Rider.

Q. HOW DO YOU RESPOND TO DR. BOERGER'S RECOMMENDATION?

A. I disagree with Dr. Boerger's recommendation. As discussed in detail in the Direct Testimony of Mr. John Verderame (adopted by Mr. John Swez) and the Rebuttal Testimony of Mr. Swez, market dynamics have changed in recent years such that wholesale customers are not interested in new long-term wholesale contracts nor in renewing existing ones that are priced at embedded cost. The current short-term bundled non-native contract in question was an initial attempt by the Company to respond to this changing dynamic. The current base rate case is the appropriate time to address the prospective treatment for ongoing wholesale contracts and these newer short-term bundled (*i.e.*, demand and energy) bilateral contracts, which are clearly different than the long-term native load wholesale contracts. Therefore, the Company presented a ratemaking proposal in this proceeding for this new category of short-term bundled non-native sales. These sales are different than the traditional long-term native wholesale sales and differ from the non-native sales of excess generation to MISO that were contemplated in the past for inclusion in the Reliability Rider.

Q. HOW DO YOU BELIEVE SHORT-TERM BUNDLED NON-NATIVE SALES SHOULD BE HANDLED IN THE RELIABILITY RIDER?

A. For the reasons I discuss above, I disagree with Dr. Boerger's recommendation to refund prior net margins realized on this contract through future Reliability Rider filings. I continue to support the Company's original proposal in this proceeding that any net margins from this (and any future) short-term bundled non-native

sales contract, subject to a zero-base amount, should be shared 50/50 with customers through the annual Reliability Rider. As the Rebuttal Testimonies of Mr. Davey and Mr. Swez indicate, this proposal balances the interests of both the Company and its customers by providing an incentive for the Company to negotiate and enter into such contracts and benefitting customers by crediting them through this Rider with some contribution to the Company's fixed cost for generation.

Q. HOW DOES THE COMPANY'S PROPOSED CHANGE TO BEGIN SHARING 100% OF NET MARGINS ON NON-NATIVE MISO SALES IMPACT THE RELIABILITY RIDER?

A. As discussed earlier, even with 100% sharing of net margins on non-native sales of excessive generation to MISO, the Company would like to continue using the Reliability Rider mechanism to flow those margins back to customers. Petitioner's Exhibit 36-C, attached to my Rebuttal Testimony, is an updated clean version of the proposed Rider 70 tariff reflecting this change.

~~**VI. DEFERRAL FOR ELECTRIC TRANSPORTATION PILOT PROGRAM**~~

~~**Q. DID ANY INTERVENORS FILE TESTIMONY OPPOSING THE DEFERRAL REQUEST FOR THE ELECTRIC TRANSPORTATION PILOT PROGRAM ("PILOT PROGRAM") THAT YOU DISCUSSED IN YOUR DIRECT TESTIMONY?**~~

~~A. Yes. Several witnesses filed testimony opposing portions of the Pilot Program, or the entire program, as outlined in the Direct Testimony of Company witness~~

~~Mr. Lang Reynolds. Mr. Reynolds has responded to these opposing positions in his Rebuttal Testimony.~~

~~**Q. IN ADDITION TO THE ARGUMENTS MR. REYNOLDS WILL BE REBUTTING, IS THERE ANYTHING YOU PLAN TO ADDRESS IN YOUR REBUTTAL TESTIMONY?**~~

~~A. Yes. IG witness Mr. Gorman recommends that the Commission deny the Company's deferral request for the Pilot Program and instead seek recovery once the program is complete. Mr. Gorman also shares his concern that the Company proposed a cap for recovery of the capital investment in its Pilot Program but did not propose a cap for its estimated O&M costs.~~

~~**Q. HOW DO YOU RESPOND TO HIS RECOMMENDATION TO DENY THE DEFERRAL REQUEST?**~~

~~A. It is reasonable for the Company to request and the Commission to approve this deferral request. This request is only seeking deferral of current (post 2018) and future costs associated with this new Pilot Program. As outlined in my Direct Testimony, the Company is not requesting deferral treatment for any capital items that are in service at the end of the 2020 test period. Any remaining capital items not yet in service at that time would be deferred, along with deferred depreciation and post-in-service carrying costs, for recovery in a future base rate case. The Commission, IG and all interested parties will have the opportunity to review the cost deferral for the Pilot Program in that future base rate case to determine if costs were reasonable and prudent and recovery should be granted.~~

~~**Q. DO YOU AGREE WITH HIS CONCERN REGARDING THE LACK OF A PROPOSED CAP ON O&M COSTS FOR THE PILOT PROGRAM?**~~

~~A. No. As stated in my Direct Testimony in this proceeding (see page 36, lines 17-22) the total forecasted cost of the Pilot Program is $15.3 million, with $11.4 million of that total being for capital and the remaining $3.9 million for O&M. The Company proposed to cap cost recovery at the $15.3 million estimate excluding proposed carrying costs. This $15.3 million cap is an overall cap covering both capital and O&M spend for the Pilot Program.~~

V~~I~~II. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

CORRECTED REBUTTAL TESTIMONY OF SUZANNE E. SIEFERMAN, DIRECTOR, RATES AND REGULATORY PLANNING ON BEHALF OF DUKE ENERGY INDIANA, LLC CAUSE NO. 45253 BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Suzanne E. Sieferman, and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company") as Director, Rates and Regulatory Planning. Duke Energy Indiana is a wholly owned, indirect subsidiary of Duke Energy Corporation.

Q. ARE YOU THE SAME SUZANNE SIEFERMAN THAT PRESENTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I am responding to various issues and recommendations included in the testimony of the Indiana Office of the Utility Consumer Counselor ("OUCC") witnesses Mr. Lane Kollen, Dr. Peter M. Boerger, and Mr. Anthony A. Alvarez, in the testimony of the Duke Industrial Group ("IG") witness Mr. James R. Dauphinais, and in the testimony of Kroger witness Mr. Justin Bieber.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. I've organized my testimony by topic rather than by individual witness. The

topics I am addressing are as follows:

- Rate Base – Forecasted Coal Inventory
- Major Storm Expenses – Normalization and Major Storm Reserve Proposal
- Account 575 Budget Adjustment - Rider 68 Impacts
- Reliability Rider

II. RATE BASE – FORECASTED COAL INVENTORY

Q. PLEASE EXPLAIN HOW THE COMPANY'S FORECASTED COAL INVENTORY WAS CALCULATED.

A. The forecasted coal inventory amounts were developed starting with the actual coal inventory balances by station (in tons and dollars) at December 31, 2018 and building up the inventories assuming the monthly purchases (tons and dollars) per the forward plan and the monthly consumption amounts based on the burn projections and associated per ton pricing from the same GenTrader model run used to support the native fuel expense forecast.

Q. HOW DID THE FORECASTED COAL INVENTORY LEVELS AT THE END OF 2020, WHICH WERE CALCULATED USING THIS APPROACH, COMPARE TO THE COMPANY'S TARGET INVENTORY LEVELS?

A. The forecasted coal inventory levels at the end of the 2020 test period for Cayuga, Edwardsport, and Gibson generating stations were 47, 46 and 43 full load burn ("FLB") days, respectively. As discussed in the Direct Testimony of Company witness Mr. Brett Phipps, while the day-to-day inventory levels will fluctuate, the

Company manages to an overall target inventory level of 45 FLB days for each of these stations.

Q. WHAT DOES OUCC WITNESS MR. KOLLEN RECOMMEND WITH REGARDS TO THE COMPANY'S FORECASTED COAL INVENTORY?

A. Mr. Kollen recommends that the forecasted coal inventories for Cayuga and Edwardsport be reduced to the target number of days burn (*i.e.*, 45 days). His explanation for this recommendation is that it is unreasonable that the forecasted inventory levels be anything greater than the target inventory levels.

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION?

A. No. Given the inventory levels included in the Company's 2020 forecast and reflecting the roll-forward approach described earlier result in levels close to the 45-day target levels, the Company deems the forecast to be reasonable and therefore no *pro forma* adjustments need to be made.

III. MAJOR STORM EXPENSES

Q. PLEASE SUMMARIZE THE COMPANY'S RECOMMENDATIONS REGARDING MAJOR STORMS.

A. The Company has proposed to normalize the level of Major Storm expenses in the 2020 forecasted test period based upon a five-year historical average. In addition, the Company has asked that a Major Storm Damage Restoration Reserve ("Major Storm Reserve") be established. The base level would be set at the five-year historical average amount of $12.7 million and the Company would track differences between the operating costs incurred and the amount collected in base

rates. Any under- or over-recovery would be recorded to a Regulatory Asset or Regulatory Liability account, respectively. The regulatory treatment of the net Major Storm Reserve amount would be addressed as part of the Company's next retail base rate case.

Q. WHAT HAS OUCC WITNESS MR. ALVAREZ SUGGESTED WITH REGARDS TO THE COMPANY'S PROPOSALS?

A. Mr. Alvarez has suggested that the Company's request for a Major Storm Reserve be denied unless the Company agrees to develop an operational plan to manage storm restoration activities. He recommends this operational plan should be integrated within the vegetation management and TDSIC programs. Assuming the Company agrees to develop the operational plan he suggests, Mr. Alvarez agrees with the Company's proposal to establish a Major Storm Reserve but suggests that the base level should be set at $6.0 million instead of the $12.7 million level requested.

Q. DOES MR. ALVAREZ OFFER A SUGGESTED ALTERNATIVE IF THE COMPANY DOES NOT AGREE TO HIS NEW OPERATIONAL PLAN OR IF THE COMMISSION DENIES DUKE ENERGY INDIANA'S PROPOSAL TO ESTABLISH A MAJOR STORM RESERVE?

A. In the event the Company does not agree to establish Mr. Alvarez's new operational plan, or if the Commission denies the Company the authority to establish a Major Storm Reserve, he recommends that $5 million be embedded in base rates to represent an ongoing level for major storm expenses.

Q. DOES MR. ALVAREZ HAVE ANY BASIS FOR HIS $6 MILLION STORM RESERVE LEVEL AND $5 MILLION BASE AMOUNT RECOMMENDATIONS FOR STORM RESTORATION COSTS?

A. Not that I am aware of. Whereas, the $12.7 million level proposed by Duke Energy Indiana is based on an average of actual historical costs, Mr. Alvarez's recommendations appear to be arbitrary and not supported by any evidence. In fact, the rationale provided by Mr. Alvarez for these amounts appears to be his baseless claim that the Company has acted imprudently regarding its storm restoration efforts and therefore needs an incentive (*i.e.* disallowance) to reduce its costs to restore electric service to its customers after major storm events by reducing the Company's request by half. It is not disputed that the costs to restore service after major storms are both unpredictable and vary significantly year-to-year, therefore setting a normalized ongoing level based on averaging historical results over some reasonable period is sound practice. Comparing the recommended level to both a three-year average of $16.6 million and a seven-year average of $11.1 million, illustrates that the $12.7 million level proposed is reasonable.

Q. DO YOU AGREE WITH MR. ALVAREZ'S RECOMMENDATIONS?

A. I do not agree with Mr. Alvarez's recommendations. As discussed in greater detail in the Rebuttal Testimony of Company witness Ms. Cicely Hart, the Company already has an effective process in place to respond to major storms in a prudent and cost-effective manner. Further Ms. Hart provides additional

information that explains the higher level of costs incurred for major storm restoration in 2018. Mr. Alvarez's recommendations appear to be addressing his claim that the Company has not provided evidence in this proceeding that it has prudently managed storm expenses and therefore the OUCC and the Commission must provide the Company with an incentive to act prudently by implementing his recommended operational plan and disallowing recovery of costs in excess of his arbitrary $6 million base amount.

Q. HAS THE COMMISSION APPROVED SIMILAR STORM RESERVE TREATMENT FOR OTHER INDIANA ELECTRIC UTILITIES?

A. Yes. The Commission has approved similar Major Storm Reserve concepts for use by other Indiana electric utilities in recent base rate case proceedings. Indiana Michigan Power Company was granted approval for a Major Storm Restoration reserve in Cause No. 44075 and again in Cause No. 44967. The Commission also approved the creation of a Major Storm Damage Restoration Reserve for Indianapolis Power & Light Company in Cause No. 44576 and again in Cause No. 45029.

Q. AFTER REVIEWING MR. ALVAREZ'S TESTIMONY, DO YOU RECOMMEND ANY CHANGES TO YOUR ORIGINAL PROPOSAL ON NORMALIZED MAJOR STORM EXPENSES AND THE NEW MAJOR STORM RESERVE?

A. No. I continue to support the appropriateness of the *pro forma* adjustment made to set a normalized level of major storm expenses of $12.7 million based on the

actual major storm expenses incurred during the five (5) year period of 2014 to 2018. Further, I fully support the appropriateness of establishing the Major Storm Reserve. As acknowledged by Mr. Alvarez, the reserve accounting balances customer and utility interests by providing a way for customers to pay no more (or less) than what the Company incurs for such restoration efforts and allows the Company an opportunity to potentially recover prudently incurred costs necessary to timely restore power after significant storms if that level exceeds what is built into base rates. Storm restoration costs are volatile and highly dependent on storm events and therefore largely outside of the Company's control. A Major Storm Reserve recognizes the difficulty with estimating this cost item, while assuring recovery of prudent costs.

IV. ACCOUNT 575 BUDGET ADJUSTMENT – RIDER 68 IMPACTS

Q. WHAT WAS OUCC WITNESS MR. KOLLEN'S RECOMMENDATION RELATED TO ACCOUNT 575 - MARKET MONITORING AND COMPLIANCE?

A. Mr. Kollen has recommended that the Company make a $2 million reduction to account 575 in the 2020 forecasted test period, as it was noted in a discovery request response that the account was "potentially overstated" in the budget.

Q. HOW HAS THE COMPANY RESPONDED TO MR. KOLLEN'S RECOMMENDATION?

A. Company witness Mr. Christopher M. Jacobi has stated in his Rebuttal Testimony that he does not oppose Mr. Kollen's recommendation to make this reduction to

the account 575 expense in the 2020 forecasted test period and that such reduction will be made.

Q. WHAT IMPACT DOES THIS ADJUSTMENT HAVE TO RIDER 68?

A. In my direct testimony in this proceeding, I provided information on proposed changes to Rider 68, including updated tariff sheets. The updated tariff sheets reflect the new base level of non-fuel RTO costs and revenues that the Company will be comparing to actual costs incurred to determine what will be included in the rider. The base level of non-fuel RTO costs of $67.9 million was calculated using the amounts in the 2020 forecasted test period that would be includable in the rider. With one of those amounts (account 575) being reduced by $2 million, it's necessary to make a corresponding adjustment to the base level of non-fuel RTO costs for Rider 68 (RTO tracker) purposes. Petitioner's Exhibit 36-A (SES) is a schedule showing the calculation of the revised base level of non-fuel RTO costs. Petitioner's Exhibit 36-B (SES) is an updated clean version of the proposed Rider 68 tariff reflecting the new base level amount of $65.9 million.

V. RELIABILITY RIDER (RIDER 70)

Q. PLEASE SUMMARIZE WHAT CHANGES THE COMPANY PROPOSED TO ITS RELIABILITY RIDER WITH REGARDS TO THE NON-NATIVE SHARING PROVISION.

A. The Company proposed the following changes to the Reliability Rider relative to the non-native sharing provision:

- Retain non-native margin sharing mechanism at 50/50 (on traditional non-

native sales to MISO) but reset base amount to zero and allow for sharing of both positive and negative net margins and

- Implement a new sharing mechanism (or modify existing one) to share 50/50 on margins realized on short-term bundled non-native sales.

Q. WHAT HAVE THE INTERVENORS RECOMMENDED RELATED TO THE NON-NATIVE SHARING PROPOSAL FOR TRADITIONAL NON-NATIVE SALES TO MISO?

A. The primary intervenors offering testimony on these proposals were the OUCC's witness Dr. Boerger, the IG's witness Mr. Dauphinais, and Kroger's witness Mr. Justin Bieber. With regards to the Company's proposal to retain the non-native sharing mechanism at 50/50 but reset the base amount to zero, none of the intervening parties were in favor of this proposal. The OUCC's Dr. Boerger was not opposed to resetting the base amount to zero but suggested in that instance that customers should receive 100% of any positive margins. He went on to suggest that even if the Company agreed to build an amount into base rates, he believes that customers should receive a larger percentage of sharing than 50%. The IG's Mr. Dauphinais also took the position that if the base amount is set at zero then customers should receive 100% of any positive margins. Kroger's Mr. Bieber indicated that if the Commission approved the 50/50 sharing the Company proposed he would like to see an amount embedded in base rates. He suggests an amount equal to what was included in the 2020 forecasted test period ($2.5 million). In the event the Company builds zero in base rates, he proposes that

customers should receive 100% of margins. Company witness Mr. Swez provides detailed Rebuttal Testimony on this proposal responding to each of these intervenors' positions. In his Rebuttal Testimony, Mr. Swez states that the Company is agreeable to revising its proposal to allow for 100% of net margins on the traditional non-native sales to MISO to be allocated to customers, with zero being built into base rates for these sales.

Q. WHAT EFFECT DOES THIS CHANGE IN THE COMPANY'S PROPOSAL HAVE ON THE RELIABILITY RIDER (FILED ANNUALLY IN CAUSE NO. 44348, SRA-X)?

A. The Company is proposing to continue using the Reliability Rider mechanism to allocate 100% of these net margins to customers. To facilitate this, the Company will continue stacking fuel costs to determine what fuel costs are assigned to native vs. non-native sales. The net margin on the non-native sales to MISO, which would include fuel assigned to non-native but also such things as non-native emission allowance costs and non-native gas pipeline reservation fees, would then flow through the annual Reliability Rider and be assigned 100% to customers rather than being shared 50/50 as the Company originally proposed.

Q. WHAT BENEFITS DOES THE COMPANY SEE IN CONTINUING TO USE THE RELIABILITY RIDER MECHANISM TO ALLOCATE 100% OF THE NET MARGINS FROM NON-NATIVE SALES TO MISO TO CUSTOMERS?

A. The Company believes this approach is the most transparent and will allow for cost and revenue data to continue to be tracked separately for native and non-native sales, which will enable the Company to easily quantify the net margins on these specific non-native sales. Absent the Company continuing to report these net margins as a separate component in the Reliability Rider, these amounts would be embedded in the FAC Rider and RTO Riders and not as easy to track.

Q. PLEASE SUMMARIZE WHAT THE INTERVENORS HAVE RECOMMENDED WITH REGARDS TO THE COMPANY'S PROPOSAL ON SHORT-TERM BUNDLED NON-NATIVE SALES.

A. OUCC's Dr. Boerger discussed the Company's proposal on this topic at length and while acknowledging that there is some merit to offering the Company an incentive to initiate and negotiate these types of sales, he argues that customers should receive a greater sharing percentage than 50%. Dr. Boerger also discusses the idea of building an amount into base rates for these types of sales and suggests that the Company should have pursued alternative regulatory treatment for the one existing sale of this type. IG's Mr. Dauphinais suggests alternative treatment of the Company's one existing short-term bundled non-native sale and any future sales of this type and proposes that instead of including these sales in the non-native sales tracker they should instead be treated in a similar manner to long-term native wholesale contracts. Kroger's Mr. Bieber indicated that to the extent the Company is able to receive a share of the margins on these sales, he recommends the Commission order the Company to embed a reasonable level of

margin into base rates. He suggests an amount equal to what was included in the 2020 forecasted test period ($12.7 million for the one existing sale of this type). In the event the Company builds zero into base rates, he proposes that customers should receive 100% of margins. Company witnesses Mr. Swez and Mr. Brian P. Davey respond in their Rebuttal Testimonies to these intervenors' positions.

Q. ARE THERE ANY OTHER INTERVENOR RECOMMENDATIONS RELATED TO THE COMPANY'S SHORT-TERM BUNDLED NON-NATIVE PROPOSAL THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. OUCC witness Dr. Boerger expresses concern in his testimony that the Company did not properly reflect margins in its Reliability Rider from the one existing short-term bundled non-native sale contract that the Company has entered into. He goes on to recommend that the Company be ordered to return the amount of net profit realized on this contract beginning June 1, 2017 (Cause No. 44348 SRA-5) and continuing through the date base rates are changed in this proceeding.

Q. WHAT REASONING DOES DR. BOERGER PROVIDE TO SUPPORT HIS CONTENTION THAT THE COMPANY SHOULD HAVE BEEN INCLUDING ANY MARGIN ON THIS CONTRACT IN ITS RELIABILITY RIDER BEGINNING WITH SRA-5?

A. Dr. Boerger contends that this sale was clearly not a native load sale and therefore should have been considered a non-native sale and included in the Reliability Rider.

Q. HOW DO YOU RESPOND TO DR. BOERGER'S RECOMMENDATION?

A. I disagree with Dr. Boerger's recommendation. As discussed in detail in the Direct Testimony of Mr. John Verderame (adopted by Mr. John Swez) and the Rebuttal Testimony of Mr. Swez, market dynamics have changed in recent years such that wholesale customers are not interested in new long-term wholesale contracts nor in renewing existing ones that are priced at embedded cost. The current short-term bundled non-native contract in question was an initial attempt by the Company to respond to this changing dynamic. The current base rate case is the appropriate time to address the prospective treatment for ongoing wholesale contracts and these newer short-term bundled (*i.e.*, demand and energy) bilateral contracts, which are clearly different than the long-term native load wholesale contracts. Therefore, the Company presented a ratemaking proposal in this proceeding for this new category of short-term bundled non-native sales. These sales are different than the traditional long-term native wholesale sales and differ from the non-native sales of excess generation to MISO that were contemplated in the past for inclusion in the Reliability Rider.

Q. HOW DO YOU BELIEVE SHORT-TERM BUNDLED NON-NATIVE SALES SHOULD BE HANDLED IN THE RELIABILITY RIDER?

A. For the reasons I discuss above, I disagree with Dr. Boerger's recommendation to refund prior net margins realized on this contract through future Reliability Rider filings. I continue to support the Company's original proposal in this proceeding that any net margins from this (and any future) short-term bundled non-native

sales contract, subject to a zero-base amount, should be shared 50/50 with customers through the annual Reliability Rider. As the Rebuttal Testimonies of Mr. Davey and Mr. Swez indicate, this proposal balances the interests of both the Company and its customers by providing an incentive for the Company to negotiate and enter into such contracts and benefitting customers by crediting them through this Rider with some contribution to the Company's fixed cost for generation.

Q. HOW DOES THE COMPANY'S PROPOSED CHANGE TO BEGIN SHARING 100% OF NET MARGINS ON NON-NATIVE MISO SALES IMPACT THE RELIABILITY RIDER?

A. As discussed earlier, even with 100% sharing of net margins on non-native sales of excessive generation to MISO, the Company would like to continue using the Reliability Rider mechanism to flow those margins back to customers. Petitioner's Exhibit 36-C, attached to my Rebuttal Testimony, is an updated clean version of the proposed Rider 70 tariff reflecting this change.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.