FILED
May 31, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED JOINT PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC ("NIPSCO") AND ROSEWATER WIND GENERATION LLC (THE "JOINT VENTURE") FOR (1) ISSUANCE TO NIPSCO OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE PURCHASE AND ACQUISITION OF A 102 MW WIND FARM ("THE ROSEWATER PROJECT"); (2) APPROVAL OF THE ROSEWATER PROJECT AS A CLEAN ENERGY PROJECT UNDER IND. CODE § 8-1-8.8-11; (3) APPROVAL OF RATEMAKING AND ACCOUNTING TREATMENT ASSOCIATED WITH THE ROSEWATER PROJECT; (4) AUTHORITY TO ESTABLISH AMORTIZATION RATES FOR NIPSCO'S INVESTMENT IN THE JOINT VENTURE; (5) APPROVAL PURSUANT TO IND. CODE § 8-1-2.5-6 OF AN ALTERNATIVE REGULATORY PLAN INCLUDING ESTABLISHMENT OF JOINT VENTURE THROUGH WHICH THE ROSEWATER PROJECT WILL SUPPORT NIPSCO'S GENERATION FLEET AND THE REFLECTION IN NIPSCO'S NET ORIGINAL COST RATE BASE OF ITS INVESTMENT IN JOINT VENTURE; (6) APPROVAL OF PURCHASED POWER AGREEMENTS THROUGH WHICH NIPSCO WILL RECEIVE THE ENERGY GENERATED BY THE ROSEWATER PROJECT, INCLUDING TIMELY COST RECOVERY PURSUANT TO IND. CODE § 8-1-8.8-11 THROUGH NIPSCO'S FUEL ADJUSTMENT CLAUSE; (7) AUTHORITY TO DEFER AMORTIZATION AND TO ACCRUE POST-IN SERVICE CARRYING CHARGES ON NIPSCO'S INVESTMENT IN JOINT VENTURE; (8) TO THE EXTENT GENERALLY ACCEPTED ACCOUNTING PRINCIPLES WOULD TREAT ANY ASPECT OF JOINT VENTURE AS DEBT ON NIPSCO'S FINANCIAL STATEMENTS, APPROVAL OF FINANCING; (9) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN FOR NIPSCO IN ORDER TO FACILITATE THE IMPLEMENTATION OF THE ROSEWATER PROJECT; AND (10) TO THE EXTENT NECESSARY, ISSUANCE OF AN ORDER PURSUANT TO IND. CODE § 8-1-2.5-5 DECLINING TO EXERCISE JURISDICTION OVER JOINT VENTURE AS A PUBLIC UTILITY.	)	**CAUSE NO. 45194**

INTERVENOR INDIANA COAL COUNCIL, INC.
SUBMISSION OF PROPOSED ORDER

The Indiana Coal Council, Inc. ("ICC"), submits its proposed order attached hereto. ICC thanks NIPSCO for sharing in advance sections 1 through 13 of its proposed order, allowing ICC to simplify its proposed order by proposing language for only those sections where ICC takes exception to NIPSCO's proposed order.

Respectfully submitted,

FROST BROWN TODD LLC

Dated: May 31, 2019

By: ______________________

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STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED JOINT PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC ("NIPSCO") AND ROSEWATER WIND GENERATION LLC (THE "JOINT VENTURE") FOR (1) ISSUANCE TO NIPSCO OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE PURCHASE AND ACQUISITION OF A 102 MW WIND FARM ("THE ROSEWATER PROJECT"); (2) APPROVAL OF THE ROSEWATER PROJECT AS A CLEAN ENERGY PROJECT UNDER IND. CODE § 8-1-8.8-11; (3) APPROVAL OF RATEMAKING AND ACCOUNTING TREATMENT ASSOCIATED WITH THE ROSEWATER PROJECT; (4) AUTHORITY TO ESTABLISH AMORTIZATION RATES FOR NIPSCO'S INVESTMENT IN THE JOINT VENTURE; (5) APPROVAL PURSUANT TO IND. CODE § 8-1-2.5-6 OF AN ALTERNATIVE REGULATORY PLAN INCLUDING ESTABLISHMENT OF JOINT VENTURE THROUGH WHICH THE ROSEWATER PROJECT WILL SUPPORT NIPSCO'S GENERATION FLEET AND THE REFLECTION IN NIPSCO'S NET ORIGINAL COST RATE BASE OF ITS INVESTMENT IN JOINT VENTURE; (6) APPROVAL OF PURCHASED POWER AGREEMENTS THROUGH WHICH NIPSCO WILL RECEIVE THE ENERGY GENERATED BY THE ROSEWATER PROJECT, INCLUDING TIMELY COST RECOVERY PURSUANT TO IND. CODE § 8-1-8.8-11 THROUGH NIPSCO'S FUEL ADJUSTMENT CLAUSE; (7) AUTHORITY TO DEFER AMORTIZATION AND TO ACCRUE POST-IN SERVICE CARRYING CHARGES ON NIPSCO'S INVESTMENT IN JOINT VENTURE; (8) TO THE EXTENT GENERALLY ACCEPTED ACCOUNTING PRINCIPLES WOULD TREAT ANY ASPECT OF JOINT VENTURE AS DEBT ON NIPSCO'S FINANCIAL STATEMENTS, APPROVAL OF FINANCING; (9) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN FOR NIPSCO IN ORDER TO FACILITATE THE IMPLEMENTATION OF THE ROSEWATER PROJECT; AND (10) TO THE EXTENT NECESSARY, ISSUANCE OF AN ORDER PURSUANT TO IND. CODE § 8-1-2.5-5 DECLINING TO EXERCISE JURISDICTION OVER JOINT VENTURE AS A PUBLIC UTILITY.	)	**CAUSE NO. 45194**

ORDER OF THE COMMISSION

Presiding Officers:
James Huston, Chairman
David L. Ober, Commissioner
David Veleta, Senior Administrative Law Judge

[ICC agrees with Joint Petitioner's recitation of procedural history].

1. **Notice and Commission Jurisdiction.** [ICC agrees with Joint Petitioner's statement of notice and jurisdiction].

2. **NIPSCO's Characteristics.** [ICC agrees with Joint Petitioner's statement of NIPSCO's characteristics].

3. **RoseWater's Characteristics.** [ICC agrees with Joint Petitioner's statement of RoseWater's characteristics].

4. **Requested Relief.** [ICC agrees with Joint Petitioner's statement of relief requested].

5. **Statutory Framework.** Joint Petitioners' petition relies on several statutory provisions.

(1) Joint Petitioners claim that Ind. Code § 8-1-2-42(a) authorizes recovery of purchased electricity; however, on its face that statute does not provide specific authority for recovery of purchased electricity costs. Rather Section 42(a) prohibits changes in rates unless approved by the Commission on at least thirty (30) days' notice. It also prohibits a utility for filing for a general increase in its basic rates and charges more frequently than every fifteen (15) months, and creates three (3) enumerated exceptions when the Commission may approve a general increase in basic rates and charges more frequently than every fifteen (15) months. Finally, Section 42(a) excludes from the definition of "general increase in basic rates and charges" changes related solely to the cost of fuel or the cost of purchased gas or purchased electricity or adjustments in accordance with tracking provisions approved by the commission. Accordingly, all Section 42(a) provides with respect to purchased electricity is an exception that allows for increases in rates and charges more frequently than every fifteen (15) months if the change relates to the cost of purchased electricity.

We note further, that the fuel cost tracker mechanism created by Ind. Code § 8-1-2-42(d) does not provide for the tracking and recovery of all purchased electricity costs. Rather it provides for the tracking and recovery of "the cost of fuel included in the cost of purchased electricity." This could not apply to purchased wind or solar electricity since those resources have no fuel costs.

Of course, the reasonable and necessary cost of purchased electricity is a cost of operation and providing service to customers that retail electric utilities may include and recover in their rates and charges, but contrary to Joint Petitioner's contention, there is no special authority for such recovery in Ind. Code § 8-1-2-42.

(2) Joint Petitioners also seek relief under Ind. Code ch 8-1-2.5 which allows the Commission, at the request of an energy utility, to apply an alternative regulatory plan to the utility, and to decline to exercise aspects of the Commission's jurisdiction. Here, Joint Petitioners ask for several elements of alternative regulatory relief. First, Joint Petitioners ask that to the extent necessary the Commission adopt, as an alternative regulatory practice, a tracking provision to be applied in conjunction with NIPSCO's statutory quarterly fuel cost tracker, for

NIPSCO to track and recover the costs it incurs in connection with the RoseWater PPA. Ind. Code § 8-1-2.5-6(e) allows the Commission to approve Joint Petitioner's request if the Commission "finds that such action is consistent with the public interest."

(3) NIPSCO seeks a CPCN and any other necessary approval for its investment in and ownership of a membership interest in RoseWater Wind Generation LLC. As alternative regulatory relief, NIPSCO seeks to be relieved of, or to be found to have complied with, obligations imposed by Ind. Code § 8-1-8.5-5(e) for obtaining a CPCN.

Joint Petitioners also seek declination of jurisdiction over RoseWater Wind Generation LLC. We agree that RoseWater Wind Generation LLC will not own, operate, manage, or control any electric generation facilities, and therefore will not be a public utility as defined by Ind. Code § 8-1-2-1.

(4) Joint Petitioners seek a determination that the RoseWater Project is an eligible Clean Energy Project for purposes of Ind. Code § 8-1-8.8-11. NIPSCO and RoseWater Wind Generation LLC claim to be "eligible businesses" as defined in Ind. Code § 8-1-8.8-6, but they are not. There "eligible business" is defined as "an energy utility" that "undertakes a project to develop alternative energy sources, including renewable energy projects." By reason of its current ownership, operation, management, and control of electric generation facilities, NIPSCO qualifies as "an energy utility" as defined in Ind. Code § 8-1-2.5-2. But more is required to qualify as an "eligible business," namely *undertaking* "a project to develop alternative energy sources, including renewable energy projects."

In prior uncontested proceedings, the Commission has entered orders finding that a utility entering into a PPA for wind energy is an "eligible business" under Ind. Code ch. 8-1-8.8. *See, e.g.* Order in 43393 (Jul 24, 2008); Order in 44362 (Nov. 25, 2013). We note, however, that in those cases no party challenged the status of the petitioner as an "eligible business." Indeed, we expressly so stated in 43362, ¶8 ("No party challenged I&M's status as an eligible business under Chapter 8.8."). Here, Intervenor Indiana Coal Council, Inc. challenges NIPSCO's status as an "eligible business." The Indiana Supreme Court has recently clarified that statutory interpretation is the province of the courts, not the Commission. *NIPSCO Indus. Grp. v. N. Indiana Pub. Serv. Co.*, 100 N.E.3d 234, 241 (Ind. 2018), modified on reh'g (Sept. 25, 2018) ("Separation-of-powers principles do not contemplate a 'tie-goes-to-the-agency' standard for reviewing administrative decisions on questions of law. In discharging our constitutional duty, we pronounce the statutory interpretation that is best and do not acquiesce in the interpretations of others."). However, to decide in the first instance whether to grant the requested relief in this case, we must interpret the statute.

We cannot indulge the broad interpretation of the phrase "undertakes a project to develop" that would be necessary for NIPSCO to qualify as an "eligible business" in this proceeding. The developers are EDP Renewables North America LLC and its special purpose entity RoseWater Wind Farm LLC. NIPSCO is merely an entity that proposes to invest in, and manage, a joint venture that contracts to buy from EDP Renewables North America LLC its special purpose entity RoseWater Wind Farm LLC, after the project is developed and in commercial operation. An interpretation of "undertakes a project to develop" that would include NIPSCO would sweep into the definition other parties that might contract with the developer and thus support the development, for example lenders, property owners who sell or lease their property, construction contractors and other who provide services to the development.

As to NIPSCO's joint venture entity, RoseWater Wind Generation LLC, as NIPSCO correctly states in section 13 of its Petition in the cause, RoseWater Wind Generation LLC will not be a public utility, since it will not own, operate, manage or control electric generation facilities. Accordingly RoseWater Wind Generation LLC fails to satisfy both elements the definition of "eligible businesses," and therefore cannot petition for relief under Ind. Code § 8-1-8.8-11.

Therefore, here the "eligible businesses," i.e. the entities that are undertaking a project to develop the wind farm, are EDP Renewables North America LLC and its special purpose entity RoseWater Wind Farm LLC, but neither is a petitioner seeking relief in this proceeding.

Ind. Code § 8-1-8.8-11(b) provides that "An eligible business must file an application to the commission for approval of a clean energy project under *this section*." Accordingly, it is EDP Renewables North America LLC or RoseWater Wind Farm LLC, not NIPSCO or RoseWater Wind Generation LLC, that must petition for recognition as a clean energy project for purposes of Ind. Code § 8-1-8.8-11.

Even were NIPSCO or RoseWater Wind Generation LLC a proper petitioning entity under Ind. Code § 8-1-8.8-11, they have requested no relief other than "timely recovery of costs and expenses incurred during construction and operation of [the RoseWater wind farm]." Ind. Code § 8-1-8.8-11(a)(1). However, neither of them will incur such costs and expenses for constructing and operating the project. Those costs and expenses will be incurred by EDP Renewables North America LLC or RoseWater Wind Farm LLC. The only costs NIPSCO will incur is the contract price under a PPA, and possible investments in RoseWater Wind Generation LLC. The only costs RoseWater Wind Generation LLC will incur in the cost of purchasing RoseWater Wind Farm LLC and making whatever future investments are necessary into RoseWater Wind Farm LLC to keep it solvent. Presumably, the PPA contract price RoseWater Wind Farm LLC may recover from NIPSCO is calculated to allow RoseWater Wind Farm LLC to recover its costs and expenses for constructing and operating the project plus an unknown profit, plus perhaps other amounts. There is no evidence allowing us to unbundle the contract price into costs and expenses incurred during construction and operation of the wind farm, as opposed to other elements that may be baked into that price. NIPSCO only claims the PPA contract prices are within the realm of market price for wind energy.

Third, NIPSCO seeks authority to record its interest in RoseWater Wind Generation LLC as a regulatory asset and recovery of the asset through amortization. NIPSCO also asks that the balance of that regulatory asset be included in int net original cost rate base and the value of its utility property.

6. **<u>Joint Petitioner's Case-in-Chief.</u>** [ICC does not dispute with Joint Petitioner's summary of NIPSCO's case-in-chief].

7. **<u>OUCC's Case-in-Chief.</u>** [ICC does not dispute Joint Petitioner's summary of OUCC's case-in-chief].

8. **CAC's Case-in-Chief.** [ICC does not dispute Joint Petitioner's summary of CAC's case-in-chief].

9. **IMUG's Case-in-Chief.** [ICC does not dispute Joint Petitioner's summary of IMUG's case-in-chief].

10. **NIPSCO Industrial Group's Case-in-Chief.** [ICC does not dispute Joint Petitioner's summary of NIPSCO Industrial Group's case-in-chief].

11. **LaPorte's Case-in-Chief.** [ICC does not dispute Joint Petitioner's summary of LaPorte's case-in-chief].

12. **ICC's Case-in-Chief.** ICC presented the testimony of Charles S. Griffey, a consultant providing services to the electric and natural gas industries; and Emily S. Medine, Principal in the consulting firm of Energy Ventures Analysis, Inc.

Mr. Griffey's testimony included as attachment CSG-2, his prefiled direct testimony in Cause No. 45159, as attachment CSG-3, his prefiled cross-answering testimony in Cause No. 45159, as attachment CSG-4, his prefiled direct testimony in Cause No. 45195, and as attachment CSG-5, his prefiled direct testimony in Cause No. 45196. Mr. Griffey testified that the proposed RoseWater project arose from NIPSCO's request for proposals that was issued as part of NIPSCO's 2018 update to its 2016 IRP, which resulted in NIPSCO's proposal to retire the Schahfer coal units in 2023 and the Michigan City 12 coal unit in 2028 and replace them with owned and purchased renewable energy resources. Mr. Griffey noted that NIPSCO's IRP had, as of the time of the evidentiary hearing in this matter, not yet been commented upon by Commission Staff. He further opined that NIPSCO's IRP does not support NIPSCO's decision to retire the Schahfer and Michigan City coal units in 2023 and 2028. Mr. Griffey testified that the IRP contains significant flaws, errors, and omissions and does not demonstrate that early retirement of the coal fleet in favor of building and buying renewable energy is prudent or economical for ratepayers.

Mr. Griffey testified that NIPSCO only explicitly dispatched the IRP model through 2038, and then tacked ten years on by escalating dispatch costs at inflation while continuing the drawdown of fixed capital revenue requirements. This, he said, creates a major issue when one assumes 15-year renewable PPAs and five year CCGT PPAs that end before 2038 in certain portfolios, and twenty year PPAs and thirty year owned resources in NIPSCO's Preferred Portfolio F that extend beyond 2038, because this implicitly means that in Preferred Portfolio F PTCs and ITCs are continued even after the underlying renewable PPAs have expired, while in other portfolios these PTCs and ITCs are not extended. Mr. Griffey observed that in portfolios with shorter term PPAs, these PPAs are instead replaced with generic solar units with lower capacity factors, causing replacement energy to be purchased from the market at higher prices for the differences. According to Mr. Griffey this makes the purported savings after the PPA expiration solely an artifact of NIPSCO's decision to replace 5 to 15-year PPAs with generic solar resources and to compare those to self-replicating PPAs with tax advantages and owned thirty-year resources. He testified that planners should generally not rely upon savings after ten to twenty years to justify a high cost investment today, but this is particularly true when the savings are invented by an assumption with no rational basis whatsoever.

Mr. Griffey testified that the ten-year extension from twenty to thirty years for "end effects" was required to make NIPSCO's Preferred Portfolio F, which is the only one to contain BTA projects like RoseWater, less costly than a number of other portfolios, using NIPSCO's own numbers. Mr. Griffey said that for instance, over twenty years, Portfolio 6C, which is a gas repowering at Schahfer as well as renewable PPAs is superior to Preferred Portfolio F with its wind and solar purchases under all scenarios. So are Portfolio B, which contains a 5 year CCGT PPA and 15 year wind and solar PPAs, and Portfolio C, which contains 15 year wind and solar PPAs and capacity purchases. Even Portfolio 6B, which has a greater amount of gas repowering has a lower NPVRR than Portfolio F in 2 of 4 scenarios over twenty years. Thus, according to Mr. Griffey, there is no basis in the IRP to claim that a BTA project is less costly or provides any other benefit to ratepayers compared to numerous other resources available, because NIPSCO created the savings for Portfolio F (the only one with BTA wind) out of whole cloth.

Mr. Griffey testified that even if the IRP had demonstrated that early retirement of the coal plants was prudent and economical, discovery in this case and in the related Causes 45195 and 45196 demonstrates that many of his criticisms of NIPSCO's IRP are being borne out, and therefore the RoseWater Project is not consistent with the IRP, and will in fact be more expensive than was assumed in the IRP. Mr. Griffey noted that he made similar points in his testimony in Causes 45195 and 45196, namely that (1) in NIPSCO's IRP and RFP shortlist analysis it assumed materially higher UCAP's for wind resources than it now expects for the actual wind projects it proposes to pursue; (2) NIPSCO now includes an estimate of congestion cost, while it completely ignored congestion costs in the IRP; (3) in its IRP, NIPSCO assumed 100% tax efficiency for any tax equity investment, but NIPSCO is no longer expecting tax equity investment to be 100% tax efficient; (4) NIPSCO now models the cost of the RoseWater facility as approximately 10% higher than assumed in the IRP, resulting in a material increase in the amount of capital that NIPSCO ratepayers will have to pay, that is, the expected investment for the RoseWater Project increases 44% from $62 million to $89 million, and it could go as high as $110 million if the tax equity partner contributes at the lower end of NIPSCO's expected range; and (5) the capacity factors of the proposed PPAs and owned wind resources are all lower than was assumed in the IRP, with RoseWater's expected capacity factor being 10% lower than assumed in the IRP for owned wind assets.

Mr. Griffey testified that because NIPSCO's current expectations for its actual projects are materially lower than the rosy assumptions NIPSCO embedded in its IRP, NIPSCO's preferred plan is not credible, and will cost ratepayers significantly more than numerous other alternatives. Mr. Griffey said that if NIPSCO were to use its current assumptions, it would find that continued operation of Schahfer 14/15, Michigan 12, and the conversion of Schahfer 17/18 to natural gas are likely to be cheaper alternatives than its preferred portfolio. Furthermore, he said, over any period up to twenty years, CCGT PPAs and renewable PPAs are preferable to a BTA like RoseWater.

Mr. Griffey also criticized NIPSCO's two-step IRP analysis in assuming certain replacement resources to conclude that coal plant retirement was economic, but then ignoring those resources in favor of owned resources in selecting its Preferred Portfolio F. Mr. Griffey also testified that NIPSCO made fundamental errors in its IRP analysis that biased the first-step (retirement analysis) in favor of early retirement of its coal resources and replacement with renewable resources. Mr. Griffey said those errors included: a) ignoring congestion costs and the cost of transmission to alleviate congestion; (b) assuming 100% tax efficiency from tax equity financing in creating its assumed capital costs for solar and wind resources; (c) burdening fossil fuels with an ever increasing tax on CO2 emissions beginning in 2026 in all but one scenario (and in that scenario burdening coal-fueled resources with assumed high coal prices in a down economy); (d) increasing future maintenance capital and operations and maintenance expense far in excess of the historical norm; (e) burdening its coal units with over $1 billion in environmental capital, the need for which are very uncertain; (f) not updating its assumed generic costs for future renewables once it got the results from its RFP; (g) implicitly assuming that current levels of PTCs and ITCs for replacement PPAs will be available in the future; and (h) not updating its IRP load forecasts to reflect the material change in its future load profile that could result from its proposed new industrial tariff structure. Mr. Griffey said that all of these factors biased the results. Mr. Griffey noted that in explaining its hypothesis of an inverse correlation between gas prices and coal prices NIPSCO offered no historical precedent to support its hypothesis or the possibility of coal prices rising in a down economy while simultaneously competing with lower natural gas prices.

Mr. Griffey testified that replacement Portfolio F only became NIPSCO's preferred portfolio as a result of NIPSCO's back-end plan assumptions that it applied to develop its 30-year NPV for its replacement portfolios. Mr. Griffey explained that "Back-end plan" is a term used to describe what capacity a utility assumes will be put in place in the out years of its resource planning model. He said that when NIPSCO decided to extend its planning horizon from twenty to thirty years by increasing year 2038 dispatch costs at inflation, it implicitly replicated the replacement fleet in the year 2038 through the next ten years. He noted that by designing Portfolio F to contain only twenty year or longer resources, and then extending its NPV calculation to 30-years by assumed inflation, NIPSCO effectively extended the lives of those 20-year resources through 2047, including the tax benefits of those resources. Mr. Griffey said that in the replacement portfolios, where NIPSCO assumed 5 or 15 year PPA resources that expired before 2038, NIPSCO did not extend the lives of those resources to 30 years by assuming inflation. Rather, according to Mr. Griffey, NIPSCO disadvantaged those other portfolios by assuming replacement with generic solar resources without the same tax benefits. He said, that these generic solar resources also had lower assumed capacity factors than the 5 to 15-year wind PPAs they were assumed to replace, which means that the difference is likely made up with more expensive market purchases. Mr. Griffey said that NIPSCO's claimed thirty-year savings for Portfolio F compared to other portfolios was artificially created by applying favorable back-end assumptions to Portfolio F, and applying different, unfavorable back-end assumption to the other portfolios.

Mr. Griffey presented a year-by-year comparison of the NIPSCO's projected savings which showed that Portfolio F is more costly than Portfolio C in every year until 2035, when the first 15-year wind PPA in Portfolio C expires. According to Mr. Griffey, it is only when the PPAs expire in Portfolio C and are replaced by generic owned solar resources that Portfolio F begins to show savings, and it is only by inflating the year 2038 savings for the next ten years that Portfolio F can claim an NPV advantage over Portfolio C in any scenario. Mr. Griffey further testified that had NIPSCO not artificially manufactured favorable end effects for Portfolio F and instead used 20-Year NPVs for comparison, Portfolio F could not be the preferred portfolio since it is significantly more costly that many other portfolios, including Retirement

Portfolios 5 and 6C (across all four future scenarios), Retirement Portfolio 6B (in two of the four scenarios), and Replacement Portfolios B and C (across all four scenarios).

Mr. Griffey noted that owned wind resources like the RoseWater Project only occur in Portfolio F, and urged that because Portfolio F is in fact significantly more costly to ratepayers than other portfolios, which have a variety of non-wind owned resources and different duration purchases, NIPSCO's IRP results provide no justification for the Commission to grant a CPCN for the RoseWater Project.

Mr. Griffey also testified that NIPSCO's assumption that CO2 taxes would go into effect in 3 of 4 scenarios and that coal price would be high when natural gas prices were low, is inconsistent with the reported views of MISO stakeholders who participated in MISO's 2018 transmission planning. Mr. Griffey reported that MISO only had one future scenario that restricted CO2 emissions, the Accelerated Fleet Change case, and MISO stakeholders put a 20% probability on this occurring, which Mr. Griffey said contrasts with NIPSCO's 75% likelihood of a CO2 tax in 2026. Mr. Griffey also noted that NIPSCO assumed that utilities across MISO would overbuild and therefore reserve margins would be relatively high at 17%-19%, thereby maintaining low capacity prices; however, contrary to NIPSCO, in its 2018 MTEP MISO assumed that utilities would not maintain excess capacity. Mr. Griffey testified that difference between NIPSCO's assumption and MISO's becomes important now that NIPSCO's actual renewable resources have lower expected UCAPs than NIPSCO assumed in its modeling. Therefore, according to Mr. Griffey, in order for NIPSCO to get the UCAP is assumes it needs, NIPSCO will have to buy additional capacity (which it did not include in its modeling costs). If MISO is right and NIPSCO is wrong about future capacity availability, then the cost of purchased capacity will be higher than NIPSCO assumes. Mr. Griffey calculated that at reasonably assumed future capacity prices, topping up the UCAP on the three proposed wind resources could cost customers an additional $2 million per year or an additional $20 million in NIPSCO's 30-year NPV calculation.

Mr. Griffey also testified that NIPSCO relies on current tax law to claim a need to act now based on the current expiration dates for ITCs and PTCs for solar and wind resources, yet NIPSCO ignored current law in predicting that 3 of 4 scenarios will see CO2 taxes as soon as 2026. Mr. Griffey opined that there is no basis for this discrepancy in approach, and it is purely speculative on NIPSCO's part. Mr. Griffey noted that the PTC has been extended 11 times since 1999. He criticized NIPSCO for not providing any basis for assuming a CO2 price is almost certain to be enacted for the first time ever by 2026, yet ignoring the fact that Congress has a proven track record of extending the PTC. Mr. Griffey noted that the Senate Minority Leader has recently suggested that tax incentives for renewable energy be made permanent.

Mr. Griffey opined that given present regulatory uncertainty, there is no need to act now to commit ratepayers to spend approximately $1 billion on wind resources. Instead, he said, it would be more prudent to wait to see how natural gas prices move in the future and how the cost on other technologies evolve.

Mr. Griffey noted that in 2008 in Cause 43393 NIPSCO supported its Buffalo Ridge and Barton wind PPAs based on (1) concerns about legislation limiting CO2 emissions or mandating renewable portfolio standards, and (2) the access to PTCs for those two PPAs in the face of an expiration of the PTCs, and as a result customers have paid and continue to pay excessive amounts for energy from those PPAs, particularly when including the cost of curtailment. Mr. Griffey said that while combined those PPA's are only 100 MW, they are costing customers millions of dollars annually, and would be out of the money even in NIPSCO's Aggressive Environmental Scenario with its high CO2 tax imposed in 2026. Mr. Griffey questioned whether, given this past history, NIPSCO should be asking customers to commit to many times as much wind energy premised on those same assumptions that proved faulty in 2008, namely a likelihood of CO2 taxes and no extension of PTCs. Mr. Griffey noted that it is NIPSCO's customer, and not NIPSCO, that bears the risk if NIPSCO is wrong again.

Mr. Griffey also testified that there is little certainty as to what market prices will be in 15 years and even greater uncertainty in predicting 30 years into the future. Mr. Griffey criticized NIPSCO for only looking at 30-year NPVs and ignoring the more predictable nearer term outcomes. He also testified that NIPSCO ignored the possibility of lower prices in its stochastics by choosing only to look at the 75th percentile and 95th percentile outcomes. Mr. Griffey said that customers also care about the likelihood of lower prices, i.e., the 25th percentile and the 5th percentile, and that these metrics would measure the cost and likelihood that NIPSCO's proposed expensive renewables strategy itself becomes stranded by low energy prices. Mr. Griffey testified that when NIPSCO proposes long-term, fixed contracts, customers should be even more concerned about low price outcomes than high price outcomes, becomes low price outcomes lock in losses on inflexible resources like new owned generation and PPAs, while high prices can be mitigated over time by investing at the time and in potentially lower cost new technologies. He noted that t costs of the RoseWater Project and the other wind PPAs are certainly much higher than the lower price outcome stochastics, particularly if the CO2 tax is removed in 2026.

Mr. Griffey testified that NIPSCO's strategic goal appears to be to ensure recovery of its stranded coal investment in the rate case and then build additional investment through owned-renewable resources beginning with this case. He said that because that strategy is premised on building higher cost resources with no additional benefits for customers and no apparent path to savings for customers, the Commission should reject the strategy and this CPCN.

Mr. Griffey disputed Mr. Augustine's claim that the operation and cost characteristics of RoseWater and the two proposed wind PPAs are consistent with the IRP. Mr. Griffey testified that in fact the costs of the three proposed wind resources are all higher, and the operational characteristics are worse; so much worse and so much higher, that it leaves NIPSCO's IRP approach as not credible and in need of being revisited. Mr. Griffey testified that the RoseWater Project is not only expected to be worse than what was assumed in the IRP with regard to its costs and the benefits that can be expected, but the exact amount of investment is extremely uncertain, and NIPSCO is effectively asking for a blank check from ratepayers to support the BTA.

Mr. Griffey also criticized NIPSCO's use of Levelized Cost of Energy (LCOE) calculations to justify its proposed wind projects. He testified that LCOE is not useful on a stand-alone basis because they only show the cost of the resource in question and do not account for the avoided cost, i.e., the benefit provided by the resource. Therefore, he said, LCOE calculations cannot be used to compare resources unless those resources operate in an identical time and manner. Mr. Griffey said that LCOE calculations are frequently made (particularly for talking points for uninformed audiences), but they are just as frequently misused, because LCOE calculations cannot be used to compare resources that operate at different times and in different amounts. He noted that because of this, the Energy Information Agency has begun including the levelized cost of avoided energy in addition to the levelized cost of energy in order to try and deal with the issue of operation at different times.

Mr. Griffey testified that NIPSCO makes a number of conceptual errors, and as a result makes misleading comparisons between the IRP LCOE for wind resources and the expected LCOE for the three wind resources for which it is seeking approval. Mr. Griffey said that one such error was assuming in the IRP that the wind resources would receive up to twice the amount of UCAP it is now expecting. He said that one cannot compare the LCOE of one resource to another when the benefit of capacity for those resources is so different, and here the resource assumptions in the IRP are materially different. Mr. Griffey said another such error was multiple flaws in extending the LCOE calculations through 2049 for the PPAs, which expire ten years before that. Mr. Griffey said that for the last ten years for the PPA LCOE calculation, NIPSCO adds in estimates for avoided energy and capacity costs based on forecast market prices for energy and capacity.

According to Mr. Griffey, one error is NIPSCO's attempt to extend the calculation to 2049 using UCAP assumptions that are materially higher than what NIPSCO now actually expects.

Another error was using an avoided energy price that is higher than what the wind projects actually avoid, and then escalating that price not by inflation, but by 3% real growth above inflation. Mr. Griffey said this is inconsistent with NIPSCO's assumption of no real growth in dispatch cost in its IRP, and there is no basis for its "conservative" assumption on avoided energy costs. He said this leads to a wholly meaningless set of replacement energy and capacity costs in 2040-2049, which are then compared to the owned resource over the thirty-year period. He testified that the outcome is that the PPA LCOE is driven higher relative to the owned resource LCOE, and thus, NIPSCO's LCOEs for PPAs cannot be compared to the owned resource LCOEs, and its weighted comparison to the IRP is similarly flawed.

Mr. Griffey said a third error is that NIPSCO averages the UCAP between owned resource and PPAs and then compares it to the IRP average UCAP between PPAs and owned resources. He said that in fact, owned resources have different weighting between the IRP and this case; the IRP has 54% of energy from owned resources, while in this case it is only 13%. He said that it makes no sense to average the PPA and owned resource LCOEs when the costs are so different and the weightings are so different, and doing so allows NIPSCO to act as if the LCOEs are similar with the IRP when they are not.

Mr. Griffey said that NIPSCO should have compared the LCOE between PPAs and separately between owned resources to make a meaningful comparison, and one needs to include the cost of buying the shortfall in UCAP since the IRP assumed more UCAP. Mr. Griffey performed such a comparison and testified that comparing the LCOE of the actual wind PPAs to the LCOE of the wind PPAs assumed in the IRP, that proposed wind PPAs costs are $21.8 million higher cost annually than those in the IRP, or $220 million higher NPV.

As for comparing the LCOE of the owned RoseWater resource to the assumed owned resources in the IRP, Mr. Griffey noted that LCOE calculation is complicated by material changes in assumptions NIPSCO makes. He said that in NIPSCO's LCOE calculation it, it lowered the tax equity component from 60% in the IRP of the overall investment to 54.7%, which is above the midpoint of its expected range of 45%-60% for the tax equity investment, and NIPSCO has also eliminated any ongoing capital expenditures and lowered the O&M estimate compared to the IRP by about 28%. Mr. Griffey said that given the uncertainty in the actual level of tax equity investment and in the O&M projections, he presented a range of LCOEs which showed that under all reasonable assumptions the cost for the RoseWater Project will likely be higher than what was assumed in the IRP. According to his calculations, if the tax equity investor comes in at 45%, and if O&M/maintenance capital expenditures are consistent with the IRP rather than NIPSCO new estimate for this case, and if the output degrades as typically happens for wind projects, then ratepayers would face costs that are 32% higher than what was presented in the IRP. He further noted that in the IRP owned wind projects were not the lowest cost choice in any case.

Regarding the risk that NIPSCO's proposed new industrial tariff structure could lower materially lower industrial demand and energy, Mr. Griffey testified that lower expected demand and energy creates risk for ratepayers with regard to NIPSCO's proposed wind projected, which create what are effectively a must take requirements where the ratepayers bear some risk for additional costs of congestion and curtailments. Mr. Griffey testified that even at IRP assumed cost, the high renewables portfolios were less economic than other alternatives, and when one takes into account that the actual contracts that have been negotiated are worse than the IRP results, then it is not economic for ratepayers to support these resources in the face of NIPSCO's proposed industrial market structure.

Mr. Griffey testified that according to NIPSCO's workpapers, in the test year for its rate case, the five largest customers had an average firm demand of approximately 800 Mw, and according to NIPSCO, under the proposed rate structure this could fall to as low as 50 Mw of demand. Mr. Griffey also testified that according to NIPSCO's workpapers, these five customers used over 6 million MWH annually, out of a NIPSCO total of 16 million MWH, or nearly 40%, and therefore the loss of this energy could dramatically affect NIPSCO's need to supply energy.

Mr. Griffey testified that NIPSCO is proposing to acquire nearly 2.7 million MWh at a cost of nearly $100 million annually, and over the life of the projects this is an NPV of almost $1 billion, and is almost 30% of NIPSCO's projected energy need. Mr. Griffey said this large block of effectively must take energy means that NIPSCO will be much more exposed to losses if energy prices are low than it considered in its IRP. He said that NIPSCO has not evaluated this risk, and as a result has not demonstrated the need for or prudence of such a commitment in the face of its proposed new industrial market structure.

Mr. Griffey testified that NIPSCO admits that the RoseWater and other wind projects are justified based on forecasted energy savings, and they will not provide much capacity. Mr. Griffey opined that giving blank check NIPSCO in this case (no guarantees on size of investment, operating cost, or output) based on savings calculations that are contrived and that only show savings in the tail years of a 30-year calculation is not in the public interest.

Mr. Griffey recommend that the Commission not approve the RoseWater Project.

Ms. Medine's testimony included as attachment ESM-2, her prefiled direct testimony in Cause No. 45195, and as attachment ESM-3, her prefiled direct testimony in Cause No. 45196. Ms. Medine opined that the Commission should deny NIPSCO's petition, because NIPSCO fails to demonstrate that RoseWater is needed to meet system demand, and fails to demonstrate that the RoseWater project is the lowest cost resource choice as the cost is not actually known.

Ms. Medine noted that NIPSCO repeatedly states as its justification, its Integrated Resource Plan (IRP) filed on October 31, 2018 (Cause 45160), and there are provisions in the Indiana Administration Code (IAC) which govern the submission and review of the required IRP filings. Ms. Medine said the review process for that IRP has not yet been completed, and Stakeholders await the Director's draft report, after which written comments to that draft may be submitted, after which the Director will issue a final report. Therefore, according to Ms. Medine, NIPSCO's reliance on the IRP in a proceeding to be heard in May is premature.

Ms. Medine further stated that the IRP process, including the involvement of Stakeholders and the Director, loses meaning if utilities implement their preferred outcomes before IRP analysis and review is complete, and NIPSCO abuses the IRP process by proceeding with this and the related cases—45159, 45195, and 45196 before the Director's final report, given that numerous flaws and inconsistencies in NIPSCO IRP analysis have been identified in Stakeholder comments to the IRP, in prefiled testimony in the 45159 rate case, and in prefiled testimony 45195, and 45196, and in this case.

Ms. Medine also expressed concern that a major component of NIPSCO's pending rate case (45159) is NIPSCO's proposal to alter its tariff for its largest industrial customers. She noted that under proposed Rate 831, NIPSCO's five largest customers could reduce their firm demand to just 50 MW in the aggregate, which she understands would be over a 600 MW reduction in firm load for NIPSCO. Ms. Medine testified that those five customers account for approximately 40 percent of NIPSCO's energy demand and approximately 1,200 MW of peak load plus reserves when viewed on a non-coincident, individual customer basis.

Ms. Medine noted that the fundamental purpose of integrated resource planning is to determine how a utility may most economically and reliably satisfy its future customer demand. Accordingly, she said, a reliable IRP must be based on a reasonably accurate forecast of future demand, but here NIPSCO did not attempt to model in its IRP any potential reduction in industrial load that might result from the implementation of Rate 831. Therefore, Ms. Medine testified, if Rate 831 is implemented, any reliance on NIPSCO's current IRP is problematic.

Ms. Medine further testified that suspicion, and the burden on NIPSCO to overcome it, must be especially high when, as here, implementation of the IRP involves early retirement of all existing base load generation (creating stranded cost recovery issues), and committing customers to billions of dollars of fixed contractual costs for capacity, the long-term need for which cannot be accurately assessed given the current uncertainty about NIPSCO's future load profile.

Ms. Medine testified that NIPSCO says it believes all five customers would participate in Tariff 831 but does not know to what extent, and NIPSCO assumes those five would reduce their demand to 184 MW rather than 50 MW, but it just does not know unless and until Rate 831 is implemented. She noted that NIPSCO proposes later true-up in rates after it knows.

Ms. Medine testified that the results of the IRP would probably be different with a load forecast modified to account for Rate 831 for two reasons. First, the impact on rates of smaller customers from stranded cost recovery caused by early retirement of coal assets would be even greater with a materially smaller large industrial load, perhaps driving a different strategy. She noted that NIPSCO showed a potential 32 percent increase in residential rates as a result of the new tariff which other parties' evidence indicated may understate the impact. Ms. Medine opined that impact could potentially be reduced through a different resource plan. The second reason Ms. Medine gave is that NIPSCO's resource needs will be lower if the expected load is lower, and that almost by definition, means a different IRP outcome in one way or another.

Ms. Medine said that an accurate load forecast is fundamental to a reliable IRP, and therefore if NIPSCO's proposed Rate 831 is implemented, then NIPSCO should be required to redo its IRP entirely with a proper load forecast and correct numerous other flaws before the Commission should allow NIPSCO to use its IRP as justification for any long-term adjustment in its resources.

Ms. Medine testified that NIPSCO has confirmed through its response to ICC 2-001 it did not develop a 20-year load forecast that assumes the impact of potential loss of load with the industrial tariff. Therefore, she said, NIPSCO provided no analysis of the impacts of potential lost industrial load with this petition, robust or otherwise. Instead, according to Ms. Medine, NIPSCO only provided a Challenged Economy scenario in its IRP in which it assumed flat load, but NIPSCO put a thumb on the scale in that scenario and biased the outcome in favor of early retirement of existing coal resources by assuming both high coal prices and low natural gas prices in the same scenario.

Ms. Medine noted that in 45195 and 45196, NIPSCO Witness Campbell made clear he was not involved in the IRP, and Mr. Augustine, the only witness proffered by the Company related to the IRP, confirmed he had no idea what the impact of the proposed changes to the Large Industrial Tariff was on firm load, indirectly confirming no analysis had been performed.

Ms. Medine also testified that at the hearing related to Causes 45195 and 45196, Mr. Campbell represented that those two wind projects were being added to address a capacity shortfall due to the retirement of Bailly Units 7 and 8. However, Ms. Medine noted this newly proffered justification was not discussed in the 2018 IRP and it is contrary to NIPSCO prior testimony in Cause Nos. 45159, 45195, 45196, and this cause. Ms. Medine pointed Mr. Kelly's testimony in 45159 which says "(i)n Cause No.44688 NIPSCO expanded the availability of the interruptible rate at the request of its industrial customers, and its interruptible customers allowed NIPSCO to reduce its capacity requirements by approximately 530 MWs, which ultimately led to the earlier closure of Bailly Units 7 and 8." She also pointed to Mr. Campbell's testimony in 45159 in which he states the Bailly Units 7 and 8 were retired to align "NIPSCO's supply side resources with its load obligations in MISO."

Ms. Medine also pointed to Mr. Campbell's direct testimony in this case and in 45195 and 45196 saying the primary purpose of NIPSCO's RFP "was to solicit binding bids to cover an anticipated capacity shortfall starting in 2023." Finally, she pointed to Mr. Lee's direct testimony in this case and in 45195 and 45196, saying NIPSCO's IRP "identified a potential capacity shortfall at or around 2023," and "[t]he first objective of the RFP was to solicit bids to cover NIPSCO's anticipated capacity shortfall starting in 2023." Ms. Medine noted that NIPSCO's new attempt to justify its proposed addition of 800 MW of Wind with the Bailly Station retirement was proffered for the first time in rebuttal testimony in 45195 and 45196.

Summarizing her concerns with NIPSCO's IRP, Ms. Medine testified that starting with its 2016 IRP and continuing through the 2018 IRP, NIPSCO has demonstrated a strong preference for the closure of its remaining coal fleet. She said this preference has manifested in multiple ways including the following: (1) the construction of biased scenarios (for example, the only scenario with zero carbon pricing was the Challenged Economy Scenario, which also assumes slow economic growth and inexplicably high coal prices and low natural gas prices); (2) the commodity assumptions with respect to coal and carbon taxes have been shown to disadvantage coal without justification (NIPSCO has already confirmed that its current delivered coal price is below what was assumed in the IRP); (3) the regulatory assumptions considered the worst cases including almost $0.5 billion for a non-existent regulation for NOx and ignored actual and impending regulatory changes; (4) regulatory compliance did not seek least-cost solutions or explore evolving options and strategies; (5) the methodology which considered retirement independent of replacement sequentially considered lower cost replacement resources in the retirement decisions and higher cost replacement options after the retirements were "locked in." NIPSCO failed to look at all-in costs with respect to the incorporation of renewables into its resource portfolio; (6) NIPSCO failed to determine the impact on customer rates by considering only at the NPVs, which are not a proxy for rate impact, because capital intensive scenarios will start with a large rate impact that declines over time as the capital asset is depreciated, while labor and/or fuel intensive scenarios will have a more levelized rate impact; and (7) NIPSCO inflated the "benefits" of the preferred scenario by extending the NPV analysis period (compared to the 2016 IRP) from 20 to 30 years without a justification and without actually doing a 30-year analysis.

Ms. Medine opined that NIPSCO showed no interest in finding solutions related to its existing coal fleet that would reduce customer impact. She said such efforts could have included efforts to reduce operating costs, efforts to increase the dispatch of the coal units, and efforts to identify lower cost regulatory compliance options. Ms. Medine also testified that NIPSCO failed to look at options to reduce closure costs including an offer received in the RFP process and the engagement of an investment banker to conduct a sale of the coal plants.

Ms. Medine noted that ICC Witness Griffey testified that the cost and operating assumptions that NIPSCO used to conclude its Scenario F was preferred were fraught with poor assumptions, including the assumed level of guaranteed wind capacity, the assumed level of tax equity investment, the assumed cost, the assumed capacity factor, and the assumed UCAP, which were all off-the mark in directions that favored Scenario F. Further, Ms. Medine said, NIPSCO's failure to include congestion and curtailment costs in its analysis also accounts for a significant difference in expected project costs. Ms. Medine also noted that Mr. Griffey testified that RoseWater has materially different economics than the generic wind resources selected in the IRP. Ms. Medine further noted that the expected cost of the RoseWater project is unknown and the two agreements have yet to be drafted. Therefore, RoseWater cannot be determined to be least cost or even attractive.

Ms. Medine testified that locking into a 15-year wind contract exposes NIPSCO customers to potentially higher costs if the cost of wind generation declines. She noted that the International Renewable Energy Agency (IRENA) shows a continuous decline in real dollars for onshore wind, because of (1) competitive procurement of renewable power generation, (2) increasing international competition for projects, and (3) continuous technology innovation. Ms. Medine noted that the National Energy Research Laboratory (NREL) in its 2017 review of wind generation costs also confirms the downward trend in costs, and believes that "(a)s the production tax credit ramps down and expires permanently over the next few years, it is likely that wind project weighted-average cost of capital or discount rate will be reduced as leverage increases and tax equity is replaced with cheaper debt."

Ms. Medine noted NIPSCO's own experience with its exiting wind PPAs (Buffalo Ridge and Barton) in which NIPSCO is paying above the market price for energy, and testified that if the new wind PPAs NIPSCO proposes turn out to be above market in the long term, the harm on small customers would be exacerbated should Rate 831 be approved because there would be fewer captive customers to share it. Ms. Medine noted that in seeking approval for the Buffalo Ridge and Barton wind PPAs a dozen years ago, NIPSCO pushed at least five assumptions about the future, none of which turned out to be true: (1) there would be GHG regulations, (2) there would be federal and/or state renewable portfolio standards; and (3) other renewables would experience price increases, and (4) the PTC would be unavailable after December 21, 2008, and (5) the increasing value of RECs would offset PPA costs.

Ms. Medine also disagreed with NIPSCO claim that the RoseWater project plays a role in NIPSCO achieving $500 Million in savings. Ms. Medine said the number is contrived since it compares Scenario F to itself modified to assume all solar with storage replacements instead of some wind replacements, a scenario that has never been under consideration. Ms. Medine also said the number assumes no adjustments related to the problems identified with the IRP including the artificial contrivance associated with the extension of the NPV from 20 to 30 years. Ms. Medine further noted that the wind investments provide virtually no UCAP, since. MISO states that its values for wind UCAP in Zone 6 are 7.4 percent.

Ms. Medine testified unless NIPSCO truly needs this new wind capacity, the proper comparison is not to assumed costs for assumed solar with storage, but rather to the market price, and that comparison does not show that the RoseWater project saves customers money.

Ms. Medine questioned why the developers or even NiSource would not undertake the RoseWater project as a merchant project if the economics of these projects are as rosy as NIPSCO represents. She noted that the growth of renewables is no longer in its infancy, and opined that there is no longer any reason for NIPSCO customers to subsidize their development by taking risk that the developers are unwilling to take.

Pointing to a recent decision in which the Public Utilities Commission of Texas rejected a request by Southwestern Electric Power Company for a CPCN for its ownership 70% ownership share (70 percent) of a wind project, Ms. Medine opined that the Commission should impose a requirement that utilities demonstrate customer savings, which Ms. Medine says NIPSCO has not done.

Ms. Medine recommends the Commission not approve the CPCN for RoseWater.

13. NIPSCO's Rebuttal Testimony. [ICC does not dispute with Joint Petitioner's summary of NIPSCO's rebuttal].

14. Commission Discussion and Findings. As explained in more detail below, the relief NIPSCO seeks in this proceeding is entangled with relief NIPSCO seeks in four other pending NIPSCO proceedings (45159, 45160, 45195, and 45196). Collectively in this proceeding and 45195 and 45196 NIPSCO seeks approval to begin implementing its preferred Replacement Portfolio F. According to NIPSCO Witness Augustine, "By 2023, Portfolio F added 660 MW of 20-year renewable PPA unforced capacity (UCAP), 642 MW of owned renewable UCAP, and 50 MW of short-term capacity purchases." (Exhibit 4-R, p.23, ll.2-4) 45195 and 45196 involve the addition of 700 MW (nameplate) of 20-year renewable PPA capacity. How much of the intended 660 UCAP MW that represents is a subject of debate we discuss below. This case involves the addition of 102 MW (nameplate) of owned renewable capacity. Again, how much of the intended 642 UCAP MW that represents is a subject of debate.

As detailed below, the Commission has previously approved—for NIPSCO and the other Indiana investor owned electric utilities—the type of relief NIPSCO seeks in this proceeding and 45195 and 45196, but never to the magnitude NIPSCO now seeks. NIPSCO's current resource capacity is 2,925 MW (NIPSCO Exhibit 4, Attachment 4-A, p.4). Thus 802 MW (nameplate) of proposed new wind capacity in this case and 45195 and 45196 is over 27% of NIPSCO's current capacity. This is orders of magnitude beyond any wind PPA we have previously approved.

Moreover, this is just the first step down the path of NIPSCO's implementation of its preferred Replacement Portfolio F, and before authorizing that first step we must consider whether NIPSCO has made an adequate case for going down that path. NIPSCO's preference to pursue Replacement Portfolio F rests on two pillars. First, any need for any near-term replacement portfolio is created by NIPSCO's preference to early retire all of its existing coal generation. Second, the selection of Portfolio F as the preferred replacement (instead of other possible portfolios) rests on NIPSCO's conclusion that substantial investment in owned renewable generation is preferable to a shorter term strategy that defers long-term commitments during this time of rapid change in the electric industry and markets.

A. Previous approvals of wind PPAs. Since approving Duke Energy's PPA with Benton County in 2006, the Commission has routinely approved requests by the Indiana's five investor owned electric utilities to enter into relatively small wind PPAs:

Cause	Wind Farm	Utility	MW	Term
43097	Benton County	Duke	110.7	20
43259	Benton County	SIGECO	30	20
43328	Fowler Ridge	I&M	100.4	20
43393	Buffalo Ridge	NIPSCO	50.4	15
43393	Barton	NIPSCO	50	20
43485	Hoosier	IPL	106	20
43635	Fowler Ridge II	SIGECO	50	20
43740	Lakefield	IPL	201	20
43750	Fowler Ridge II	I&M	50	20
44034	Wildcat	I&M	100	20
44362	Headwater	I&M	200	20
44444	4790 Wind Partners	Duke	10.2	20
	TOTAL		**1058.7**	

On a utility by utility basis, this amounts to:

Duke	120.9
I&M	450.4
IPL	307
NIPSCO	100.4
SIGECO	80
TOTAL	**1058.7**

In all of these prior approvals the amount of capacity was a small fraction of the utility's over all load and resources. In many of these cases, the Commission's approval was based goals of promoting the development of renewable energy and educating Indiana citizens. *See* Order in 43097 (Dec. 6, 2006) ("will help further educate Indiana citizens on the advancement and availability of renewable energy technology . . . This Indiana renewable energy project should provide valuable real-life information and quantification on the viability of Indiana commercial wind electricity generation. . . . [T]o the extent this renewable energy project proves to be successful, it should increase the likelihood of additional wind farm construction in the Midwest and particularly in Indiana."); Order in 43328 (Nov 28, 2007) ("should also demonstrate the vitality of the market for commercial wind generation. . . . [and] further educate Indiana citizens on the advancement and availability of renewable energy technology."); Order in 43393 (Jul 24, 2008) ("We have approved the purchase of wind for I&M, Vectren South, and Duke Energy, even though there was a slight premium associated with purchasing wind power in the short-run."); Order in 43485 (Oct 1, 2008) ("[I]t will also demonstrate the vitality of the market for commercial wind generation. . . . It also provides an opportunity for IPL and its customers to learn more about the use of renewable resources as a means for serving their energy needs."); Order in 43645 (Jun 17, 2009) ("[N]ot only increase the availability of emissions-free renewable energy sources in Indiana, but it will also demonstrate the vitality of the market for commercial wind generation. . . . To the extent this Renewable Energy Project proves successful, it should increase the likelihood of additional wind farm construction in Indiana."); Order in 43750 (Jan 6, 2010) ("[W]ill also demonstrate the vitality of the market for commercial wind generation.").

Finally, in Cause No. 43740 in which IPL sought to enter into a PPA for 201 MW of wind capacity (in addition to the 100 MW it already had under a prior PPA), the Commission acknowledged a need for a cost benefit analysis weighing the price premium for wind energy against other benefits—in that case resource diversity. Order in 43740, ¶8 (Jan 27, 2010) ("The necessary wind contribution is defined when a given amount is required by statute, but notably no such mandate presently exists. We must therefore refine the level of contribution in which we have sufficient confidence in the reasonable and necessary balance of price and diversity. The Commission acknowledges this need and accordingly directs its technical staff to set a course, outside this immediate proceeding, to establish a process that the Commission may utilize to comprehensively review future requests to purchase renewable energy and to determine whether an appropriate balance is being achieved."). In subsequent orders approving wind PPAs, there is no mention of any process being used to comprehensively review request to purchase renewable energy. *See* Order in 43750 (Jan 6, 2010); Order in 44034 (Sep 21, 2011); Order in 44362 (Nov 25, 2013); Order in 44444 (May 7, 2014).

In this case and 45195 and 45196 NIPSCO asks us to enter new territory. These cases are not about educating the public or gaining experience with renewable energy PPAs. In these cases NIPSCO seeks to boldly go where no Indiana utility has gone before—jettison its entire coal generation fleet, and replace it entirely with renewable resources, over 50% of which NIPSCO would own. At the same time, in Cause No. 45159 NIPSCO seeks not only to increase its rates, but also to materially change its tariff structure for its largest industrial customers to allow them access to the MISO markets to satisfy most of their electricity requirements. In addition, in Cause No. 45159 NIPSCO seeks approval to accelerate depreciation on its existing coal generation fleet, and approval in advance that whenever NIPSCO may elect to retire a coal generation resource its remaining undepreciated book value will be converted to a regulatory asset and collected from ratepayers through amortization. In Cause No. 45060 NIPSCO filed, for purposes of putting it through the Commission's IRP review process, an update to NIPSCO's 2016 IRP ("2018 IRP"). NIPSCO contends that its 2018 IRP demonstrates that it should early retire all four Schahfer coal plants in 2023, and then the remaining Michigan City coal plant in 2028. NIPSCO also contends that its 2018 IRP shows it should replace that retired generation with Replacement Portfolio F.

B. 2016 and 2018 IRPs

(1) Amount and Type of Shortfall not Identified. According to Mr. Lee, "In 2016, NIPSCO conducted an integrated resource planning process that identified a potential capacity shortfall at or around 2023.The 2016 IRP included tentative conclusions as to future resource options. In 2018, NIPSCO updated the 2016 IRP to ensure that resource planning reflected the most current outlook for key market drivers." (NIPSCO Exhibit 5, Lee, p.5, l.14 – p.6, l.3) According to Mr. Campbell, "The purpose of the RFP was to solicit binding bids to cover an anticipated capacity shortfall starting in 2023 and to obtain market-based information on the cost and performance of alternative resource options to inform and improve NIPSCO's

2018 IRP." (NIPSCO Exhibit 1, Campbell, p.25, ll.7-11). While we applaud NIPSCO's decision to conduct an all-source RFP to obtain market-based information, nothing in the evidentiary record informed the Commission about the amount of capacity shortfall NIPSCO expects in 2023.

Mr. Augustine's direct testimony said that that, "NIPSCO's preferred portfolio retires all four coal units at the R.M. Schahfer Generating Station ("Schahfer") in 2023 and retires the Michigan City Generating Station ("Michigan City") coal plant in 2028. The preferred portfolio includes the following capacity replacements over time: 125 megawatts ("MW") of energy efficiency and demand side management peak load savings by 2023, growing to 370 MW by 2038; approximately 1,100 MW of installed capacity ("ICAP") wind representing 157 MW of unforced capacity ("UCAP") entering into service in 2020 and 2021; approximately 2,100 MW of ICAP solar representing about 1,050 MW of UCAP in 2023, along with additional generic solar over the long-term; and 175 MW of ICAP solar plus storage capacity representing approximately 90 MW of UCAP in 2023." (NIPSCO Exhibit 4, Augustine, p.3, l.18 -p.4, l.10). Not only is the amount of shortfall NIPSCO is trying to fill in 2023 unspecified, we cannot tell from the record the type of shortfall (i.e. whether it is an installed capacity shortfall, a UCAP shortfall, or both).

Even if the record did inform us as to the quantity and type of capacity shortfall NIPSCO expects, the record is not convincing that Portfolio F (which consist mainly of long-term, fixed-price contracts, with no re-openers for changed circumstances, and ownership by NIPSCO of long-lived renewable assets) is the best way to address it. We recently observed, "The pre-approval of long-lived power plant investment and the concurrent regulatory assurance of that investment's recovery is, at its base, the creation of fixed costs that customers will be required to pay several years into the future, . . . Accordingly, our consideration in this and other pre-approval requests, especially in periods of seemingly quickening technological change, must not ignore the risk that any such investment may become uneconomic over the long-term." *In re Vectren*, Cause No. 45052, Final Order, p.20 (April 24, 2019). The same is true here. In this case NIPSCO seeks pre-approval of 15-year fix-price contracts, and approval to acquire indirectly a long-lived asset, with regulatory assurance of recovery of all costs. That is, at its base, the creation of fixed costs the customers will be required to pay several years into the future, in the case of the 700 MW involved in 45195 and 45196, 20 years into the future, and in the case of the 102 MW involved in this case, 30 years into the future.

In that same order we went on to say, "The inability to adjust the long-lasting nature of the supply side of the equation in the event market conditions or demand side expectations change in a lesser time horizon introduces a risk that some measure of the supply side investment may become uneconomic within its lifetime. Demand side efforts by customers as a result of the uncontroverted improving economics of customer-scale generation resources may further compound the challenge of the optimal balancing act. Reducing demand in the near term does not necessarily correspond with reduced assured supply side investment cost recovery. Because unwinding assured cost recovery should an asset become uneconomic is not a commonly employed regulatory option, it is prudent to ensure during the pre-approval process that we understand and consider the risk that customers could sometime in the future be saddled with an uneconomic investment. Outcomes that reasonably minimize such potential risk and serve to foster utility and customer flexibility in an environment of rapid technological innovation on both the utility and customer side of the meter are, therefore, a lens through which we will review Vectren South's request." *Id.*

Again, the same reasoning applies in this case.

(2) Two-Step Analysis. The evidence discloses significant controversy about the validity of NIPSCO's IRP analysis. NIPSCO's witnesses, of course, staunchly defend its IRP analysis, describing what NIPSCO did in its IRP analysis as standard practice. Nevertheless, some of the criticisms leveled by Intervenor Indiana Coal Council's expert witnesses are sources of concern.

It is undisputed that NIPSCO initially performed a separate retirement analysis comparing the cost of continuing to operate the coal units against the cost of replacement with assumed sets of replacement resources. From this step, NIPSCO concluded it should retire all its coal generation. (*See* NIPSCO Exhibit 4-R, Augustine Rebuttal, Attachment 4-R-A, p.9, ll.12-14) NIPSCO numbered these Retirement Portfolios 1 through 8 (*See* NIPSCO Exhibit 4, Attachment 4-A, p.151) "NIPSCO then performed a replacement analysis to evaluate the replacement alternatives through a more comprehensive set of parameters and scoring mechanisms." (NIPSCO Exhibit 4-R, Augustine Rebuttal, Attachment 4-R-A, p.9, ll.14-16) NIPSCO labeled these Replacement Portfolios A through F. (See NIPSCO Exhibit 4, Attachment 4-A, p.165) NIPSCO concedes Mr. Griffey's contention that the Replacement Portfolios are different from the Retirement Portfolios. Indeed, Mr. Augustine criticizes Mr. Griffey for trying to compare Retirement Portfolio 5 with Replacement Portfolio F saying it is an apples-to-oranges comparison. (NIPSCO Exhibit 4-R, Augustine Rebuttal, Attachment 4-R-A, p.10, ll.6-10)

It is also undisputed that the 2016 Director's Report challenged NIPSCO on performing the two-step analysis and NIPSCO indicated its plan to not do so in the future. Yet without justification, NIPSCO did not integrate the Director's recommendation.

Mr. Griffey characterized this two-step process as "bait and switch." (ICC Exhibit 1, Griffey, p.9, ll.5-8) Mr. Augustine defended the two-step process. However, logic is on the side of Mr. Griffey. We would not accept as sound personal financial planning the following two-step analysis of whether to buy a new car: (1) compare the cost of continuing to own and operate the current car with the cost of leasing and operating a base model economy car, finding the cost of the current car higher, and deciding to retire it; then (2) buying a new car on the basis of comparing a portfolio of luxury sedans and SUVs. The risk in such bifurcated decision making is that the cost of the actual replacement turns out to be more expensive than the cost of keeping the current car. A proper analysis requires comparing the cost of keeping the current car with the cost of the actual replacement.

Here Mr. Augustine says NIPSCO's Retirement Portfolios cannot be compared with its Replacement Portfolios. But his explanation is unsatisfactory. He says, "[T]here are different phases of the analysis that are embedded in the retirements phase and the replacements phase. So as I have explained in testimony and attachments in this proceeding, there is a multi- dimensional decision framework and scorecard that NIPSCO has used, and that is the reason that there are different objectives being measured. . . . My point is that the objectives that have been laid out in the IRP analysis in the development of the replacement portfolios included a series of diversity and duration objectives that fit into NIPSCO's scorecard." (Tr. Augustine, p.176, ll.8-15; p.177, ll.4-7) The fact that the replacement portfolios were designed to "fit into NIPSCO's scorecard," is concerning, and even if that does not imply some thumb on the scale when designing the replacement portfolios, Mr. Augustine gives no reason why the retirement portfolios could not have been evaluated using the same scorecard.

Mr. Augustine concedes that the NPV analysis and calculation was identical across all portfolios, both retirement and replacement. (Tr. Augustine, p.175, l.11 – p.176, l.5) The menu of possible new resources is the same: gas turbines, wind, solar, storage, demand response, etc. Further, Mr. Augustine does not explain why, after performing its RFP and designing its Replacement Portfolios A through F, NIPSCO could not re-run its retirement modeling using its Replacement Portfolios. We reiterate, as we have said in prior orders, that cost is but one of the deciding factors, and a utility need not always choose the least-cost option. But cost is an important factor, and to allow us to make an informed decision, NIPSCO should have presented evidence that allows the cost of continuing to operate the existing resources to be compared with the cost of the actual replacements NIPSCO proposes, not some hypothetical resources NIPSCO does not intend, and apparently never intended, to procure.

(3) Unbundling NPVs. NIPSCO's charts and tables in its IRP present us with single 30-year NPV values for its various Retirement Portfolios 1 through 8 and Replacement Portfolios A through F. (*See* NIPSCO Exhibit 4, Attachment 4-A, pp.151, 165) However, to compute those NPVs, NIPSCO calculated the assumed costs in year 1, costs in year 2, and so on through year 30. Then it discounted each year's cost back to the start and summed them to arrive at a single NPV. (Tr. Augustine, p.151, l.21 – p.154, l.10; ICC Exhibits CX-2-C and CX-3-C)

As instructive as that is in the planning exercise of IRPs, when it comes actually implementing any plan, a more time-sensitive comparison of costs is necessary, especially when, as here, we are being asked to lock customers into paying for either investments in long-lived assets as proposed in this case or in long-term, fixed-price commitments, with no re-openers for changed circumstances as NIPSCO proposed in 45195 and 45196.

Predicting the future is inherently uncertain, and the farther into the future we try to predict, the higher the margin of error becomes. Thus, we could place greater reliance on NIPSCO's projections of costs for years 1 through 5 than we could for years 25 through 30. NIPSCO's evidence did not provide us with the annual assumed cost for each portfolio, which we believe is necessary for us to make an informed decision in these cases. However, on cross-examination, ICC Exhibits CX-2-C, CX-3-C, and CX-4-C did provide us with a year by year comparison for two of the replacement portfolios, C and F.

In the Base Case, Challenged Economy, and Booming Economy scenarios, Portfolio C is materially less expensive than Portfolio F in every year through 2035. (ICC Exhibit CX-4-C) In the Aggressive Regulation scenario Portfolio C is materially less expensive in every year through 2030. For the Base Case scenario, the 20-year NPV of Portfolio C is $222,732,667 less than Portfolio F. (delta between cells C17 on ICC Exhibits CX-2-C and CX-3-C) On a 30-year NPV basis Portfolio F is only $5,973,589 less expensive than Portfolio C. (delta between cells C18 on ICC Exhibits CX-2-C and CX-3-C) In essence, by preferring Portfolio F over Portfolio C, NIPSCO is asking its customers to make a long-term bet that by losing $222,732,667 over the next twenty years, they will end up $5,973,589 better off in thirty years. The Commission doubts that is a bet most customers, if asked, would choose to make.

We understand that Portfolio's C and F are similar in that they both contain mostly renewable resources, and in both about half of the capacity is 20-year PPAs. But there are two significant differences. First, about half of Portfolio F consists of NIPSCO owned resources, like what is proposed in this case, while in Portfolio C there are no owned resources. Second, Portfolio C has significantly more short-term MISO capacity purchases. Mr. Augustine conceded that in Portfolio F the model was restrained from selecting more than 50 MW of MISO capacity purchases, and in Portfolio C the model was restrained from selecting more than 400 MW of MISO capacity purchases. (Tr. Augustine, p.158, l.8 – p.159, l.11) He conceded that had the models not been so constrained both might have selected more MISO capacity purchases as the least cost option. (*Id.*) Mr. Augustine justified so constraining the models because "least cost is not the only criteria," and "the purpose of this analysis is to evaluate and integrate a scorecard approach." (*Id.*) While we agree that least-cost is not the only criteria, it is a very important criteria, and NIPSCO's model decision making has clearly deprived both NIPSCO and the Commission of important information, namely what the least-cost portfolio would have been had the model been unconstrained, and how much less that least-cost portfolio would cost. Only with that information can reliable cost/benefit weighing of all metrics, including least-cost, be made. Without that information, NIPSCO's scorecard approach to cost/benefit weighing of multiple metrics to arrive at any preferred portfolio becomes suspect and insufficient for decision making.

Given the constraints NIPSCO imposed on its modeling there are strong reasons discussed above to prefer Portfolio C over Portfolio F. The potential benefits of Portfolio F do not appear until far in the future, and depend on assumptions made today about what technologies will exist and what they will cost in the future. As we stated earlier, "[I]n periods of seemingly quickening technological change, [we] must not ignore the risk that any such investment may become uneconomic over the long-term." *In re Vectren*, Cause No. 45052, Final Order, p.20 (April 24, 2019). However, because of the constraints NIPSCO imposed we cannot know that a portfolio of even greater MISO capacity purchases in the near-term would prove to be both less expensive and allow NIPSCO greater flexibility as the regulatory and technology horizons come into better view in the near-term.

Further, NIPSCO's failure to either use its actual replacement portfolios for its retirement analysis or design its retirement portfolios to fit into its scorecard approach prevents us from assessing whether continued operation of NIPSCO's existing coal generation beyond what NIPSCO plans might be the preferred path at this time.

Further, our decision making is inhibited by NIPSCO's decision to run its models for 20-years and but then calculate 30-year NPVs by extrapolation. Mr. Augustine conceded that the models could have been run for 30 years. (Tr. Augustine, p.170, ll.15-25) Then, he said it was unnecessary to do so because, "[T]he portfolios were designed to allow for a proper apples to apples comparison and then have an end effects analysis." (*Id.*) He further said, "So when I speak about apples to apples, there is the exact amount -- the same amount of 20-year PPAs in Portfolio C and Portfolio F that were treated identically." (Tr. Augustine, p.171, ll.10-12)

If NIPSCO believed that its analysis needed to extend 30 years or 40 years then it could have run its models for that long. However, the revelation that NIPSCO's decision to run its models for only 20 years created an external influence on its portfolio design is very concerning.

(4) Scenario and Portfolio Robustness. Commissioners in Michigan recently cautioned about IRP outcomes in which the utility's preferred outcome wins in every future scenario the utility crafted for its modeling. April 27, 2018 Order at 66, *In re DTE Elec. Co.*, Case No. in MPSC No. U-18419 (Mich. Pub. Serv. Comm'n Apr. 27, 2018), at 66 ("The Commission expects that an effective IRP should produce results, under certain scenarios, that show the preferred course of action is not actually the best option. This is how we know the IRP is testing the robustness of the preferred course of action by examining how it performs under various assumptions, even if those assumptions may seem unrealistic today.").

According to NIPSCO, its decision to acquire the wind resource proposed in this case and to enter into the PPAs involved in 45195 and 45196 is driven entirely by its IRP outcome that favors early retirement of all existing coal generation. But, ICC Exhibit CX-1 (Attachment 6-A to Mr. Augustine's Prefiled Testimony in Cause 45159) shows that NPVs for the eight Retirement Portfolios NIPSCO designed had exactly the same rank across all four of the future scenarios that NIPSCO developed (Base, Aggressive Environmental Regulation, Challenged Economy, and Booming Economy). We observe a near perfect alignment of NPVs across NIPSCO's Replacement Portfolios (*See* NIPSCO Exhibit 4, Attachment 4-A, p.165, Figure 9-21) The fact that in addition to NPV NIPSCO applied a variety of metrics to its replacement Portfolios does not prove that the portfolios and scenarios were sufficiently diverse, and as noted by the Commissioners in Michigan, the perfect alignment of NPV ranking of Retirement Portfolios across all scenarios, and the near-perfect alignment of NPV ranking of Replacement Portfolios across all scenarios, is reason for concern and perhaps investigation.

Here, whether intended or not, NIPSCO's scenario development gives the appearance of putting a thumb on the scale in favor of early retirement of its coal resources. In three of its four scenarios NIPSCO assumed near future (2026) carbon pricing. In 2008, NIPSCO cited the prospect of greenhouse gas regulation as a reason for entering into its Buffalo Ridge and Barton wind PPA. Order in 43393, p. (Jul 24, 2008) ("Another benefit of securing contractual rights to wind power today is that it will aid in compliance with future greenhouse gas ('GHG') regulation. Mr. Shambo believes utilities cannot ignore the increasing demand for GHG regulation and must develop an emission strategy that anticipates such regulation will be enacted. Moreover, investment today will more gradually reflect the additional costs resulting from GHG regulation and also avoid cost increases for renewable resources that may result after GHG regulation is passed.") It may be that carbon constraints or pricing will eventually be enacted. But given its history and current circumstances, assuming it will occur in 2026 in three out of four scenarios seems overly aggressive, and such an assumption certainly weighed against NIPSCO's existing coal generation resources as well as future portfolios with gas generation.

Then, in the only scenario in which NIPSCO did not assume carbon pricing, it introduced another assumption that disadvantaged its existing coal generation—higher coal prices coupled with low gas prices. To justify that, NIPSCO strings together a series of other assumptions. It assumes an economic downturn, which is not an unreasonable scenario to model. But it assumes because of the economic downturn no carbon pricing is enacted. Then it assumes because no carbon pricing is enacted and the weak economy, demand for natural gas falls, keeping gas prices low. Then NIPSCO makes an unprecedented leap. It assumes from all that there will be stronger coal demand causing coal prices to increase. *See* NIPSCO Exhibit 4, Attachment A-4, § 8.3.2. The problem with this string of assumptions is that NIPSCO has no historical precedent for its last leap—that coal demand and therefore coal prices would rise in a challenged economy. NIPSCO does not point to any past economic downturn when coal demand and coal prices rose. It would seem more likely that as the nation's already aged coal fleet continues to age, retirements will be forced by age alone, and demand for coal will fall whether the economy is up or down. A down economy might slow the decline, and NIPSCO's assumption of an increase in coal demand in a down economy needs more support than NIPSCO provides. Moreover, if the US economy is down, the world economy could be down also, which could depress US coal exports and put downward pressure on coal prices. We don't suggest that the last three sentences are supported by any testimony in this case. We proffer them hypothetically to emphasize that NIPSCO's rationale for assuming higher coal prices in an economic downturn is convoluted, weak, and equally unsupported by any evidence; that supports our concern that NIPSCO's development of its future scenarios was not sufficiently robust or diverse.

(5) Stochastics. We would expect NIPSCO to have performed a stochastic analysis of all the most material variables as identified by a sensitivity analysis. However, NIPSCO's IRP report indicates that a stochastics analysis was done on only a limited set of variables (commodity prices and carbon prices). (NIPSCO Exhibit 4, Attachment 4-A, §8.4).

Further, in using the outcome of its stochastic analysis, NIPSCO focused on the 75th and 95th percentiles and ignored the 25th and 5th percentiles. Apparently, NIPSCO was only concerned about high prices. But customers care about low prices too. NIPSCO's IRP analysis focuses only on the risk of high prices. But, when entering into long-term fixed-priced contracts, customers also face a risk of missing out on low future prices because they are stuck in high-priced, long-term contracts. NIPSCO's has provided no analysis of that risk that we can use to make an informed decision in these wind PPA cases.

(6) Urgency. Mr. Augustine testified on cross-examination that NIPSCO's $500 million savings claim results from comparing Replacement Portfolios F and F1 as shown in Figure 9-30 of NIPSCO's IRP. (Tr. Augustine p.150, ll.2-7). However, that is truly an apples-to-oranges comparison, because Portfolio F1 relies on new solar with storage rather than new wind resources. A proper comparison would have compared Portfolio F to a portfolio having the same amount and duration of wind generation that does not qualify for any PTC or market purchases of capacity reflecting wind's limited contribution to UCAP. NIPSCO's portfolio choices provided no such comparisons, so we have no way of knowing how much, if anything, NIPSCO customers might theoretically save or lose by NIPSCO rushing into these long-term renewable commitments in lieu of waiting a couple of years. Here again, because NIPSCO does not provide the year-by-year buildup of the costs that generate that $500 million difference, we cannot know to what extent those savings might accrue in the early years and to what extent they are predicted to accrue in later years when such predictions become more uncertain.

Finally, we express no opinion about whether or not the PTC will or will not be renewed or extended. But we note that according to the Congressional Research Bureau, the PTC has already been extended eleven times. It has been extended four times specifically for wind resources, and on six occasions it has lapsed before it was extended. (The Renewable Electricity Production Tax Credit: In Brief, November 27, 2018, table on p.4, available at https://fas.org/sgp/crs/misc/R43453.pdf (last viewed May 1, 2019)) And noted elsewhere, impending expiration of the PTC was a ground NIPSCO offered over a decade ago to support the Barton and Buffalo Ridge PPA's. In fact, the PTC did not expire then. It was extended and the rates NIPSCO customers incur under the Barton and Buffalo Ridge PPA's are significantly higher than the cost of market purchases. It is unclear why NIPSCO's assumption today is any better than the assumption made to justify those expensive contracts.

C. Load Forecast. The equation for calculating a capacity overage or shortfall is simple: capacity minus demand equals capacity overage (if positive) or capacity shortfall (if negative). Both elements of the equation—capacity and demand—must be known or estimated to do the calculation. We have already explained above that NIPSCO's evidence claims it needs the three pending wind PPAs/asset acquisitions to fill a capacity shortfall that will occur in 2023 when it retires its Schahfer coal units, but does not inform us of the magnitude or type of capacity shortfall NIPSCO expects.

What we do know, however, is that the load forecast from which NIPSCO obtained the demand element of the equation for 2023 was based on an assumption that NIPSCO's large industrial tariff structure in 2023 and beyond would be the same as it now is. What we also know is that in pending Cause No. 45159, NIPSCO seeks approval of a material change in NIPSCO's large industrial tariff structure that would allow its five largest customers to reduce their firm demand to as low as 60 MW in the aggregate,[1] "which is a potentially significant change in NIPSCO's future load profile. However, NIPSCO did not consider this proposed change, or the potential change in its load profile, in its IRP modeling." (ICC Exhibit 1, Griffey, p.5, ll.6-10)

Mr. Augustine testified that the current firm load of NIPSCO's largest industrial customers who would qualify for proposed Rate 831 is approximately 800 MW. (Tr. Augustine, p.146, ll.19-23) In Mr. Augustine's rebuttal, NIPSCO for the first time asserted the position that whatever the amount of lost industrial firm load results from Rate 831, it will be offset by about 600 MW of loss of interruptible load. (Tr. Augustine, p.182, l.23 – p. 183, l.8) That is a peak load analysis, which we acknowledge is important. However, as indicated by their relatively low UCAP values, wind resources such as proposed in this case are little relied on to satisfy peak load, because the availability of wind to power them coincident with peak is unpredictable and uncontrollable. Thus, an equally important question, especially with respect to high load factor customer like the ones who would qualify for Rate 831, is what resources does NIPSCO need most of the time to serve its load during the other 8759 hours of the year that are not the system peak? Mr. Augustine's testimony makes it appear that NIPSCO's IRP modelling may have assumed 1,200 to 1,400 MW too much load during hours other than the system peak. If the industrial load is not there, it is unlikely that take-or-pay off peak energy from wind resources will be needed to serve NIPSCO's remaining residential and commercial load that have more of a peak load shape.

[1] In a recent filing in 45159, NIPSCO and its largest industrial customers have entered into an agreement in which those customers agree to initial Tier 1 contracts under Rate 831 that in the aggregate total 177 MW. But, after the initial term of five years, nothing prevents those customers from reducing their Tier 1 contracts to 60 MW in the aggregate.

The bottom line is that NIPSCO's failure to use a long-term load forecast for its IRP modeling that is consistent with the changes in its large industrial loads that might occur were we to approve Rate 831, leaves both NIPSCO and the Commission in the dark about quantifying any capacity shortfall that might arise when NIPSCO retires any given current resource.

NIPSCO describes proposed Rate 831 as "the next step" in an evolutionary process. (Cause No. 45159, Prefiled Direct Testimony of Michael Hooper, p.13, ll.3-4) NIPSCO describes that evolutionary process as "the evolution of the market for electricity for NIPSCO as well as for its largest customers." (Cause No. 45159, Prefiled Direct Testimony of Violet Sistovaris, p.24, ll.2-3) This adds future market evolution to technological and regulatory uncertainties that presently exist. We encourage planning for the future. But, at the present time, the existence of these and other uncertainties support plans that minimize long-term contractual commitments and investments, particularly for non-peak energy, and especially those whose projected returns are negative for the initial fifteen to twenty years, and whose benefits are only projected to accrue in the far future if certain assumptions prove true.

D. Consistency with IRP. NIPSCO has claimed that the attributes of the RoseWater wind project and the wind PPAs involved in 45195 and 45196 are consistent with the assumptions it used in the IRP. However, the testimony shows (1) that NIPSCO now foresees that the UCAP for these wind projects may be materially less than what NIPSCO assumed in the IRP, (2) that expected capacity factors are all lower than NIPSCO assumed in the IRP, and (3) that the costs are higher than NIPSCO assumed in the IRP. These differences are material.

The UCAP is an indicator of contribution to satisfy NIPSCO's peak capacity obligations, both to MISO and to its customers. According to Mr. Augustine, "The preferred portfolio includes . . . approximately 1,100 MW of installed capacity ('ICAP') wind representing 157 MW of unforced capacity ('UCAP')." (Exhibit 4, p.4, ll.2-6) That is a UCAP factor of 14.27% (157 ÷ 1,100 = 0.1427). This is consistent with Mr. Griffey's testimony that in its modeling and RFP analysis NIPSCO assumed between 13.5% and 15%. (ICC Exhibit 1, p. 25, ll.8-11) Mr. Griffey also presented evidence that in Indiana (where the RoseWater project would be located) MISO assigns wind resources an average UCAP of only 7.4%. (*Id.*, p.25, l.5) This is important because had NIPSCO assumed a lower UCAP in its modeling, the model would have added another capacity resource (at some cost) to make up the difference.

The capacity factor is an indicator both of how much energy NIPSCO may expect to receive and to what extent the resource might satisfy NIPSCO's off-peak capacity obligations. If the actual capacity factor is lower than NIPSCO's modeling assumed that would lessen the value of the resource as a supplier of energy and to satisfy off-peak capacity obligations.

It goes without saying that higher actual costs than assumed costs is a negative indicator. NIPSCO did not rerun its IRP with these new costs, UCAPs, and capacity factors to determine if the RoseWater project or the PPAs in 45195 and 45196 provide net benefits to customers, nor did it demonstrate the time period over which benefits would exceed the known costs of these projects. As a result, we conclude that NIPSCO has not shown that the RoseWater project or the PPAs in 45195 and 45196 are consistent with its IRP.

E. Other Considerations. As an investor owned utility (IOU) NIPSCO is naturally inclined to prefer long-term portfolios that include owned assets on which it may earn a return. For example, ICC Exhibit CX-6-C shows, by preferring Replacement Portfolio F (which has long-term owned assets) over C (which has no owned assets), NIPSCO potentially earns hundreds of millions of dollars in additional earnings. This is not a criticism of NIPSCO or any other IOU. It is simply a fact. All other things being equal no one should object to an IOU maximizing its potential for profit. Financially healthy utilities are in the public interest. However, all other things are rarely equal. For example, NIPSCO's 30-year NPVs for Portfolios C and F make them appear relatively equal in their cost to ratepayers. But, as we have discussed above, a deeper analysis indicates that short-term Portfolio C is materially less costly and risky to ratepayers over the next fifteen to twenty years. When from a variety of potential resource portfolios, a utility seeks, as NIPSCO does, Commission authorization to implement the portfolio that potentially maximizes its profits, the utility bears a heavy burden of proof to justify that preference.

In its 2019 session the Indiana General Assembly enacted Ind. Code ch. 2-5-45 which establishes the 21st Century Energy Policy Development Task Force. That legislation directs that task force to develop recommendations for the general assembly and the governor concerning: (1) outcomes that must be achieved in order to overcome any identified challenges concerning Indiana's electric generation portfolios, along with a timeline for achieving those outcomes; (2) whether existing state policy and statutes enable state regulators to properly consider the statewide impact of changing electric generation portfolios and, if not, the best approaches to enable state regulators to consider those impacts; and (3) how to maintain reliable, resilient, and affordable electric service for all electric utility consumers, while encouraging the adoption and deployment of advanced energy technologies. A report is due no later than December 1, 2020. While nothing prohibits the Commission from approving resource retirements and acquisitions before the work of that task force is complete, the fact that such a task force will be at work in the near future and may result in changes to Indiana's regulatory regime is a factor we must consider. And, it is a factor that weighs against approving long-term contract commitments and investments before the work of that task force is complete.

In its 2019 session the Indiana General Assembly also enacted Ind. Code § 8-1-8.5-3.1 which directs the Commission to conduct a comprehensive study of the statewide impacts, both in the near term and on a long term basis, of: (1) transitions in the fuel sources and other resources used to generate electricity by electric utilities; and (2) new and emerging technologies for the generation of electricity, including the potential impact of such technologies on local grids or distribution infrastructure; on electric generation capacity, system reliability, system resilience, and the cost of electric utility service for consumers. The Commission must complete its study and issue its final report no later than July 1, 2020, so that it may be considered by the 21st Century Energy Policy Development Task Force. Again, nothing prohibits the Commission from approving resource retirements and acquisitions before that study is complete, but the fact that such a study will be performed in the near future is a factor we must consider. And, it is a factor that weighs against approving long-term contract commitments and investments before that study is complete.

F. Conclusion. We deny NIPSCO the relief it seeks because, for the reasons stated above, we conclude the evidence of record is insufficient for us to find the RoseWater project is reasonable and necessary or in the best interests of customers. In so doing, we do not intend to signal that acquisition of owned generation resources, including renewable resources, will no longer be approved. We may approve the acquisition of owned generation resources, including renewable resources, now and in the future, when the evidence is sufficient to convince us they are reasonable and necessary and in the best interests of customers. Similarly, we may approve long-term PPAs, now and in the future, when the evidence is sufficient to convince us they are reasonable and necessary and in the best interests of customers.

What we do signal by this decision is that when we are asked to approve long-lived resources with guaranteed recovery from customers over decades, we expect: (a) the evidence on need to be complete, detailed, and up to date; (b) the modeling supporting the request should reveal not just the plausible future circumstances in which the proposal is the best outcome, but the plausible future circumstances in which the proposal is not the best outcome; (c) more detail than just a single number on metrics that will accrue over long time horizons, such as cost, job gains/losses, and local economy impacts. Again, the far future is much harder to predict than the near future. Such single number metrics do not expose whether an expected overall gain is the result of relatively certain near-term losses that are offset by more speculative future gains, or vice-versa. The difference, however, might materially affect our decision making, and therefore we need sufficient evidence to know the difference.

11. Confidentiality. Joint Petitioners filed a motion for protection and nondisclosure of confidential and proprietary information on February 1, 2019. In its motion, NIPSCO states certain information redacted in the evidence is confidential, proprietary, competitively sensitive, and/or trade secrets. A Docket Entry was issued on April 25, 2019 finding such information to be preliminarily confidential and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. The confidential information was subsequently submitted under seal. The OUCC and Intervenors Indiana Coal Council, Inc. and Citizens Action Coalition of Indiana, Inc. also submitted information under seal that NIPSCO had in its February 1, 2019 motion designated as confidential, proprietary, competitively sensitive, and/or trade secrets. The Commission finds the information for which NIPSCO seeks confidential treatment is confidential trade secret information pursuant to Ind. Code§ 8-1-2-29 and Ind. Code ch. 5-14-3, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

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

1. Joint Petitioner's request for issuance to NIPSCO of a Certificate of Public Convenience and Necessity for the purchase and acquisition of a 102 MW wind farm ("the RoseWater Project") is denied.

2. Joint Petitioners' request for approval of the RoseWater Project as a Clean Energy Project under IC 8-1-8.8-11 is denied.

3. Joint Petitioners' request for approval of ratemaking and accounting treatment associated with the RoseWater Project is denied.

4. Joint Petitioners' request for authority to establish amortization rates for NIPSCO's investment in the joint venture is denied.

5. Joint Petitioners' request for approval pursuant to IC 8-1-2.5-6 of an Alternative Regulatory Plan including establishment of joint venture through which the RoseWater Project will support NIPSCO's generation fleet and the reflection in NIPSCO's net original cost rate base of its investment in joint venture is denied.

6. Joint Petitioners' request for approval of purchased power agreements through which NIPSCO will receive the energy generated by the RoseWater Project, including timely cost recovery pursuant to ind. code § 8-1-8.8-11 through NIPSCO's fuel adjustment clause is denied.

7. Joint Petitioners' request for authority to defer amortization and to accrue post-in service carrying charges on NIPSCO's investment in joint venture is denied.

8. Joint Petitioners' request, to the extent generally accepted accounting principles would treat any aspect of joint venture as debt on NIPSCO's financial statements, for approval of financing is denied.

9. Joint Petitioners' request for approval an Alternative Regulatory Plan for NIPSCO in order to facilitate the implementation of the RoseWater Project is denied.

10. Joint Petitioners' request, to the extent necessary, for issuance of an order pursuant to IC 8-1-2.5-5 declining to exercise jurisdiction over joint venture as a public utility is denied.

11. The Confidential Information submitted under seal in this Cause pursuant to Joint Petitioners' request for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure under Ind. Code§§ 8-1-2-29 and 5-14-3-4.

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

FREEMAN, HUSTON, KREVDA, OBER, AND ZIEGNER CONCUR:

APPROVED:

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

Mary M. Becerra
Secretary of the Commission

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED JOINT PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC ("NIPSCO") AND ROSEWATER WIND GENERATION LLC (THE "JOINT VENTURE") FOR (1) ISSUANCE TO NIPSCO OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE PURCHASE AND ACQUISITION OF A 102 MW WIND FARM ("THE ROSEWATER PROJECT"); (2) APPROVAL OF THE ROSEWATER PROJECT AS A CLEAN ENERGY PROJECT UNDER IND. CODE § 8-1-8.8-11; (3) APPROVAL OF RATEMAKING AND ACCOUNTING TREATMENT ASSOCIATED WITH THE ROSEWATER PROJECT; (4) AUTHORITY TO ESTABLISH AMORTIZATION RATES FOR NIPSCO'S INVESTMENT IN THE JOINT VENTURE; (5) APPROVAL PURSUANT TO IND. CODE § 8-1-2.5-6 OF AN ALTERNATIVE REGULATORY PLAN INCLUDING ESTABLISHMENT OF JOINT VENTURE THROUGH WHICH THE ROSEWATER PROJECT WILL SUPPORT NIPSCO'S GENERATION FLEET AND THE REFLECTION IN NIPSCO'S NET ORIGINAL COST RATE BASE OF ITS INVESTMENT IN JOINT VENTURE; (6) APPROVAL OF PURCHASED POWER AGREEMENTS THROUGH WHICH NIPSCO WILL RECEIVE THE ENERGY GENERATED BY THE ROSEWATER PROJECT, INCLUDING TIMELY COST RECOVERY PURSUANT TO IND. CODE § 8-1-8.8-11 THROUGH NIPSCO'S FUEL ADJUSTMENT CLAUSE; (7) AUTHORITY TO DEFER AMORTIZATION AND TO ACCRUE POST-IN SERVICE CARRYING CHARGES ON NIPSCO'S INVESTMENT IN JOINT VENTURE; (8) TO THE EXTENT GENERALLY ACCEPTED ACCOUNTING PRINCIPLES WOULD TREAT ANY ASPECT OF JOINT VENTURE AS DEBT ON NIPSCO'S FINANCIAL STATEMENTS, APPROVAL OF FINANCING; (9) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN FOR NIPSCO IN ORDER TO FACILITATE THE IMPLEMENTATION OF THE ROSEWATER PROJECT; AND (10) TO THE EXTENT NECESSARY, ISSUANCE OF AN ORDER PURSUANT TO IND. CODE § 8-1-2.5-5 DECLINING TO EXERCISE JURISDICTION OVER JOINT VENTURE AS A PUBLIC UTILITY.	)	**CAUSE NO. 45194**

ORDER OF THE COMMISSION

Presiding Officers:
James Huston, Chairman
David L. Ober, Commissioner
David Veleta, Senior Administrative Law Judge

[ICC agrees with Joint Petitioner's recitation of procedural history].

1. **<u>Notice and Commission Jurisdiction.</u>** [ICC agrees with Joint Petitioner's statement of notice and jurisdiction].

2. **<u>NIPSCO's Characteristics.</u>** [ICC agrees with Joint Petitioner's statement of NIPSCO's characteristics].

3. **<u>RoseWater's Characteristics.</u>** [ICC agrees with Joint Petitioner's statement of RoseWater's characteristics].

4. **<u>Requested Relief.</u>** [ICC agrees with Joint Petitioner's statement of relief requested].

5. **<u>Statutory Framework.</u>** Joint Petitioners' petition relies on several statutory provisions.

(1) Joint Petitioners claim that Ind. Code § 8-1-2-42(a) authorizes recovery of purchased electricity; however, on its face that statute does not provide specific authority for recovery of purchased electricity costs. Rather Section 42(a) prohibits changes in rates unless approved by the Commission on at least thirty (30) days' notice. It also prohibits a utility for filing for a general increase in its basic rates and charges more frequently than every fifteen (15) months, and creates three (3) enumerated exceptions when the Commission may approve a general increase in basic rates and charges more frequently than every fifteen (15) months. Finally, Section 42(a) excludes from the definition of "general increase in basic rates and charges" changes related solely to the cost of fuel or the cost of purchased gas or purchased electricity or adjustments in accordance with tracking provisions approved by the commission. Accordingly, all Section 42(a) provides with respect to purchased electricity is an exception that allows for increases in rates and charges more frequently than every fifteen (15) months if the change relates to the cost of purchased electricity.

We note further, that the fuel cost tracker mechanism created by Ind. Code § 8-1-2-42(d) does not provide for the tracking and recovery of all purchased electricity costs. Rather it provides for the tracking and recovery of "the cost of fuel included in the cost of purchased electricity." This could not apply to purchased wind or solar electricity since those resources have no fuel costs.

Of course, the reasonable and necessary cost of purchased electricity is a cost of operation and providing service to customers that retail electric utilities may include and recover in their rates and charges, but contrary to Joint Petitioner's contention, there is no special authority for such recovery in Ind. Code § 8-1-2-42.

(2) Joint Petitioners also seek relief under Ind. Code ch 8-1-2.5 which allows the Commission, at the request of an energy utility, to apply an alternative regulatory plan to the utility, and to decline to exercise aspects of the Commission's jurisdiction. Here, Joint Petitioners ask for several elements of alternative regulatory relief. First, Joint Petitioners ask that to the extent necessary the Commission adopt, as an alternative regulatory practice, a tracking provision to be applied in conjunction with NIPSCO's statutory quarterly fuel cost tracker, for

NIPSCO to track and recover the costs it incurs in connection with the RoseWater PPA. Ind. Code § 8-1-2.5-6(e) allows the Commission to approve Joint Petitioner's request if the Commission "finds that such action is consistent with the public interest."

(3) NIPSCO seeks a CPCN and any other necessary approval for its investment in and ownership of a membership interest in RoseWater Wind Generation LLC. As alternative regulatory relief, NIPSCO seeks to be relieved of, or to be found to have complied with, obligations imposed by Ind. Code § 8-1-8.5-5(e) for obtaining a CPCN.

Joint Petitioners also seek declination of jurisdiction over RoseWater Wind Generation LLC. We agree that RoseWater Wind Generation LLC will not own, operate, manage, or control any electric generation facilities, and therefore will not be a public utility as defined by Ind. Code § 8-1-2-1.

(4) Joint Petitioners seek a determination that the RoseWater Project is an eligible Clean Energy Project for purposes of Ind. Code § 8-1-8.8-11. NIPSCO and RoseWater Wind Generation LLC claim to be "eligible businesses" as defined in Ind. Code § 8-1-8.8-6, but they are not. There "eligible business" is defined as "an energy utility" that "undertakes a project to develop alternative energy sources, including renewable energy projects." By reason of its current ownership, operation, management, and control of electric generation facilities, NIPSCO qualifies as "an energy utility" as defined in Ind. Code § 8-1-2.5-2. But more is required to qualify as an "eligible business," namely *undertaking* "a project to develop alternative energy sources, including renewable energy projects."

In prior uncontested proceedings, the Commission has entered orders finding that a utility entering into a PPA for wind energy is an "eligible business" under Ind. Code ch. 8-1-8.8. *See, e.g.* Order in 43393 (Jul 24, 2008); Order in 44362 (Nov. 25, 2013). We note, however, that in those cases no party challenged the status of the petitioner as an "eligible business." Indeed, we expressly so stated in 43362, ¶8 ("No party challenged I&M's status as an eligible business under Chapter 8.8."). Here, Intervenor Indiana Coal Council, Inc. challenges NIPSCO's status as an "eligible business." The Indiana Supreme Court has recently clarified that statutory interpretation is the province of the courts, not the Commission. *NIPSCO Indus. Grp. v. N. Indiana Pub. Serv. Co.*, 100 N.E.3d 234, 241 (Ind. 2018), modified on reh'g (Sept. 25, 2018) ("Separation-of-powers principles do not contemplate a 'tie-goes-to-the-agency' standard for reviewing administrative decisions on questions of law. In discharging our constitutional duty, we pronounce the statutory interpretation that is best and do not acquiesce in the interpretations of others."). However, to decide in the first instance whether to grant the requested relief in this case, we must interpret the statute.

We cannot indulge the broad interpretation of the phrase "undertakes a project to develop" that would be necessary for NIPSCO to qualify as an "eligible business" in this proceeding. The developers are EDP Renewables North America LLC and its special purpose entity RoseWater Wind Farm LLC. NIPSCO is merely an entity that proposes to invest in, and manage, a joint venture that contracts to buy from EDP Renewables North America LLC its special purpose entity RoseWater Wind Farm LLC, after the project is developed and in commercial operation. An interpretation of "undertakes a project to develop" that would include NIPSCO would sweep into the definition other parties that might contract with the developer and thus support the development, for example lenders, property owners who sell or lease their property, construction contractors and other who provide services to the development.

As to NIPSCO's joint venture entity, RoseWater Wind Generation LLC, as NIPSCO correctly states in section 13 of its Petition in the cause, RoseWater Wind Generation LLC will not be a public utility, since it will not own, operate, manage or control electric generation facilities. Accordingly RoseWater Wind Generation LLC fails to satisfy both elements the definition of "eligible businesses," and therefore cannot petition for relief under Ind. Code § 8-1-8.8-11.

Therefore, here the "eligible businesses," i.e. the entities that are undertaking a project to develop the wind farm, are EDP Renewables North America LLC and its special purpose entity RoseWater Wind Farm LLC, but neither is a petitioner seeking relief in this proceeding.

Ind. Code § 8-1-8.8-11(b) provides that "An eligible business must file an application to the commission for approval of a clean energy project under *this section*." Accordingly, it is EDP Renewables North America LLC or RoseWater Wind Farm LLC, not NIPSCO or RoseWater Wind Generation LLC, that must petition for recognition as a clean energy project for purposes of Ind. Code § 8-1-8.8-11.

Even were NIPSCO or RoseWater Wind Generation LLC a proper petitioning entity under Ind. Code § 8-1-8.8-11, they have requested no relief other than "timely recovery of costs and expenses incurred during construction and operation of [the RoseWater wind farm]." Ind. Code § 8-1-8.8-11(a)(1). However, neither of them will incur such costs and expenses for constructing and operating the project. Those costs and expenses will be incurred by EDP Renewables North America LLC or RoseWater Wind Farm LLC. The only costs NIPSCO will incur is the contract price under a PPA, and possible investments in RoseWater Wind Generation LLC. The only costs RoseWater Wind Generation LLC will incur in the cost of purchasing RoseWater Wind Farm LLC and making whatever future investments are necessary into RoseWater Wind Farm LLC to keep it solvent. Presumably, the PPA contract price RoseWater Wind Farm LLC may recover from NIPSCO is calculated to allow RoseWater Wind Farm LLC to recover its costs and expenses for constructing and operating the project plus an unknown profit, plus perhaps other amounts. There is no evidence allowing us to unbundle the contract price into costs and expenses incurred during construction and operation of the wind farm, as opposed to other elements that may be baked into that price. NIPSCO only claims the PPA contract prices are within the realm of market price for wind energy.

Third, NIPSCO seeks authority to record its interest in RoseWater Wind Generation LLC as a regulatory asset and recovery of the asset through amortization. NIPSCO also asks that the balance of that regulatory asset be included in int net original cost rate base and the value of its utility property.

6. **<u>Joint Petitioner's Case-in-Chief.</u>** [ICC does not dispute with Joint Petitioner's summary of NIPSCO's case-in-chief].

7. **<u>OUCC's Case-in-Chief.</u>** [ICC does not dispute Joint Petitioner's summary of OUCC's case-in-chief].

8. **CAC's Case-in-Chief.** [ICC does not dispute Joint Petitioner's summary of CAC's case-in-chief].

9. **IMUG's Case-in-Chief.** [ICC does not dispute Joint Petitioner's summary of IMUG's case-in-chief].

10. **NIPSCO Industrial Group's Case-in-Chief.** [ICC does not dispute Joint Petitioner's summary of NIPSCO Industrial Group's case-in-chief].

11. **LaPorte's Case-in-Chief.** [ICC does not dispute Joint Petitioner's summary of LaPorte's case-in-chief].

12. **ICC's Case-in-Chief.** ICC presented the testimony of Charles S. Griffey, a consultant providing services to the electric and natural gas industries; and Emily S. Medine, Principal in the consulting firm of Energy Ventures Analysis, Inc.

Mr. Griffey's testimony included as attachment CSG-2, his prefiled direct testimony in Cause No. 45159, as attachment CSG-3, his prefiled cross-answering testimony in Cause No. 45159, as attachment CSG-4, his prefiled direct testimony in Cause No. 45195, and as attachment CSG-5, his prefiled direct testimony in Cause No. 45196. Mr. Griffey testified that the proposed RoseWater project arose from NIPSCO's request for proposals that was issued as part of NIPSCO's 2018 update to its 2016 IRP, which resulted in NIPSCO's proposal to retire the Schahfer coal units in 2023 and the Michigan City 12 coal unit in 2028 and replace them with owned and purchased renewable energy resources. Mr. Griffey noted that NIPSCO's IRP had, as of the time of the evidentiary hearing in this matter, not yet been commented upon by Commission Staff. He further opined that NIPSCO's IRP does not support NIPSCO's decision to retire the Schahfer and Michigan City coal units in 2023 and 2028. Mr. Griffey testified that the IRP contains significant flaws, errors, and omissions and does not demonstrate that early retirement of the coal fleet in favor of building and buying renewable energy is prudent or economical for ratepayers.

Mr. Griffey testified that NIPSCO only explicitly dispatched the IRP model through 2038, and then tacked ten years on by escalating dispatch costs at inflation while continuing the drawdown of fixed capital revenue requirements. This, he said, creates a major issue when one assumes 15-year renewable PPAs and five year CCGT PPAs that end before 2038 in certain portfolios, and twenty year PPAs and thirty year owned resources in NIPSCO's Preferred Portfolio F that extend beyond 2038, because this implicitly means that in Preferred Portfolio F PTCs and ITCs are continued even after the underlying renewable PPAs have expired, while in other portfolios these PTCs and ITCs are not extended. Mr. Griffey observed that in portfolios with shorter term PPAs, these PPAs are instead replaced with generic solar units with lower capacity factors, causing replacement energy to be purchased from the market at higher prices for the differences. According to Mr. Griffey this makes the purported savings after the PPA expiration solely an artifact of NIPSCO's decision to replace 5 to 15-year PPAs with generic solar resources and to compare those to self-replicating PPAs with tax advantages and owned thirty-year resources. He testified that planners should generally not rely upon savings after ten to twenty years to justify a high cost investment today, but this is particularly true when the savings are invented by an assumption with no rational basis whatsoever.

Mr. Griffey testified that the ten-year extension from twenty to thirty years for "end effects" was required to make NIPSCO's Preferred Portfolio F, which is the only one to contain BTA projects like RoseWater, less costly than a number of other portfolios, using NIPSCO's own numbers. Mr. Griffey said that for instance, over twenty years, Portfolio 6C, which is a gas repowering at Schahfer as well as renewable PPAs is superior to Preferred Portfolio F with its wind and solar purchases under all scenarios. So are Portfolio B, which contains a 5 year CCGT PPA and 15 year wind and solar PPAs, and Portfolio C, which contains 15 year wind and solar PPAs and capacity purchases. Even Portfolio 6B, which has a greater amount of gas repowering has a lower NPVRR than Portfolio F in 2 of 4 scenarios over twenty years. Thus, according to Mr. Griffey, there is no basis in the IRP to claim that a BTA project is less costly or provides any other benefit to ratepayers compared to numerous other resources available, because NIPSCO created the savings for Portfolio F (the only one with BTA wind) out of whole cloth.

Mr. Griffey testified that even if the IRP had demonstrated that early retirement of the coal plants was prudent and economical, discovery in this case and in the related Causes 45195 and 45196 demonstrates that many of his criticisms of NIPSCO's IRP are being borne out, and therefore the RoseWater Project is not consistent with the IRP, and will in fact be more expensive than was assumed in the IRP. Mr. Griffey noted that he made similar points in his testimony in Causes 45195 and 45196, namely that (1) in NIPSCO's IRP and RFP shortlist analysis it assumed materially higher UCAP's for wind resources than it now expects for the actual wind projects it proposes to pursue; (2) NIPSCO now includes an estimate of congestion cost, while it completely ignored congestion costs in the IRP; (3) in its IRP, NIPSCO assumed 100% tax efficiency for any tax equity investment, but NIPSCO is no longer expecting tax equity investment to be 100% tax efficient; (4) NIPSCO now models the cost of the RoseWater facility as approximately 10% higher than assumed in the IRP, resulting in a material increase in the amount of capital that NIPSCO ratepayers will have to pay, that is, the expected investment for the RoseWater Project increases 44% from $62 million to $89 million, and it could go as high as $110 million if the tax equity partner contributes at the lower end of NIPSCO's expected range; and (5) the capacity factors of the proposed PPAs and owned wind resources are all lower than was assumed in the IRP, with RoseWater's expected capacity factor being 10% lower than assumed in the IRP for owned wind assets.

Mr. Griffey testified that because NIPSCO's current expectations for its actual projects are materially lower than the rosy assumptions NIPSCO embedded in its IRP, NIPSCO's preferred plan is not credible, and will cost ratepayers significantly more than numerous other alternatives. Mr. Griffey said that if NIPSCO were to use its current assumptions, it would find that continued operation of Schahfer 14/15, Michigan 12, and the conversion of Schahfer 17/18 to natural gas are likely to be cheaper alternatives than its preferred portfolio. Furthermore, he said, over any period up to twenty years, CCGT PPAs and renewable PPAs are preferable to a BTA like RoseWater.

Mr. Griffey also criticized NIPSCO's two-step IRP analysis in assuming certain replacement resources to conclude that coal plant retirement was economic, but then ignoring those resources in favor of owned resources in selecting its Preferred Portfolio F. Mr. Griffey also testified that NIPSCO made fundamental errors in its IRP analysis that biased the first-step (retirement analysis) in favor of early retirement of its coal resources and replacement with renewable resources. Mr. Griffey said those errors included: a) ignoring congestion costs and the cost of transmission to alleviate congestion; (b) assuming 100% tax efficiency from tax equity financing in creating its assumed capital costs for solar and wind resources; (c) burdening fossil fuels with an ever increasing tax on CO2 emissions beginning in 2026 in all but one scenario (and in that scenario burdening coal-fueled resources with assumed high coal prices in a down economy); (d) increasing future maintenance capital and operations and maintenance expense far in excess of the historical norm; (e) burdening its coal units with over $1 billion in environmental capital, the need for which are very uncertain; (f) not updating its assumed generic costs for future renewables once it got the results from its RFP; (g) implicitly assuming that current levels of PTCs and ITCs for replacement PPAs will be available in the future; and (h) not updating its IRP load forecasts to reflect the material change in its future load profile that could result from its proposed new industrial tariff structure. Mr. Griffey said that all of these factors biased the results. Mr. Griffey noted that in explaining its hypothesis of an inverse correlation between gas prices and coal prices NIPSCO offered no historical precedent to support its hypothesis or the possibility of coal prices rising in a down economy while simultaneously competing with lower natural gas prices.

Mr. Griffey testified that replacement Portfolio F only became NIPSCO's preferred portfolio as a result of NIPSCO's back-end plan assumptions that it applied to develop its 30-year NPV for its replacement portfolios. Mr. Griffey explained that "Back-end plan" is a term used to describe what capacity a utility assumes will be put in place in the out years of its resource planning model. He said that when NIPSCO decided to extend its planning horizon from twenty to thirty years by increasing year 2038 dispatch costs at inflation, it implicitly replicated the replacement fleet in the year 2038 through the next ten years. He noted that by designing Portfolio F to contain only twenty year or longer resources, and then extending its NPV calculation to 30-years by assumed inflation, NIPSCO effectively extended the lives of those 20-year resources through 2047, including the tax benefits of those resources. Mr. Griffey said that in the replacement portfolios, where NIPSCO assumed 5 or 15 year PPA resources that expired before 2038, NIPSCO did not extend the lives of those resources to 30 years by assuming inflation. Rather, according to Mr. Griffey, NIPSCO disadvantaged those other portfolios by assuming replacement with generic solar resources without the same tax benefits. He said, that these generic solar resources also had lower assumed capacity factors than the 5 to 15-year wind PPAs they were assumed to replace, which means that the difference is likely made up with more expensive market purchases. Mr. Griffey said that NIPSCO's claimed thirty-year savings for Portfolio F compared to other portfolios was artificially created by applying favorable back-end assumptions to Portfolio F, and applying different, unfavorable back-end assumption to the other portfolios.

Mr. Griffey presented a year-by-year comparison of the NIPSCO's projected savings which showed that Portfolio F is more costly than Portfolio C in every year until 2035, when the first 15-year wind PPA in Portfolio C expires. According to Mr. Griffey, it is only when the PPAs expire in Portfolio C and are replaced by generic owned solar resources that Portfolio F begins to show savings, and it is only by inflating the year 2038 savings for the next ten years that Portfolio F can claim an NPV advantage over Portfolio C in any scenario. Mr. Griffey further testified that had NIPSCO not artificially manufactured favorable end effects for Portfolio F and instead used 20-Year NPVs for comparison, Portfolio F could not be the preferred portfolio since it is significantly more costly that many other portfolios, including Retirement

Portfolios 5 and 6C (across all four future scenarios), Retirement Portfolio 6B (in two of the four scenarios), and Replacement Portfolios B and C (across all four scenarios).

Mr. Griffey noted that owned wind resources like the RoseWater Project only occur in Portfolio F, and urged that because Portfolio F is in fact significantly more costly to ratepayers than other portfolios, which have a variety of non-wind owned resources and different duration purchases, NIPSCO's IRP results provide no justification for the Commission to grant a CPCN for the RoseWater Project.

Mr. Griffey also testified that NIPSCO's assumption that CO2 taxes would go into effect in 3 of 4 scenarios and that coal price would be high when natural gas prices were low, is inconsistent with the reported views of MISO stakeholders who participated in MISO's 2018 transmission planning. Mr. Griffey reported that MISO only had one future scenario that restricted CO2 emissions, the Accelerated Fleet Change case, and MISO stakeholders put a 20% probability on this occurring, which Mr. Griffey said contrasts with NIPSCO's 75% likelihood of a CO2 tax in 2026. Mr. Griffey also noted that NIPSCO assumed that utilities across MISO would overbuild and therefore reserve margins would be relatively high at 17%-19%, thereby maintaining low capacity prices; however, contrary to NIPSCO, in its 2018 MTEP MISO assumed that utilities would not maintain excess capacity. Mr. Griffey testified that difference between NIPSCO's assumption and MISO's becomes important now that NIPSCO's actual renewable resources have lower expected UCAPs than NIPSCO assumed in its modeling. Therefore, according to Mr. Griffey, in order for NIPSCO to get the UCAP is assumes it needs, NIPSCO will have to buy additional capacity (which it did not include in its modeling costs). If MISO is right and NIPSCO is wrong about future capacity availability, then the cost of purchased capacity will be higher than NIPSCO assumes. Mr. Griffey calculated that at reasonably assumed future capacity prices, topping up the UCAP on the three proposed wind resources could cost customers an additional $2 million per year or an additional $20 million in NIPSCO's 30-year NPV calculation.

Mr. Griffey also testified that NIPSCO relies on current tax law to claim a need to act now based on the current expiration dates for ITCs and PTCs for solar and wind resources, yet NIPSCO ignored current law in predicting that 3 of 4 scenarios will see CO2 taxes as soon as 2026. Mr. Griffey opined that there is no basis for this discrepancy in approach, and it is purely speculative on NIPSCO's part. Mr. Griffey noted that the PTC has been extended 11 times since 1999. He criticized NIPSCO for not providing any basis for assuming a CO2 price is almost certain to be enacted for the first time ever by 2026, yet ignoring the fact that Congress has a proven track record of extending the PTC. Mr. Griffey noted that the Senate Minority Leader has recently suggested that tax incentives for renewable energy be made permanent.

Mr. Griffey opined that given present regulatory uncertainty, there is no need to act now to commit ratepayers to spend approximately $1 billion on wind resources. Instead, he said, it would be more prudent to wait to see how natural gas prices move in the future and how the cost on other technologies evolve.

Mr. Griffey noted that in 2008 in Cause 43393 NIPSCO supported its Buffalo Ridge and Barton wind PPAs based on (1) concerns about legislation limiting CO2 emissions or mandating renewable portfolio standards, and (2) the access to PTCs for those two PPAs in the face of an expiration of the PTCs, and as a result customers have paid and continue to pay excessive amounts for energy from those PPAs, particularly when including the cost of curtailment. Mr. Griffey said that while combined those PPA's are only 100 MW, they are costing customers millions of dollars annually, and would be out of the money even in NIPSCO's Aggressive Environmental Scenario with its high CO2 tax imposed in 2026. Mr. Griffey questioned whether, given this past history, NIPSCO should be asking customers to commit to many times as much wind energy premised on those same assumptions that proved faulty in 2008, namely a likelihood of CO2 taxes and no extension of PTCs. Mr. Griffey noted that it is NIPSCO's customer, and not NIPSCO, that bears the risk if NIPSCO is wrong again.

Mr. Griffey also testified that there is little certainty as to what market prices will be in 15 years and even greater uncertainty in predicting 30 years into the future. Mr. Griffey criticized NIPSCO for only looking at 30-year NPVs and ignoring the more predictable nearer term outcomes. He also testified that NIPSCO ignored the possibility of lower prices in its stochastics by choosing only to look at the 75th percentile and 95th percentile outcomes. Mr. Griffey said that customers also care about the likelihood of lower prices, i.e., the 25th percentile and the 5th percentile, and that these metrics would measure the cost and likelihood that NIPSCO's proposed expensive renewables strategy itself becomes stranded by low energy prices. Mr. Griffey testified that when NIPSCO proposes long-term, fixed contracts, customers should be even more concerned about low price outcomes than high price outcomes, becomes low price outcomes lock in losses on inflexible resources like new owned generation and PPAs, while high prices can be mitigated over time by investing at the time and in potentially lower cost new technologies. He noted that t costs of the RoseWater Project and the other wind PPAs are certainly much higher than the lower price outcome stochastics, particularly if the CO2 tax is removed in 2026.

Mr. Griffey testified that NIPSCO's strategic goal appears to be to ensure recovery of its stranded coal investment in the rate case and then build additional investment through owned-renewable resources beginning with this case. He said that because that strategy is premised on building higher cost resources with no additional benefits for customers and no apparent path to savings for customers, the Commission should reject the strategy and this CPCN.

Mr. Griffey disputed Mr. Augustine's claim that the operation and cost characteristics of RoseWater and the two proposed wind PPAs are consistent with the IRP. Mr. Griffey testified that in fact the costs of the three proposed wind resources are all higher, and the operational characteristics are worse; so much worse and so much higher, that it leaves NIPSCO's IRP approach as not credible and in need of being revisited. Mr. Griffey testified that the RoseWater Project is not only expected to be worse than what was assumed in the IRP with regard to its costs and the benefits that can be expected, but the exact amount of investment is extremely uncertain, and NIPSCO is effectively asking for a blank check from ratepayers to support the BTA.

Mr. Griffey also criticized NIPSCO's use of Levelized Cost of Energy (LCOE) calculations to justify its proposed wind projects. He testified that LCOE is not useful on a stand-alone basis because they only show the cost of the resource in question and do not account for the avoided cost, i.e., the benefit provided by the resource. Therefore, he said, LCOE calculations cannot be used to compare resources unless those resources operate in an identical time and manner. Mr. Griffey said that LCOE calculations are frequently made (particularly for talking points for uninformed audiences), but they are just as frequently misused, because LCOE calculations cannot be used to compare resources that operate at different times and in different amounts. He noted that because of this, the Energy Information Agency has begun including the levelized cost of avoided energy in addition to the levelized cost of energy in order to try and deal with the issue of operation at different times.

Mr. Griffey testified that NIPSCO makes a number of conceptual errors, and as a result makes misleading comparisons between the IRP LCOE for wind resources and the expected LCOE for the three wind resources for which it is seeking approval. Mr. Griffey said that one such error was assuming in the IRP that the wind resources would receive up to twice the amount of UCAP it is now expecting. He said that one cannot compare the LCOE of one resource to another when the benefit of capacity for those resources is so different, and here the resource assumptions in the IRP are materially different. Mr. Griffey said another such error was multiple flaws in extending the LCOE calculations through 2049 for the PPAs, which expire ten years before that. Mr. Griffey said that for the last ten years for the PPA LCOE calculation, NIPSCO adds in estimates for avoided energy and capacity costs based on forecast market prices for energy and capacity.

According to Mr. Griffey, one error is NIPSCO's attempt to extend the calculation to 2049 using UCAP assumptions that are materially higher than what NIPSCO now actually expects.

Another error was using an avoided energy price that is higher than what the wind projects actually avoid, and then escalating that price not by inflation, but by 3% real growth above inflation. Mr. Griffey said this is inconsistent with NIPSCO's assumption of no real growth in dispatch cost in its IRP, and there is no basis for its "conservative" assumption on avoided energy costs. He said this leads to a wholly meaningless set of replacement energy and capacity costs in 2040-2049, which are then compared to the owned resource over the thirty-year period. He testified that the outcome is that the PPA LCOE is driven higher relative to the owned resource LCOE, and thus, NIPSCO's LCOEs for PPAs cannot be compared to the owned resource LCOEs, and its weighted comparison to the IRP is similarly flawed.

Mr. Griffey said a third error is that NIPSCO averages the UCAP between owned resource and PPAs and then compares it to the IRP average UCAP between PPAs and owned resources. He said that in fact, owned resources have different weighting between the IRP and this case; the IRP has 54% of energy from owned resources, while in this case it is only 13%. He said that it makes no sense to average the PPA and owned resource LCOEs when the costs are so different and the weightings are so different, and doing so allows NIPSCO to act as if the LCOEs are similar with the IRP when they are not.

Mr. Griffey said that NIPSCO should have compared the LCOE between PPAs and separately between owned resources to make a meaningful comparison, and one needs to include the cost of buying the shortfall in UCAP since the IRP assumed more UCAP. Mr. Griffey performed such a comparison and testified that comparing the LCOE of the actual wind PPAs to the LCOE of the wind PPAs assumed in the IRP, that proposed wind PPAs costs are \$21.8 million higher cost annually than those in the IRP, or \$220 million higher NPV.

As for comparing the LCOE of the owned RoseWater resource to the assumed owned resources in the IRP, Mr. Griffey noted that LCOE calculation is complicated by material changes in assumptions NIPSCO makes. He said that in NIPSCO's LCOE calculation it, it lowered the tax equity component from 60% in the IRP of the overall investment to 54.7%, which is above the midpoint of its expected range of 45%-60% for the tax equity investment, and NIPSCO has also eliminated any ongoing capital expenditures and lowered the O&M estimate compared to the IRP by about 28%. Mr. Griffey said that given the uncertainty in the actual level of tax equity investment and in the O&M projections, he presented a range of LCOEs which showed that under all reasonable assumptions the cost for the RoseWater Project will likely be higher than what was assumed in the IRP. According to his calculations, if the tax equity investor comes in at 45%, and if O&M/maintenance capital expenditures are consistent with the IRP rather than NIPSCO new estimate for this case, and if the output degrades as typically happens for wind projects, then ratepayers would face costs that are 32% higher than what was presented in the IRP. He further noted that in the IRP owned wind projects were not the lowest cost choice in any case.

Regarding the risk that NIPSCO's proposed new industrial tariff structure could lower materially lower industrial demand and energy, Mr. Griffey testified that lower expected demand and energy creates risk for ratepayers with regard to NIPSCO's proposed wind projected, which create what are effectively a must take requirements where the ratepayers bear some risk for additional costs of congestion and curtailments. Mr. Griffey testified that even at IRP assumed cost, the high renewables portfolios were less economic than other alternatives, and when one takes into account that the actual contracts that have been negotiated are worse than the IRP results, then it is not economic for ratepayers to support these resources in the face of NIPSCO's proposed industrial market structure.

Mr. Griffey testified that according to NIPSCO's workpapers, in the test year for its rate case, the five largest customers had an average firm demand of approximately 800 Mw, and according to NIPSCO, under the proposed rate structure this could fall to as low as 50 Mw of demand. Mr. Griffey also testified that according to NIPSCO's workpapers, these five customers used over 6 million MWH annually, out of a NIPSCO total of 16 million MWH, or nearly 40%, and therefore the loss of this energy could dramatically affect NIPSCO's need to supply energy.

Mr. Griffey testified that NIPSCO is proposing to acquire nearly 2.7 million MWh at a cost of nearly $100 million annually, and over the life of the projects this is an NPV of almost $1 billion, and is almost 30% of NIPSCO's projected energy need. Mr. Griffey said this large block of effectively must take energy means that NIPSCO will be much more exposed to losses if energy prices are low than it considered in its IRP. He said that NIPSCO has not evaluated this risk, and as a result has not demonstrated the need for or prudence of such a commitment in the face of its proposed new industrial market structure.

Mr. Griffey testified that NIPSCO admits that the RoseWater and other wind projects are justified based on forecasted energy savings, and they will not provide much capacity. Mr. Griffey opined that giving blank check NIPSCO in this case (no guarantees on size of investment, operating cost, or output) based on savings calculations that are contrived and that only show savings in the tail years of a 30-year calculation is not in the public interest.

Mr. Griffey recommend that the Commission not approve the RoseWater Project.

Ms. Medine's testimony included as attachment ESM-2, her prefiled direct testimony in Cause No. 45195, and as attachment ESM-3, her prefiled direct testimony in Cause No. 45196. Ms. Medine opined that the Commission should deny NIPSCO's petition, because NIPSCO fails to demonstrate that RoseWater is needed to meet system demand, and fails to demonstrate that the RoseWater project is the lowest cost resource choice as the cost is not actually known.

Ms. Medine noted that NIPSCO repeatedly states as its justification, its Integrated Resource Plan (IRP) filed on October 31, 2018 (Cause 45160), and there are provisions in the Indiana Administration Code (IAC) which govern the submission and review of the required IRP filings. Ms. Medine said the review process for that IRP has not yet been completed, and Stakeholders await the Director's draft report, after which written comments to that draft may be submitted, after which the Director will issue a final report. Therefore, according to Ms. Medine, NIPSCO's reliance on the IRP in a proceeding to be heard in May is premature.

Ms. Medine further stated that the IRP process, including the involvement of Stakeholders and the Director, loses meaning if utilities implement their preferred outcomes before IRP analysis and review is complete, and NIPSCO abuses the IRP process by proceeding with this and the related cases—45159, 45195, and 45196 before the Director's final report, given that numerous flaws and inconsistencies in NIPSCO IRP analysis have been identified in Stakeholder comments to the IRP, in prefiled testimony in the 45159 rate case, and in prefiled testimony 45195, and 45196, and in this case.

Ms. Medine also expressed concern that a major component of NIPSCO's pending rate case (45159) is NIPSCO's proposal to alter its tariff for its largest industrial customers. She noted that under proposed Rate 831, NIPSCO's five largest customers could reduce their firm demand to just 50 MW in the aggregate, which she understands would be over a 600 MW reduction in firm load for NIPSCO. Ms. Medine testified that those five customers account for approximately 40 percent of NIPSCO's energy demand and approximately 1,200 MW of peak load plus reserves when viewed on a non-coincident, individual customer basis.

Ms. Medine noted that the fundamental purpose of integrated resource planning is to determine how a utility may most economically and reliably satisfy its future customer demand. Accordingly, she said, a reliable IRP must be based on a reasonably accurate forecast of future demand, but here NIPSCO did not attempt to model in its IRP any potential reduction in industrial load that might result from the implementation of Rate 831. Therefore, Ms. Medine testified, if Rate 831 is implemented, any reliance on NIPSCO's current IRP is problematic.

Ms. Medine further testified that suspicion, and the burden on NIPSCO to overcome it, must be especially high when, as here, implementation of the IRP involves early retirement of all existing base load generation (creating stranded cost recovery issues), and committing customers to billions of dollars of fixed contractual costs for capacity, the long-term need for which cannot be accurately assessed given the current uncertainty about NIPSCO's future load profile.

Ms. Medine testified that NIPSCO says it believes all five customers would participate in Tariff 831 but does not know to what extent, and NIPSCO assumes those five would reduce their demand to 184 MW rather than 50 MW, but it just does not know unless and until Rate 831 is implemented. She noted that NIPSCO proposes later true-up in rates after it knows.

Ms. Medine testified that the results of the IRP would probably be different with a load forecast modified to account for Rate 831 for two reasons. First, the impact on rates of smaller customers from stranded cost recovery caused by early retirement of coal assets would be even greater with a materially smaller large industrial load, perhaps driving a different strategy. She noted that NIPSCO showed a potential 32 percent increase in residential rates as a result of the new tariff which other parties' evidence indicated may understate the impact. Ms. Medine opined that impact could potentially be reduced through a different resource plan. The second reason Ms. Medine gave is that NIPSCO's resource needs will be lower if the expected load is lower, and that almost by definition, means a different IRP outcome in one way or another.

Ms. Medine said that an accurate load forecast is fundamental to a reliable IRP, and therefore if NIPSCO's proposed Rate 831 is implemented, then NIPSCO should be required to redo its IRP entirely with a proper load forecast and correct numerous other flaws before the Commission should allow NIPSCO to use its IRP as justification for any long-term adjustment in its resources.

Ms. Medine testified that NIPSCO has confirmed through its response to ICC 2-001 it did not develop a 20-year load forecast that assumes the impact of potential loss of load with the industrial tariff. Therefore, she said, NIPSCO provided no analysis of the impacts of potential lost industrial load with this petition, robust or otherwise. Instead, according to Ms. Medine, NIPSCO only provided a Challenged Economy scenario in its IRP in which it assumed flat load, but NIPSCO put a thumb on the scale in that scenario and biased the outcome in favor of early retirement of existing coal resources by assuming both high coal prices and low natural gas prices in the same scenario.

Ms. Medine noted that in 45195 and 45196, NIPSCO Witness Campbell made clear he was not involved in the IRP, and Mr. Augustine, the only witness proffered by the Company related to the IRP, confirmed he had no idea what the impact of the proposed changes to the Large Industrial Tariff was on firm load, indirectly confirming no analysis had been performed.

Ms. Medine also testified that at the hearing related to Causes 45195 and 45196, Mr. Campbell represented that those two wind projects were being added to address a capacity shortfall due to the retirement of Bailly Units 7 and 8. However, Ms. Medine noted this newly proffered justification was not discussed in the 2018 IRP and it is contrary to NIPSCO prior testimony in Cause Nos. 45159, 45195, 45196, and this cause. Ms. Medine pointed Mr. Kelly's testimony in 45159 which says "(i)n Cause No.44688 NIPSCO expanded the availability of the interruptible rate at the request of its industrial customers, and its interruptible customers allowed NIPSCO to reduce its capacity requirements by approximately 530 MWs, which ultimately led to the earlier closure of Bailly Units 7 and 8." She also pointed to Mr. Campbell's testimony in 45159 in which he states the Bailly Units 7 and 8 were retired to align "NIPSCO's supply side resources with its load obligations in MISO."

Ms. Medine also pointed to Mr. Campbell's direct testimony in this case and in 45195 and 45196 saying the primary purpose of NIPSCO's RFP "was to solicit binding bids to cover an anticipated capacity shortfall starting in 2023." Finally, she pointed to Mr. Lee's direct testimony in this case and in 45195 and 45196, saying NIPSCO's IRP "identified a potential capacity shortfall at or around 2023," and "[t]he first objective of the RFP was to solicit bids to cover NIPSCO's anticipated capacity shortfall starting in 2023." Ms. Medine noted that NIPSCO's new attempt to justify its proposed addition of 800 MW of Wind with the Bailly Station retirement was proffered for the first time in rebuttal testimony in 45195 and 45196.

Summarizing her concerns with NIPSCO's IRP, Ms. Medine testified that starting with its 2016 IRP and continuing through the 2018 IRP, NIPSCO has demonstrated a strong preference for the closure of its remaining coal fleet. She said this preference has manifested in multiple ways including the following: (1) the construction of biased scenarios (for example, the only scenario with zero carbon pricing was the Challenged Economy Scenario, which also assumes slow economic growth and inexplicably high coal prices and low natural gas prices); (2) the commodity assumptions with respect to coal and carbon taxes have been shown to disadvantage coal without justification (NIPSCO has already confirmed that its current delivered coal price is below what was assumed in the IRP); (3) the regulatory assumptions considered the worst cases including almost $0.5 billion for a non-existent regulation for NOx and ignored actual and impending regulatory changes; (4) regulatory compliance did not seek least-cost solutions or explore evolving options and strategies; (5) the methodology which considered retirement independent of replacement sequentially considered lower cost replacement resources in the retirement decisions and higher cost replacement options after the retirements were "locked in." NIPSCO failed to look at all-in costs with respect to the incorporation of renewables into its resource portfolio; (6) NIPSCO failed to determine the impact on customer rates by considering only at the NPVs, which are not a proxy for rate impact, because capital intensive scenarios will start with a large rate impact that declines over time as the capital asset is depreciated, while labor and/or fuel intensive scenarios will have a more levelized rate impact; and (7) NIPSCO inflated the "benefits" of the preferred scenario by extending the NPV analysis period (compared to the 2016 IRP) from 20 to 30 years without a justification and without actually doing a 30-year analysis.

Ms. Medine opined that NIPSCO showed no interest in finding solutions related to its existing coal fleet that would reduce customer impact. She said such efforts could have included efforts to reduce operating costs, efforts to increase the dispatch of the coal units, and efforts to identify lower cost regulatory compliance options. Ms. Medine also testified that NIPSCO failed to look at options to reduce closure costs including an offer received in the RFP process and the engagement of an investment banker to conduct a sale of the coal plants.

Ms. Medine noted that ICC Witness Griffey testified that the cost and operating assumptions that NIPSCO used to conclude its Scenario F was preferred were fraught with poor assumptions, including the assumed level of guaranteed wind capacity, the assumed level of tax equity investment, the assumed cost, the assumed capacity factor, and the assumed UCAP, which were all off-the mark in directions that favored Scenario F. Further, Ms. Medine said, NIPSCO's failure to include congestion and curtailment costs in its analysis also accounts for a significant difference in expected project costs. Ms. Medine also noted that Mr. Griffey testified that RoseWater has materially different economics than the generic wind resources selected in the IRP. Ms. Medine further noted that the expected cost of the RoseWater project is unknown and the two agreements have yet to be drafted. Therefore, RoseWater cannot be determined to be least cost or even attractive.

Ms. Medine testified that locking into a 15-year wind contract exposes NIPSCO customers to potentially higher costs if the cost of wind generation declines. She noted that the International Renewable Energy Agency (IRENA) shows a continuous decline in real dollars for onshore wind, because of (1) competitive procurement of renewable power generation, (2) increasing international competition for projects, and (3) continuous technology innovation. Ms. Medine noted that the National Energy Research Laboratory (NREL) in its 2017 review of wind generation costs also confirms the downward trend in costs, and believes that "(a)s the production tax credit ramps down and expires permanently over the next few years, it is likely that wind project weighted-average cost of capital or discount rate will be reduced as leverage increases and tax equity is replaced with cheaper debt."

Ms. Medine noted NIPSCO's own experience with its exiting wind PPAs (Buffalo Ridge and Barton) in which NIPSCO is paying above the market price for energy, and testified that if the new wind PPAs NIPSCO proposes turn out to be above market in the long term, the harm on small customers would be exacerbated should Rate 831 be approved because there would be fewer captive customers to share it. Ms. Medine noted that in seeking approval for the Buffalo Ridge and Barton wind PPAs a dozen years ago, NIPSCO pushed at least five assumptions about the future, none of which turned out to be true: (1) there would be GHG regulations, (2) there would be federal and/or state renewable portfolio standards; and (3) other renewables would experience price increases, and (4) the PTC would be unavailable after December 21, 2008, and (5) the increasing value of RECs would offset PPA costs.

Ms. Medine also disagreed with NIPSCO claim that the RoseWater project plays a role in NIPSCO achieving $500 Million in savings. Ms. Medine said the number is contrived since it compares Scenario F to itself modified to assume all solar with storage replacements instead of some wind replacements, a scenario that has never been under consideration. Ms. Medine also said the number assumes no adjustments related to the problems identified with the IRP including the artificial contrivance associated with the extension of the NPV from 20 to 30 years. Ms. Medine further noted that the wind investments provide virtually no UCAP, since. MISO states that its values for wind UCAP in Zone 6 are 7.4 percent.

Ms. Medine testified unless NIPSCO truly needs this new wind capacity, the proper comparison is not to assumed costs for assumed solar with storage, but rather to the market price, and that comparison does not show that the RoseWater project saves customers money.

Ms. Medine questioned why the developers or even NiSource would not undertake the RoseWater project as a merchant project if the economics of these projects are as rosy as NIPSCO represents. She noted that the growth of renewables is no longer in its infancy, and opined that there is no longer any reason for NIPSCO customers to subsidize their development by taking risk that the developers are unwilling to take.

Pointing to a recent decision in which the Public Utilities Commission of Texas rejected a request by Southwestern Electric Power Company for a CPCN for its ownership 70% ownership share (70 percent) of a wind project, Ms. Medine opined that the Commission should impose a requirement that utilities demonstrate customer savings, which Ms. Medine says NIPSCO has not done.

Ms. Medine recommends the Commission not approve the CPCN for RoseWater.

13. NIPSCO's Rebuttal Testimony. [ICC does not dispute with Joint Petitioner's summary of NIPSCO's rebuttal].

14. Commission Discussion and Findings. As explained in more detail below, the relief NIPSCO seeks in this proceeding is entangled with relief NIPSCO seeks in four other pending NIPSCO proceedings (45159, 45160, 45195, and 45196). Collectively in this proceeding and 45195 and 45196 NIPSCO seeks approval to begin implementing its preferred Replacement Portfolio F. According to NIPSCO Witness Augustine, "By 2023, Portfolio F added 660 MW of 20-year renewable PPA unforced capacity (UCAP), 642 MW of owned renewable UCAP, and 50 MW of short-term capacity purchases." (Exhibit 4-R, p.23, ll.2-4) 45195 and 45196 involve the addition of 700 MW (nameplate) of 20-year renewable PPA capacity. How much of the intended 660 UCAP MW that represents is a subject of debate we discuss below. This case involves the addition of 102 MW (nameplate) of owned renewable capacity. Again, how much of the intended 642 UCAP MW that represents is a subject of debate.

As detailed below, the Commission has previously approved—for NIPSCO and the other Indiana investor owned electric utilities—the type of relief NIPSCO seeks in this proceeding and 45195 and 45196, but never to the magnitude NIPSCO now seeks. NIPSCO's current resource capacity is 2,925 MW (NIPSCO Exhibit 4, Attachment 4-A, p.4). Thus 802 MW (nameplate) of proposed new wind capacity in this case and 45195 and 45196 is over 27% of NIPSCO's current capacity. This is orders of magnitude beyond any wind PPA we have previously approved.

Moreover, this is just the first step down the path of NIPSCO's implementation of its preferred Replacement Portfolio F, and before authorizing that first step we must consider whether NIPSCO has made an adequate case for going down that path. NIPSCO's preference to pursue Replacement Portfolio F rests on two pillars. First, any need for any near-term replacement portfolio is created by NIPSCO's preference to early retire all of its existing coal generation. Second, the selection of Portfolio F as the preferred replacement (instead of other possible portfolios) rests on NIPSCO's conclusion that substantial investment in owned renewable generation is preferable to a shorter term strategy that defers long-term commitments during this time of rapid change in the electric industry and markets.

A. Previous approvals of wind PPAs. Since approving Duke Energy's PPA with Benton County in 2006, the Commission has routinely approved requests by the Indiana's five investor owned electric utilities to enter into relatively small wind PPAs:

Cause	Wind Farm	Utility	MW	Term
43097	Benton County	Duke	110.7	20
43259	Benton County	SIGECO	30	20
43328	Fowler Ridge	I&M	100.4	20
43393	Buffalo Ridge	NIPSCO	50.4	15
43393	Barton	NIPSCO	50	20
43485	Hoosier	IPL	106	20
43635	Fowler Ridge II	SIGECO	50	20
43740	Lakefield	IPL	201	20
43750	Fowler Ridge II	I&M	50	20
44034	Wildcat	I&M	100	20
44362	Headwater	I&M	200	20
44444	4790 Wind Partners	Duke	10.2	20
	TOTAL		**1058.7**	

On a utility by utility basis, this amounts to:

Duke	120.9
I&M	450.4
IPL	307
NIPSCO	100.4
SIGECO	80
TOTAL	**1058.7**

In all of these prior approvals the amount of capacity was a small fraction of the utility's over all load and resources. In many of these cases, the Commission's approval was based goals of promoting the development of renewable energy and educating Indiana citizens. *See* Order in 43097 (Dec. 6, 2006) ("will help further educate Indiana citizens on the advancement and availability of renewable energy technology . . . This Indiana renewable energy project should provide valuable real-life information and quantification on the viability of Indiana commercial wind electricity generation. . . . [T]o the extent this renewable energy project proves to be successful, it should increase the likelihood of additional wind farm construction in the Midwest and particularly in Indiana."); Order in 43328 (Nov 28, 2007) ("should also demonstrate the vitality of the market for commercial wind generation. . . . [and] further educate Indiana citizens on the advancement and availability of renewable energy technology."); Order in 43393 (Jul 24, 2008) ("We have approved the purchase of wind for I&M, Vectren South, and Duke Energy, even though there was a slight premium associated with purchasing wind power in the short-run."); Order in 43485 (Oct 1, 2008) ("[I]t will also demonstrate the vitality of the market for commercial wind generation. . . . It also provides an opportunity for IPL and its customers to learn more about the use of renewable resources as a means for serving their energy needs."); Order in 43645 (Jun 17, 2009) ("[N]ot only increase the availability of emissions-free renewable energy sources in Indiana, but it will also demonstrate the vitality of the market for commercial wind generation. . . . To the extent this Renewable Energy Project proves successful, it should increase the likelihood of additional wind farm construction in Indiana."); Order in 43750 (Jan 6, 2010) ("[W]ill also demonstrate the vitality of the market for commercial wind generation.").

Finally, in Cause No. 43740 in which IPL sought to enter into a PPA for 201 MW of wind capacity (in addition to the 100 MW it already had under a prior PPA), the Commission acknowledged a need for a cost benefit analysis weighing the price premium for wind energy against other benefits—in that case resource diversity. Order in 43740, ¶8 (Jan 27, 2010) ("The necessary wind contribution is defined when a given amount is required by statute, but notably no such mandate presently exists. We must therefore refine the level of contribution in which we have sufficient confidence in the reasonable and necessary balance of price and diversity. The Commission acknowledges this need and accordingly directs its technical staff to set a course, outside this immediate proceeding, to establish a process that the Commission may utilize to comprehensively review future requests to purchase renewable energy and to determine whether an appropriate balance is being achieved."). In subsequent orders approving wind PPAs, there is no mention of any process being used to comprehensively review request to purchase renewable energy. *See* Order in 43750 (Jan 6, 2010); Order in 44034 (Sep 21, 2011); Order in 44362 (Nov 25, 2013); Order in 44444 (May 7, 2014).

In this case and 45195 and 45196 NIPSCO asks us to enter new territory. These cases are not about educating the public or gaining experience with renewable energy PPAs. In these cases NIPSCO seeks to boldly go where no Indiana utility has gone before—jettison its entire coal generation fleet, and replace it entirely with renewable resources, over 50% of which NIPSCO would own. At the same time, in Cause No. 45159 NIPSCO seeks not only to increase its rates, but also to materially change its tariff structure for its largest industrial customers to allow them access to the MISO markets to satisfy most of their electricity requirements. In addition, in Cause No. 45159 NIPSCO seeks approval to accelerate depreciation on its existing coal generation fleet, and approval in advance that whenever NIPSCO may elect to retire a coal generation resource its remaining undepreciated book value will be converted to a regulatory asset and collected from ratepayers through amortization. In Cause No. 45060 NIPSCO filed, for purposes of putting it through the Commission's IRP review process, an update to NIPSCO's 2016 IRP ("2018 IRP"). NIPSCO contends that its 2018 IRP demonstrates that it should early retire all four Schahfer coal plants in 2023, and then the remaining Michigan City coal plant in 2028. NIPSCO also contends that its 2018 IRP shows it should replace that retired generation with Replacement Portfolio F.

B. 2016 and 2018 IRPs

(1) Amount and Type of Shortfall not Identified. According to Mr. Lee, "In 2016, NIPSCO conducted an integrated resource planning process that identified a potential capacity shortfall at or around 2023.The 2016 IRP included tentative conclusions as to future resource options. In 2018, NIPSCO updated the 2016 IRP to ensure that resource planning reflected the most current outlook for key market drivers." (NIPSCO Exhibit 5, Lee, p.5, l.14 – p.6, l.3) According to Mr. Campbell, "The purpose of the RFP was to solicit binding bids to cover an anticipated capacity shortfall starting in 2023 and to obtain market-based information on the cost and performance of alternative resource options to inform and improve NIPSCO's

2018 IRP." (NIPSCO Exhibit 1, Campbell, p.25, ll.7-11). While we applaud NIPSCO's decision to conduct an all-source RFP to obtain market-based information, nothing in the evidentiary record informed the Commission about the amount of capacity shortfall NIPSCO expects in 2023.

Mr. Augustine's direct testimony said that that, "NIPSCO's preferred portfolio retires all four coal units at the R.M. Schahfer Generating Station ("Schahfer") in 2023 and retires the Michigan City Generating Station ("Michigan City") coal plant in 2028. The preferred portfolio includes the following capacity replacements over time: 125 megawatts ("MW") of energy efficiency and demand side management peak load savings by 2023, growing to 370 MW by 2038; approximately 1,100 MW of installed capacity ("ICAP") wind representing 157 MW of unforced capacity ("UCAP") entering into service in 2020 and 2021; approximately 2,100 MW of ICAP solar representing about 1,050 MW of UCAP in 2023, along with additional generic solar over the long-term; and 175 MW of ICAP solar plus storage capacity representing approximately 90 MW of UCAP in 2023." (NIPSCO Exhibit 4, Augustine, p.3, l.18 -p.4, l.10). Not only is the amount of shortfall NIPSCO is trying to fill in 2023 unspecified, we cannot tell from the record the type of shortfall (i.e. whether it is an installed capacity shortfall, a UCAP shortfall, or both).

Even if the record did inform us as to the quantity and type of capacity shortfall NIPSCO expects, the record is not convincing that Portfolio F (which consist mainly of long-term, fixed-price contracts, with no re-openers for changed circumstances, and ownership by NIPSCO of long-lived renewable assets) is the best way to address it. We recently observed, "The pre-approval of long-lived power plant investment and the concurrent regulatory assurance of that investment's recovery is, at its base, the creation of fixed costs that customers will be required to pay several years into the future, . . . Accordingly, our consideration in this and other pre-approval requests, especially in periods of seemingly quickening technological change, must not ignore the risk that any such investment may become uneconomic over the long-term." *In re Vectren*, Cause No. 45052, Final Order, p.20 (April 24, 2019). The same is true here. In this case NIPSCO seeks pre-approval of 15-year fix-price contracts, and approval to acquire indirectly a long-lived asset, with regulatory assurance of recovery of all costs. That is, at its base, the creation of fixed costs the customers will be required to pay several years into the future, in the case of the 700 MW involved in 45195 and 45196, 20 years into the future, and in the case of the 102 MW involved in this case, 30 years into the future.

In that same order we went on to say, "The inability to adjust the long-lasting nature of the supply side of the equation in the event market conditions or demand side expectations change in a lesser time horizon introduces a risk that some measure of the supply side investment may become uneconomic within its lifetime. Demand side efforts by customers as a result of the uncontroverted improving economics of customer-scale generation resources may further compound the challenge of the optimal balancing act. Reducing demand in the near term does not necessarily correspond with reduced assured supply side investment cost recovery. Because unwinding assured cost recovery should an asset become uneconomic is not a commonly employed regulatory option, it is prudent to ensure during the pre-approval process that we understand and consider the risk that customers could sometime in the future be saddled with an uneconomic investment. Outcomes that reasonably minimize such potential risk and serve to foster utility and customer flexibility in an environment of rapid technological innovation on both the utility and customer side of the meter are, therefore, a lens through which we will review Vectren South's request.” *Id.*

Again, the same reasoning applies in this case.

(2) Two-Step Analysis. The evidence discloses significant controversy about the validity of NIPSCO’s IRP analysis. NIPSCO’s witnesses, of course, staunchly defend its IRP analysis, describing what NIPSCO did in its IRP analysis as standard practice. Nevertheless, some of the criticisms leveled by Intervenor Indiana Coal Council’s expert witnesses are sources of concern.

It is undisputed that NIPSCO initially performed a separate retirement analysis comparing the cost of continuing to operate the coal units against the cost of replacement with assumed sets of replacement resources. From this step, NIPSCO concluded it should retire all its coal generation. (*See* NIPSCO Exhibit 4-R, Augustine Rebuttal, Attachment 4-R-A, p.9, ll.12-14) NIPSCO numbered these Retirement Portfolios 1 through 8 (*See* NIPSCO Exhibit 4, Attachment 4-A, p.151) “NIPSCO then performed a replacement analysis to evaluate the replacement alternatives through a more comprehensive set of parameters and scoring mechanisms.” (NIPSCO Exhibit 4-R, Augustine Rebuttal, Attachment 4-R-A, p.9, ll.14-16) NIPSCO labeled these Replacement Portfolios A through F. (See NIPSCO Exhibit 4, Attachment 4-A, p.165) NIPSCO concedes Mr. Griffey’s contention that the Replacement Portfolios are different from the Retirement Portfolios. Indeed, Mr. Augustine criticizes Mr. Griffey for trying to compare Retirement Portfolio 5 with Replacement Portfolio F saying it is an apples-to-oranges comparison. (NIPSCO Exhibit 4-R, Augustine Rebuttal, Attachment 4-R-A, p.10, ll.6-10)

It is also undisputed that the 2016 Director’s Report challenged NIPSCO on performing the two-step analysis and NIPSCO indicated its plan to not do so in the future. Yet without justification, NIPSCO did not integrate the Director’s recommendation.

Mr. Griffey characterized this two-step process as “bait and switch.” (ICC Exhibit 1, Griffey, p.9, ll.5-8) Mr. Augustine defended the two-step process. However, logic is on the side of Mr. Griffey. We would not accept as sound personal financial planning the following two-step analysis of whether to buy a new car: (1) compare the cost of continuing to own and operate the current car with the cost of leasing and operating a base model economy car, finding the cost of the current car higher, and deciding to retire it; then (2) buying a new car on the basis of comparing a portfolio of luxury sedans and SUVs. The risk in such bifurcated decision making is that the cost of the actual replacement turns out to be more expensive than the cost of keeping the current car. A proper analysis requires comparing the cost of keeping the current car with the cost of the actual replacement.

Here Mr. Augustine says NIPSCO’s Retirement Portfolios cannot be compared with its Replacement Portfolios. But his explanation is unsatisfactory. He says, “[T]here are different phases of the analysis that are embedded in the retirements phase and the replacements phase. So as I have explained in testimony and attachments in this proceeding, there is a multi- dimensional decision framework and scorecard that NIPSCO has used, and that is the reason that there are different objectives being measured. . . . My point is that the objectives that have been laid out in the IRP analysis in the development of the replacement portfolios included a series of diversity and duration objectives that fit into NIPSCO's scorecard." (Tr. Augustine, p.176, ll.8-15; p.177, ll.4-7) The fact that the replacement portfolios were designed to "fit into NIPSCO's scorecard," is concerning, and even if that does not imply some thumb on the scale when designing the replacement portfolios, Mr. Augustine gives no reason why the retirement portfolios could not have been evaluated using the same scorecard.

Mr. Augustine concedes that the NPV analysis and calculation was identical across all portfolios, both retirement and replacement. (Tr. Augustine, p.175, l.11 – p.176, l.5) The menu of possible new resources is the same: gas turbines, wind, solar, storage, demand response, etc. Further, Mr. Augustine does not explain why, after performing its RFP and designing its Replacement Portfolios A through F, NIPSCO could not re-run its retirement modeling using its Replacement Portfolios. We reiterate, as we have said in prior orders, that cost is but one of the deciding factors, and a utility need not always choose the least-cost option. But cost is an important factor, and to allow us to make an informed decision, NIPSCO should have presented evidence that allows the cost of continuing to operate the existing resources to be compared with the cost of the actual replacements NIPSCO proposes, not some hypothetical resources NIPSCO does not intend, and apparently never intended, to procure.

(3) Unbundling NPVs. NIPSCO's charts and tables in its IRP present us with single 30-year NPV values for its various Retirement Portfolios 1 through 8 and Replacement Portfolios A through F. (*See* NIPSCO Exhibit 4, Attachment 4-A, pp.151, 165) However, to compute those NPVs, NIPSCO calculated the assumed costs in year 1, costs in year 2, and so on through year 30. Then it discounted each year's cost back to the start and summed them to arrive at a single NPV. (Tr. Augustine, p.151, l.21 – p.154, l.10; ICC Exhibits CX-2-C and CX-3-C)

As instructive as that is in the planning exercise of IRPs, when it comes actually implementing any plan, a more time-sensitive comparison of costs is necessary, especially when, as here, we are being asked to lock customers into paying for either investments in long-lived assets as proposed in this case or in long-term, fixed-price commitments, with no re-openers for changed circumstances as NIPSCO proposed in 45195 and 45196.

Predicting the future is inherently uncertain, and the farther into the future we try to predict, the higher the margin of error becomes. Thus, we could place greater reliance on NIPSCO's projections of costs for years 1 through 5 than we could for years 25 through 30. NIPSCO's evidence did not provide us with the annual assumed cost for each portfolio, which we believe is necessary for us to make an informed decision in these cases. However, on cross-examination, ICC Exhibits CX-2-C, CX-3-C, and CX-4-C did provide us with a year by year comparison for two of the replacement portfolios, C and F.

In the Base Case, Challenged Economy, and Booming Economy scenarios, Portfolio C is materially less expensive than Portfolio F in every year through 2035. (ICC Exhibit CX-4-C) In the Aggressive Regulation scenario Portfolio C is materially less expensive in every year through 2030. For the Base Case scenario, the 20-year NPV of Portfolio C is $222,732,667 less than Portfolio F. (delta between cells C17 on ICC Exhibits CX-2-C and CX-3-C) On a 30-year NPV basis Portfolio F is only $5,973,589 less expensive than Portfolio C. (delta between cells C18 on ICC Exhibits CX-2-C and CX-3-C) In essence, by preferring Portfolio F over Portfolio C, NIPSCO is asking its customers to make a long-term bet that by losing $222,732,667 over the next twenty years, they will end up $5,973,589 better off in thirty years. The Commission doubts that is a bet most customers, if asked, would choose to make.

We understand that Portfolio's C and F are similar in that they both contain mostly renewable resources, and in both about half of the capacity is 20-year PPAs. But there are two significant differences. First, about half of Portfolio F consists of NIPSCO owned resources, like what is proposed in this case, while in Portfolio C there are no owned resources. Second, Portfolio C has significantly more short-term MISO capacity purchases. Mr. Augustine conceded that in Portfolio F the model was restrained from selecting more than 50 MW of MISO capacity purchases, and in Portfolio C the model was restrained from selecting more than 400 MW of MISO capacity purchases. (Tr. Augustine, p.158, l.8 – p.159, l.11) He conceded that had the models not been so constrained both might have selected more MISO capacity purchases as the least cost option. (*Id.*) Mr. Augustine justified so constraining the models because "least cost is not the only criteria," and "the purpose of this analysis is to evaluate and integrate a scorecard approach." (*Id.*) While we agree that least-cost is not the only criteria, it is a very important criteria, and NIPSCO's model decision making has clearly deprived both NIPSCO and the Commission of important information, namely what the least-cost portfolio would have been had the model been unconstrained, and how much less that least-cost portfolio would cost. Only with that information can reliable cost/benefit weighing of all metrics, including least-cost, be made. Without that information, NIPSCO's scorecard approach to cost/benefit weighing of multiple metrics to arrive at any preferred portfolio becomes suspect and insufficient for decision making.

Given the constraints NIPSCO imposed on its modeling there are strong reasons discussed above to prefer Portfolio C over Portfolio F. The potential benefits of Portfolio F do not appear until far in the future, and depend on assumptions made today about what technologies will exist and what they will cost in the future. As we stated earlier, "[I]n periods of seemingly quickening technological change, [we] must not ignore the risk that any such investment may become uneconomic over the long-term." *In re Vectren*, Cause No. 45052, Final Order, p.20 (April 24, 2019). However, because of the constraints NIPSCO imposed we cannot know that a portfolio of even greater MISO capacity purchases in the near-term would prove to be both less expensive and allow NIPSCO greater flexibility as the regulatory and technology horizons come into better view in the near-term.

Further, NIPSCO's failure to either use its actual replacement portfolios for its retirement analysis or design its retirement portfolios to fit into its scorecard approach prevents us from assessing whether continued operation of NIPSCO's existing coal generation beyond what NIPSCO plans might be the preferred path at this time.

Further, our decision making is inhibited by NIPSCO's decision to run its models for 20-years and but then calculate 30-year NPVs by extrapolation. Mr. Augustine conceded that the models could have been run for 30 years. (Tr. Augustine, p.170, ll.15-25) Then, he said it was unnecessary to do so because, "[T]he portfolios were designed to allow for a proper apples to apples comparison and then have an end effects analysis." (*Id.*) He further said, "So when I speak about apples to apples, there is the exact amount -- the same amount of 20-year PPAs in Portfolio C and Portfolio F that were treated identically." (Tr. Augustine, p.171, ll.10-12)

If NIPSCO believed that its analysis needed to extend 30 years or 40 years then it could have run its models for that long. However, the revelation that NIPSCO's decision to run its models for only 20 years created an external influence on its portfolio design is very concerning.

(4) Scenario and Portfolio Robustness. Commissioners in Michigan recently cautioned about IRP outcomes in which the utility's preferred outcome wins in every future scenario the utility crafted for its modeling. April 27, 2018 Order at 66, *In re DTE Elec. Co.*, Case No. in MPSC No. U-18419 (Mich. Pub. Serv. Comm'n Apr. 27, 2018), at 66 ("The Commission expects that an effective IRP should produce results, under certain scenarios, that show the preferred course of action is not actually the best option. This is how we know the IRP is testing the robustness of the preferred course of action by examining how it performs under various assumptions, even if those assumptions may seem unrealistic today.").

According to NIPSCO, its decision to acquire the wind resource proposed in this case and to enter into the PPAs involved in 45195 and 45196 is driven entirely by its IRP outcome that favors early retirement of all existing coal generation. But, ICC Exhibit CX-1 (Attachment 6-A to Mr. Augustine's Prefiled Testimony in Cause 45159) shows that NPVs for the eight Retirement Portfolios NIPSCO designed had exactly the same rank across all four of the future scenarios that NIPSCO developed (Base, Aggressive Environmental Regulation, Challenged Economy, and Booming Economy). We observe a near perfect alignment of NPVs across NIPSCO's Replacement Portfolios (*See* NIPSCO Exhibit 4, Attachment 4-A, p.165, Figure 9-21) The fact that in addition to NPV NIPSCO applied a variety of metrics to its replacement Portfolios does not prove that the portfolios and scenarios were sufficiently diverse, and as noted by the Commissioners in Michigan, the perfect alignment of NPV ranking of Retirement Portfolios across all scenarios, and the near-perfect alignment of NPV ranking of Replacement Portfolios across all scenarios, is reason for concern and perhaps investigation.

Here, whether intended or not, NIPSCO's scenario development gives the appearance of putting a thumb on the scale in favor of early retirement of its coal resources. In three of its four scenarios NIPSCO assumed near future (2026) carbon pricing. In 2008, NIPSCO cited the prospect of greenhouse gas regulation as a reason for entering into its Buffalo Ridge and Barton wind PPA. Order in 43393, p. (Jul 24, 2008) ("Another benefit of securing contractual rights to wind power today is that it will aid in compliance with future greenhouse gas ('GHG') regulation. Mr. Shambo believes utilities cannot ignore the increasing demand for GHG regulation and must develop an emission strategy that anticipates such regulation will be enacted. Moreover, investment today will more gradually reflect the additional costs resulting from GHG regulation and also avoid cost increases for renewable resources that may result after GHG regulation is passed.") It may be that carbon constraints or pricing will eventually be enacted. But given its history and current circumstances, assuming it will occur in 2026 in three out of four scenarios seems overly aggressive, and such an assumption certainly weighed against NIPSCO's existing coal generation resources as well as future portfolios with gas generation.

Then, in the only scenario in which NIPSCO did not assume carbon pricing, it introduced another assumption that disadvantaged its existing coal generation—higher coal prices coupled with low gas prices. To justify that, NIPSCO strings together a series of other assumptions. It assumes an economic downturn, which is not an unreasonable scenario to model. But it assumes because of the economic downturn no carbon pricing is enacted. Then it assumes because no carbon pricing is enacted and the weak economy, demand for natural gas falls, keeping gas prices low. Then NIPSCO makes an unprecedented leap. It assumes from all that there will be stronger coal demand causing coal prices to increase. *See* NIPSCO Exhibit 4, Attachment A-4, § 8.3.2. The problem with this string of assumptions is that NIPSCO has no historical precedent for its last leap—that coal demand and therefore coal prices would rise in a challenged economy. NIPSCO does not point to any past economic downturn when coal demand and coal prices rose. It would seem more likely that as the nation's already aged coal fleet continues to age, retirements will be forced by age alone, and demand for coal will fall whether the economy is up or down. A down economy might slow the decline, and NIPSCO's assumption of an increase in coal demand in a down economy needs more support than NIPSCO provides. Moreover, if the US economy is down, the world economy could be down also, which could depress US coal exports and put downward pressure on coal prices. We don't suggest that the last three sentences are supported by any testimony in this case. We proffer them hypothetically to emphasize that NIPSCO's rationale for assuming higher coal prices in an economic downturn is convoluted, weak, and equally unsupported by any evidence; that supports our concern that NIPSCO's development of its future scenarios was not sufficiently robust or diverse.

(5) Stochastics. We would expect NIPSCO to have performed a stochastic analysis of all the most material variables as identified by a sensitivity analysis. However, NIPSCO's IRP report indicates that a stochastics analysis was done on only a limited set of variables (commodity prices and carbon prices). (NIPSCO Exhibit 4, Attachment 4-A, §8.4).

Further, in using the outcome of its stochastic analysis, NIPSCO focused on the 75th and 95th percentiles and ignored the 25th and 5th percentiles. Apparently, NIPSCO was only concerned about high prices. But customers care about low prices too. NIPSCO's IRP analysis focuses only on the risk of high prices. But, when entering into long-term fixed-priced contracts, customers also face a risk of missing out on low future prices because they are stuck in high-priced, long-term contracts. NIPSCO's has provided no analysis of that risk that we can use to make an informed decision in these wind PPA cases.

(6) Urgency. Mr. Augustine testified on cross-examination that NIPSCO's $500 million savings claim results from comparing Replacement Portfolios F and F1 as shown in Figure 9-30 of NIPSCO's IRP. (Tr. Augustine p.150, ll.2-7). However, that is truly an apples-to-oranges comparison, because Portfolio F1 relies on new solar with storage rather than new wind resources. A proper comparison would have compared Portfolio F to a portfolio having the same amount and duration of wind generation that does not qualify for any PTC or market purchases of capacity reflecting wind's limited contribution to UCAP. NIPSCO's portfolio choices provided no such comparisons, so we have no way of knowing how much, if anything, NIPSCO customers might theoretically save or lose by NIPSCO rushing into these long-term renewable commitments in lieu of waiting a couple of years. Here again, because NIPSCO does not provide the year-by-year buildup of the costs that generate that $500 million difference, we cannot know to what extent those savings might accrue in the early years and to what extent they are predicted to accrue in later years when such predictions become more uncertain.

Finally, we express no opinion about whether or not the PTC will or will not be renewed or extended. But we note that according to the Congressional Research Bureau, the PTC has already been extended eleven times. It has been extended four times specifically for wind resources, and on six occasions it has lapsed before it was extended. (The Renewable Electricity Production Tax Credit: In Brief, November 27, 2018, table on p.4, available at https://fas.org/sgp/crs/misc/R43453.pdf (last viewed May 1, 2019)) And noted elsewhere, impending expiration of the PTC was a ground NIPSCO offered over a decade ago to support the Barton and Buffalo Ridge PPA's. In fact, the PTC did not expire then. It was extended and the rates NIPSCO customers incur under the Barton and Buffalo Ridge PPA's are significantly higher than the cost of market purchases. It is unclear why NIPSCO's assumption today is any better than the assumption made to justify those expensive contracts.

C. Load Forecast. The equation for calculating a capacity overage or shortfall is simple: capacity minus demand equals capacity overage (if positive) or capacity shortfall (if negative). Both elements of the equation—capacity and demand—must be known or estimated to do the calculation. We have already explained above that NIPSCO's evidence claims it needs the three pending wind PPAs/asset acquisitions to fill a capacity shortfall that will occur in 2023 when it retires its Schahfer coal units, but does not inform us of the magnitude or type of capacity shortfall NIPSCO expects.

What we do know, however, is that the load forecast from which NIPSCO obtained the demand element of the equation for 2023 was based on an assumption that NIPSCO's large industrial tariff structure in 2023 and beyond would be the same as it now is. What we also know is that in pending Cause No. 45159, NIPSCO seeks approval of a material change in NIPSCO's large industrial tariff structure that would allow its five largest customers to reduce their firm demand to as low as 60 MW in the aggregate,[1] "which is a potentially significant change in NIPSCO's future load profile. However, NIPSCO did not consider this proposed change, or the potential change in its load profile, in its IRP modeling." (ICC Exhibit 1, Griffey, p.5, ll.6-10)

Mr. Augustine testified that the current firm load of NIPSCO's largest industrial customers who would qualify for proposed Rate 831 is approximately 800 MW. (Tr. Augustine, p.146, ll.19-23) In Mr. Augustine's rebuttal, NIPSCO for the first time asserted the position that whatever the amount of lost industrial firm load results from Rate 831, it will be offset by about 600 MW of loss of interruptible load. (Tr. Augustine, p.182, l.23 – p. 183, l.8) That is a peak load analysis, which we acknowledge is important. However, as indicated by their relatively low UCAP values, wind resources such as proposed in this case are little relied on to satisfy peak load, because the availability of wind to power them coincident with peak is unpredictable and uncontrollable. Thus, an equally important question, especially with respect to high load factor customer like the ones who would qualify for Rate 831, is what resources does NIPSCO need most of the time to serve its load during the other 8759 hours of the year that are not the system peak? Mr. Augustine's testimony makes it appear that NIPSCO's IRP modelling may have assumed 1,200 to 1,400 MW too much load during hours other than the system peak. If the industrial load is not there, it is unlikely that take-or-pay off peak energy from wind resources will be needed to serve NIPSCO's remaining residential and commercial load that have more of a peak load shape.

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1 In a recent filing in 45159, NIPSCO and its largest industrial customers have entered into an agreement in which those customers agree to initial Tier 1 contracts under Rate 831 that in the aggregate total 177 MW. But, after the initial term of five years, nothing prevents those customers from reducing their Tier 1 contracts to 60 MW in the aggregate.

The bottom line is that NIPSCO's failure to use a long-term load forecast for its IRP modeling that is consistent with the changes in its large industrial loads that might occur were we to approve Rate 831, leaves both NIPSCO and the Commission in the dark about quantifying any capacity shortfall that might arise when NIPSCO retires any given current resource.

NIPSCO describes proposed Rate 831 as "the next step" in an evolutionary process. (Cause No. 45159, Prefiled Direct Testimony of Michael Hooper, p.13, ll.3-4) NIPSCO describes that evolutionary process as "the evolution of the market for electricity for NIPSCO as well as for its largest customers." (Cause No. 45159, Prefiled Direct Testimony of Violet Sistovaris, p.24, ll.2-3) This adds future market evolution to technological and regulatory uncertainties that presently exist. We encourage planning for the future. But, at the present time, the existence of these and other uncertainties support plans that minimize long-term contractual commitments and investments, particularly for non-peak energy, and especially those whose projected returns are negative for the initial fifteen to twenty years, and whose benefits are only projected to accrue in the far future if certain assumptions prove true.

D. Consistency with IRP. NIPSCO has claimed that the attributes of the RoseWater wind project and the wind PPAs involved in 45195 and 45196 are consistent with the assumptions it used in the IRP. However, the testimony shows (1) that NIPSCO now foresees that the UCAP for these wind projects may be materially less than what NIPSCO assumed in the IRP, (2) that expected capacity factors are all lower than NIPSCO assumed in the IRP, and (3) that the costs are higher than NIPSCO assumed in the IRP. These differences are material.

The UCAP is an indicator of contribution to satisfy NIPSCO's peak capacity obligations, both to MISO and to its customers. According to Mr. Augustine, "The preferred portfolio includes . . . approximately 1,100 MW of installed capacity ('ICAP') wind representing 157 MW of unforced capacity ('UCAP')." (Exhibit 4, p.4, ll.2-6) That is a UCAP factor of 14.27% (157 ÷ 1,100 = 0.1427). This is consistent with Mr. Griffey's testimony that in its modeling and RFP analysis NIPSCO assumed between 13.5% and 15%. (ICC Exhibit 1, p. 25, ll.8-11) Mr. Griffey also presented evidence that in Indiana (where the RoseWater project would be located) MISO assigns wind resources an average UCAP of only 7.4%. (*Id.*, p.25, l.5) This is important because had NIPSCO assumed a lower UCAP in its modeling, the model would have added another capacity resource (at some cost) to make up the difference.

The capacity factor is an indicator both of how much energy NIPSCO may expect to receive and to what extent the resource might satisfy NIPSCO's off-peak capacity obligations. If the actual capacity factor is lower than NIPSCO's modeling assumed that would lessen the value of the resource as a supplier of energy and to satisfy off-peak capacity obligations.

It goes without saying that higher actual costs than assumed costs is a negative indicator. NIPSCO did not rerun its IRP with these new costs, UCAPs, and capacity factors to determine if the RoseWater project or the PPAs in 45195 and 45196 provide net benefits to customers, nor did it demonstrate the time period over which benefits would exceed the known costs of these projects. As a result, we conclude that NIPSCO has not shown that the RoseWater project or the PPAs in 45195 and 45196 are consistent with its IRP.

E. Other Considerations. As an investor owned utility (IOU) NIPSCO is naturally inclined to prefer long-term portfolios that include owned assets on which it may earn a return. For example, ICC Exhibit CX-6-C shows, by preferring Replacement Portfolio F (which has long-term owned assets) over C (which has no owned assets), NIPSCO potentially earns hundreds of millions of dollars in additional earnings. This is not a criticism of NIPSCO or any other IOU. It is simply a fact. All other things being equal no one should object to an IOU maximizing its potential for profit. Financially healthy utilities are in the public interest. However, all other things are rarely equal. For example, NIPSCO's 30-year NPVs for Portfolios C and F make them appear relatively equal in their cost to ratepayers. But, as we have discussed above, a deeper analysis indicates that short-term Portfolio C is materially less costly and risky to ratepayers over the next fifteen to twenty years. When from a variety of potential resource portfolios, a utility seeks, as NIPSCO does, Commission authorization to implement the portfolio that potentially maximizes its profits, the utility bears a heavy burden of proof to justify that preference.

In its 2019 session the Indiana General Assembly enacted Ind. Code ch. 2-5-45 which establishes the 21st Century Energy Policy Development Task Force. That legislation directs that task force to develop recommendations for the general assembly and the governor concerning: (1) outcomes that must be achieved in order to overcome any identified challenges concerning Indiana's electric generation portfolios, along with a timeline for achieving those outcomes; (2) whether existing state policy and statutes enable state regulators to properly consider the statewide impact of changing electric generation portfolios and, if not, the best approaches to enable state regulators to consider those impacts; and (3) how to maintain reliable, resilient, and affordable electric service for all electric utility consumers, while encouraging the adoption and deployment of advanced energy technologies. A report is due no later than December 1, 2020. While nothing prohibits the Commission from approving resource retirements and acquisitions before the work of that task force is complete, the fact that such a task force will be at work in the near future and may result in changes to Indiana's regulatory regime is a factor we must consider. And, it is a factor that weighs against approving long-term contract commitments and investments before the work of that task force is complete.

In its 2019 session the Indiana General Assembly also enacted Ind. Code § 8-1-8.5-3.1 which directs the Commission to conduct a comprehensive study of the statewide impacts, both in the near term and on a long term basis, of: (1) transitions in the fuel sources and other resources used to generate electricity by electric utilities; and (2) new and emerging technologies for the generation of electricity, including the potential impact of such technologies on local grids or distribution infrastructure; on electric generation capacity, system reliability, system resilience, and the cost of electric utility service for consumers. The Commission must complete its study and issue its final report no later than July 1, 2020, so that it may be considered by the 21st Century Energy Policy Development Task Force. Again, nothing prohibits the Commission from approving resource retirements and acquisitions before that study is complete, but the fact that such a study will be performed in the near future is a factor we must consider. And, it is a factor that weighs against approving long-term contract commitments and investments before that study is complete.

F. Conclusion. We deny NIPSCO the relief it seeks because, for the reasons stated above, we conclude the evidence of record is insufficient for us to find the RoseWater project is reasonable and necessary or in the best interests of customers. In so doing, we do not intend to signal that acquisition of owned generation resources, including renewable resources, will no longer be approved. We may approve the acquisition of owned generation resources, including renewable resources, now and in the future, when the evidence is sufficient to convince us they are reasonable and necessary and in the best interests of customers. Similarly, we may approve long-term PPAs, now and in the future, when the evidence is sufficient to convince us they are reasonable and necessary and in the best interests of customers.

What we do signal by this decision is that when we are asked to approve long-lived resources with guaranteed recovery from customers over decades, we expect: (a) the evidence on need to be complete, detailed, and up to date; (b) the modeling supporting the request should reveal not just the plausible future circumstances in which the proposal is the best outcome, but the plausible future circumstances in which the proposal is not the best outcome; (c) more detail than just a single number on metrics that will accrue over long time horizons, such as cost, job gains/losses, and local economy impacts. Again, the far future is much harder to predict than the near future. Such single number metrics do not expose whether an expected overall gain is the result of relatively certain near-term losses that are offset by more speculative future gains, or vice-versa. The difference, however, might materially affect our decision making, and therefore we need sufficient evidence to know the difference.

11. Confidentiality. Joint Petitioners filed a motion for protection and nondisclosure of confidential and proprietary information on February 1, 2019. In its motion, NIPSCO states certain information redacted in the evidence is confidential, proprietary, competitively sensitive, and/or trade secrets. A Docket Entry was issued on April 25, 2019 finding such information to be preliminarily confidential and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. The confidential information was subsequently submitted under seal. The OUCC and Intervenors Indiana Coal Council, Inc. and Citizens Action Coalition of Indiana, Inc. also submitted information under seal that NIPSCO had in its February 1, 2019 motion designated as confidential, proprietary, competitively sensitive, and/or trade secrets. The Commission finds the information for which NIPSCO seeks confidential treatment is confidential trade secret information pursuant to Ind. Code§ 8-1-2-29 and Ind. Code ch. 5-14-3, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

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

1. Joint Petitioner's request for issuance to NIPSCO of a Certificate of Public Convenience and Necessity for the purchase and acquisition of a 102 MW wind farm (“the RoseWater Project”) is denied.

2. Joint Petitioners’ request for approval of the RoseWater Project as a Clean Energy Project under IC 8-1-8.8-11 is denied.

3. Joint Petitioners’ request for approval of ratemaking and accounting treatment associated with the RoseWater Project is denied.

4. Joint Petitioners' request for authority to establish amortization rates for NIPSCO's investment in the joint venture is denied.

5. Joint Petitioners' request for approval pursuant to IC 8-1-2.5-6 of an Alternative Regulatory Plan including establishment of joint venture through which the RoseWater Project will support NIPSCO's generation fleet and the reflection in NIPSCO's net original cost rate base of its investment in joint venture is denied.

6. Joint Petitioners' request for approval of purchased power agreements through which NIPSCO will receive the energy generated by the RoseWater Project, including timely cost recovery pursuant to ind. code § 8-1-8.8-11 through NIPSCO's fuel adjustment clause is denied.

7. Joint Petitioners' request for authority to defer amortization and to accrue post-in service carrying charges on NIPSCO's investment in joint venture is denied.

8. Joint Petitioners' request, to the extent generally accepted accounting principles would treat any aspect of joint venture as debt on NIPSCO's financial statements, for approval of financing is denied.

9. Joint Petitioners' request for approval an Alternative Regulatory Plan for NIPSCO in order to facilitate the implementation of the RoseWater Project is denied.

10. Joint Petitioners' request, to the extent necessary, for issuance of an order pursuant to IC 8-1-2.5-5 declining to exercise jurisdiction over joint venture as a public utility is denied.

11. The Confidential Information submitted under seal in this Cause pursuant to Joint Petitioners' request for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure under Ind. Code§§ 8-1-2-29 and 5-14-3-4.

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

FREEMAN, HUSTON, KREVDA, OBER, AND ZIEGNER CONCUR:

APPROVED:

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

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Mary M. Becerra
Secretary of the Commission