FILED
May 3, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR APPROVAL PURSUANT TO IND. CODE §§ 8-1-2-42(a), 8-1-8.8-11, AND TO THE EXTENT NECESSARY IND. CODE § 8-1-2.5-6, OF A RENEWABLE ENERGY POWER PURCHASE AGREEMENT WITH ROAMING BISON WIND, LLC, INCLUDING TIMELY COST RECOVERY.	)	**CAUSE NO. 45196**

SUBMISSION OF FORM OF PROPOSED ORDER

Northern Indiana Public Service Company LLC, on behalf of itself and Citizens Action Coalition of Indiana, Inc. and the Indiana Office of Utility Consumer Counselor, by counsel, respectfully submits the attached form of agreed proposed order. For purposes of convenience, a Word version of the proposed order will be provided to the Administrative Law Judge via email transmission.

Respectfully submitted,

Claudia J. Earls

Claudia J. Earls (No. 8468-49)
NiSource Corporate Services - Legal
150 West Market Street, Suite 600
Indianapolis, Indiana 46204
Phone: (317) 684-4923
Fax: (317) 684-4918
Email: cjearls@nisource.com

Attorney for Northern Indiana Public Service Company LLC

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by email transmission upon the following:

Jeffrey M. Reed
T. Jason Haas
Office of Utility Consumer Counselor
115 W. Washington Street,
Suite 1500 South
Indianapolis, Indiana 46204
jreed@oucc.in.gov
thaas@oucc.in.gov
infomgt@oucc.in.gov

Jennifer A. Washburn
Margo Tucker
Citizens Action Coalition of Indiana
1915 W. 18th Street, Suite C
Indianapolis, Indiana 46202
jwashburn@citact.org
mtucker@citact.org

Robert L. Hartley
Carly J. Tebelman
Frost Brown Todd LLC
201 N. Illinois Street, Suite 1900
P.O. Box 44961
Indianapolis, Indiana 46244-0961
rhartley@fbtlaw.com
ctebelman@fbtlaw.com

Todd A. Richardson
Anne E. Becker
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282
trichardson@lewis-kappes.com
abecker@lewis-kappes.com

Meghan E. Griffiths
Jennifer A. Ferri
Jackson Walker LLP
100 Congress Ave., Suite 1100
Austin, Texas 78701
mgriffiths@jw.com
jferri@jw.com

Dated this 3rd day of May, 2019.

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ORDER OF THE COMMISSION

Presiding Officers:
David L. Ober, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On February 1, 2019, Petitioner Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") in this Cause for approval and associated cost recovery of a Wind Energy Purchase Agreement between NIPSCO and Roaming Bison Wind, LLC ("Roaming Bison"), which is an affiliate of Apex Clean Energy Holding, LLC, dated January 18, 2019 ("Roaming Bison Wind Energy PPA"). On February 1, 2019, NIPSCO filed its prepared testimony and exhibits constituting its case-in-chief and a Motion for Protection and Nondisclosure of Confidential and Proprietary Information.

On February 5, 2019, Citizens Action Coalition of Indiana, Inc. ("CAC") filed its Petition to Intervene, which the Presiding Officers granted in a docket entry dated February 18, 2019. On February 28, 2019, the Indiana Coal Council ("ICC") filed its Petition to Intervene, which the Presiding Officers granted in a docket entry dated March 12, 2019. On March 11, 2019, NIPSCO Industrial Group filed its Petition to Intervene, which the Presiding Officers granted in a docket entry dated March 25, 2019.[1] On March 20, 2019, the Indiana Coalition for Affordable and Reliable Electricity filed its Petition to Intervene, which the Presiding Officers granted in a docket entry dated April 2, 2019.

In accordance with the February 8, 2019 Docket Entry setting the procedural schedule for this Cause, the Indiana Office of Utility Consumer Counselor ("OUCC") and Intervenors filed testimony and exhibits constituting their respective cases-in-chief on March 15, 2019. NIPSCO filed its rebuttal testimony on March 29, 2019. On April 23, 2019, the OUCC filed Consumer Comments.

On April 4, 2019, the parties filed a request to continue the evidentiary hearing and asked that an attorneys' conference be convened to determine a new date and time. An attorneys'

[1] The companies that comprise the NIPSCO Industrial Group are ArcelorMittal USA, Cargill, Inc., Praxair, Inc., and USG Corporation.

conference was held on April 12, 2019. At the attorneys' conference the parties agreed to an evidentiary hearing date of April 23, 2019. Subsequent to the attorneys' conference, the parties filed a request to consolidate the evidentiary hearing in this Cause with the evidentiary hearing in Cause No. 45195. By Docket Entry dated April 12, 2019, the Presiding Officers consolidated the evidentiary hearings as requested and set the hearing for April 23, 2019.

The Commission held an evidentiary hearing in this Cause on April 23, 2019 at 9:30 a.m., in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana. At such time, the direct evidence of the respective parties were admitted into the record and cross-examination was conducted of Petitioner's witnesses. The hearing was then continued to May 1, 2019 at 9:00 a.m., to allow for admission of Petitioner's late-filed notices of publication.

Having considered the evidence presented and the applicable law, the Commission finds:

1. Notice and Commission Jurisdiction. Notice of the evidentiary hearing in this Cause was given and published by the Commission as required by law. NIPSCO is a public utility within the meaning of that term as used in Ind. Code § 8-1-2-1 and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the Public Service Commission Act, as amended, and other pertinent laws of the State of Indiana. NIPSCO is also an "eligible business" as that term is defined in Ind. Code § 8-1-8.8-6. NIPSCO is also an "energy utility" within the meaning of Ind. Code § 8-1-2.5-2 and provides "retail energy service" as that term is defined by Ind. Code § 8-1-2.5-3. NIPSCO is also subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. NIPSCO's Characteristics. NIPSCO is a limited liability company organized and existing under the laws of the State of Indiana with its principal office and place of business at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO is authorized by the Commission to provide electric utility service to the public in all or part of Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren and White Counties in northern Indiana. NIPSCO owns, operates, manages and controls electric generating, transmission and distribution plant and equipment and related facilities ("Utility Property"), which are used and useful in the production, transmission, distribution and furnishing of electric energy, heat, light and power to the public. Pursuant to the Commission's Order dated September 24, 2003 in Cause No. 42349, NIPSCO has transferred functional control of its transmission facilities to the Midcontinent Independent System Operator, Inc. ("MISO"), a regional transmission organization operated under the authority of FERC, which administers the use of NIPSCO's transmission system and the economic dispatching of NIPSCO's generating units pursuant to MISO's FERC approved tariff provisions. NIPSCO also engages in power purchase transactions through MISO as necessary to meet the demands of its customers.

3. Requested Relief. In its Verified Petition, NIPSCO requested the Commission enter a Final order (1) finding that the Roaming Bison Wind Energy PPA is reasonable and necessary, (2) authorizing NIPSCO to enter into the Roaming Bison Wind Energy PPA and determining the Roaming Bison Project to be an eligible Clean Energy Project for purposes of Ind. Code § 8-1-8.8-11; (3) authorizing the full and certain recovery of the retail jurisdictional portions of the power purchase costs on an accrual basis under the Roaming Bison Wind Energy PPA from retail customers through NIPSCO's fuel adjustment clause proceedings, or successor mechanism, over the entire 20-year term of the agreement; (4) approving confidential treatment of the Roaming Bison Wind Energy PPA pricing and other negotiated commercial terms and related confidential information; and (5) granting to NIPSCO such additional and further relief as may be deemed or appropriate.

4. Statutory Framework. Ind. Code § 8-1-8.8-2 concerns the development of alternative energy sources, including renewable "energy projects." Ind. Code § 8-1-8.8-10 definition of "renewable energy resource" includes energy from wind. Pursuant to Ind. Code § 8-1-8.8-11, an energy project is eligible for timely recovery of costs. This framework provides the basis for the requested Commission assurance of purchased power cost recovery through the full terms of the Roaming Bison Wind Energy PPA. Section 42(a) also authorizes recovery of purchased electricity. Finally, Ind. Code § 8-1-2.5-6, which authorizes alternative regulatory plans, provides a further basis for the approval of the Roaming Bison Wind Energy PPA and full recovery of the costs through the full terms of the Roaming Bison Wind Energy PPA.

The Commission has previously granted relief comparable to what NIPSCO seeks in this Cause to NIPSCO, Duke Energy, Vectren South and Indiana Michigan Power Company, and in those cases we found wind power developments to be renewable resource projects. We approved the purchase agreements and timely cost recovery through a quarterly rate adjustment mechanism to be administered with the Fuel Adjustment Clause ("FAC") proceedings.

5. NIPSCO's Case-in-Chief. NIPSCO presented the testimony of three witnesses in its case-in-chief: Andrew S. Campbell, Director of Regulatory Support and Planning for NIPSCO; Patrick N. Augustine, Principal in Charles River Associates' Energy Practice; and Robert Lee, Vice President of CRA International d/b/a Charles River Associates, Inc. ("CRA").

Mr. Campbell provided testimony to support NIPSCO's request for approval of the Roaming Bison Wind Energy PPA being developed in Montgomery County, Indiana. He described the Roaming Bison Project as having an installed capacity of approximately 300 megawatts ("MW") (nameplate capacity), providing NIPSCO with 100% of the electrical output of the Roaming Bison Project, and any environmental attributes associated with the project for a term of 20 years beginning at the Commercial Operation Date. He described the process NIPSCO followed that led to the execution of the Roaming Bison Wind Energy PPA and discussed how NIPSCO will integrate the Roaming Bison Wind Energy PPA into NIPSCO's and MISO's operations. He also discussed the viability of wind energy resources generally, and the terms of the Roaming Bison Wind Energy PPA outlining NIPSCO's rights to the wind energy project's production, capacity, and environmental attributes, and the benefits associated with the environmental attributes in the form of Renewable Energy Credits ("RECs"), and NIPSCO's proposal for recovering the costs associated with the Roaming Bison Wind Energy PPA.

Mr. Campbell testified the Roaming Bison Wind Energy PPA is for products generated from a wind energy project – a clean energy resource under Ind. Code § 8-1-37-4, a renewable energy resource under Ind. Code § 8-1-8.8-10, and a clean energy project under Ind. Code § 8-1-8.8-2(2).

Mr. Campbell testified NIPSCO retained CRA in the first quarter of 2018 to assist in the design, administration and bid evaluation of an all-source request for proposal ("All-Source RFP") solicitation process. He said the All-Source RFP had a dual purpose: first to solicit binding bids to cover an anticipated capacity shortfall starting in 2023, and second to secure market-based information on the cost and performance of alternative resource options to inform and improve NIPSCO's 2018 Integrated Resource Plan ("IRP"). Mr. Campbell stated that through the process, NIPSCO received bids supported by renewable facilities, fossil resources, energy storage, and demand response options and that bids for both standalone assets and integrated facilities comprised of different resource types or supported by energy storage were submitted. He stated that bidders offered power purchase agreements ("PPAs") for the output of existing and proposed assets and assets for sale.

Mr. Campbell stated that his involvement in the All-Source RFP process was to ensure the process conformed to NIPSCO's intent to competitively bid and secure additional electric energy and capacity in the amount needed to serve NIPSCO's retail customers in the future, and to assure that CRA conducted the process in a fair and transparent manner.

Mr. Campbell testified that wind is a renewable, indigenous, and clean energy source. He stated that wind energy projects do not use fossil or nuclear fuel in operation, which means no mining or drilling for fuel, no radioactive or hazardous wastes, no use of water for steam or cooling, and no emissions of greenhouse gases or other pollutants. He said the absence of fossil or nuclear fuel also means the price of wind power is not impacted by the volatility of commodities. He stated that due to meteorological and resource diversity, the location of wind projects influences the capacity accreditation and available wind energy. Mr. Campbell stated that all three projects being proposed by NIPSCO at this time are located in Indiana, more specifically the part of Indiana with advantageous meteorological and diversity conditions. He said that for these reasons, and with advances in wind technology in areas such as wind turbine availability, capacity factor, design and size, and wind mapping,[2] wind energy has become a viable source of renewable energy resources on a per megawatt-hour ("MWh") basis.

Mr. Campbell testified that NIPSCO, in conjunction with CRA, negotiated with developers of the most viable wind energy projects. He stated that during the course of negotiations, the number of wind projects was reduced to four projects. Mr. Campbell testified that after completion of negotiations over the terms, conditions and price, NIPSCO executed three wind agreements for a total purchase of approximately 800 MW of nameplate wind power and noted that the size of each project may change slightly as engineering and technical specifications are finalized.

Mr. Campbell described Roaming Bison as a Delaware limited liability company with its principal place of business in Charlottesville, Virginia. Roaming Bison is an affiliate of Apex Clean Energy Holdings, LLC ("Apex"). Apex was founded in 2009 and builds, own and operates utility-scale wind and solar facilities with projects located throughout the county, including the PJM Interconnection LLC, Southwest Power Pool, MISO, Western Electricity Coordinating Council, Southeastern Electric Reliability Council, ISO New England, New York ISO, and Electric Reliability Council of Texas. Mr. Campbell testified that Apex provides turnkey clean energy solutions to utilities including development-transfer, build-transfer, PPAs, construction management, RFP management, asset management and construction oversight. Since its

[2] Mapping refers to the process of assessing impacts of existing wind resources, restrictions on land use, and other sensitivities that may affect wind energy.

inception, APEX has been invested in opportunities sited in places that blend the best wind resource with high potential for offtake.[3]

Mr. Campbell testified that the Roaming Bison Wind Energy PPA requires that the counterparty file for authority from the Commission to construct this project or a finding that the Commission will decline to exercise jurisdiction over the Roaming Bison Project within 45 days of signing the agreement.

Mr. Campbell testified that as part of NIPSCO's due diligence when evaluating the creditworthiness of potential counterparties, NIPSCO gathered and reviewed credit information during the pre-qualification process in the All-Source RFP. He stated counterparties that were investment grade based on their unsecured senior debt rating met the credit requirements and that if a bidder did not meet the debt rating requirement or did not have a rating, they were required to post collateral upon executing a definitive agreement. Mr. Campbell testified that Apex satisfies this collateral posting requirement and that Apex's financial ability to complete construction of the wind project, along with the ability to continue successful operation of the wind project during the term of the Roaming Bison Wind Energy PPA, is key to NIPSCO. He stated that NIPSCO has taken this into consideration by including performance security provisions in the Roaming Bison Wind Energy PPA. Mr. Campbell stated that the Roaming Bison Wind Energy PPA requires Roaming Bison to provide to NIPSCO such performance security, no later than 30 days after NIPSCO receives state regulatory approval of the Roaming Bison Wind Energy PPA, in the form of either: (1) a guaranty from a qualified guarantor; (2) a letter of credit from a qualified financial institution; or (3) cash (collectively "Security Fund"). He also noted that, in the event Roaming Bison is in default of any of its obligations under the PPA or NIPSCO is otherwise entitled to indemnification or damages under the PPA, NIPSCO has a right to access the Security Fund directly to reimburse NIPSCO for any damages or costs incurred as a result of Roaming Bison's failure to comply with its obligations under the Roaming Bison Wind Energy PPA.

Mr. Campbell testified Roaming Bison expects to construct, own, and operate a 300 MW wind energy project in Montgomery County, Indiana that will interconnect to Duke Energy Indiana's Nucor-Cayuga 345 kV transmission line via a line tap. He stated the Roaming Bison Project will be within the footprint of MISO. Mr. Campbell testified that during the Definitive Planning Phase of the MISO Generation Interconnection process, MISO performed Deliverability Analysis and Facilities Studies to determine whether transmission upgrades would be necessary and that MISO completed these analyses in 2017. In sum, Mr. Campbell said MISO determined that the energy generated by Roaming Bison would be deliverable to the point of interconnect. Mr. Campbell stated that congestion risks were assessed using MISO's future year ProMod models, which are capable of simulating hourly market operations for a given study year. He said the output was then used to determine the expected curtailments, total revenue, congestion, and loss charges for each site under consideration. Mr. Campbell stated that sites with greater congestion risk have been appropriately discounted in NIPSCO's site analysis. He stated that NIPSCO will continue to dispatch its steam and gas fleet and other available wind generation, as well as purchase power from MISO to meet customer demand and reliability needs throughout the term of the Roaming Bison Wind Energy PPA, which ensures that when the wind is not blowing customers will continue to receive reliable service every hour of every day. He stated that NIPSCO and Roaming Bison have agreed to (1) work together through an on-going operating committee

[3] www.apexcleanenergy.com/utilities/

process to establish Automatic Generation Control set points that attempt to minimize any charges related to curtailments, and (2) collaborate on any disputes prior to any formal legal process.

Mr. Campbell testified that under the Roaming Bison Wind Energy PPA, Roaming Bison commits to provide NIPSCO energy generated from approximately 300 MW of installed wind turbine capacity at a fixed price over a term of 20 years beginning at the Commercial Operation Date in 2020. He stated that the price includes the energy and all environment attributes (commonly referred to as "Renewable Energy Credits" or "RECs") associated with the energy generated by the Roaming Bison Project and metered at the point of delivery. Mr. Campbell stated that Roaming Bison will receive and retain existing and future tax credits or tax benefits as the owner and operator of the wind energy project. He testified that the Roaming Bison Wind Energy PPA provides that if cost recovery is not approved by the Commission, then either NIPSCO or Roaming Bison may terminate the Roaming Bison Wind Energy PPA.

Mr. Campbell stated that as used in the Roaming Bison Wind Energy PPA, the term "Environmental Attribute" is intended to capture any changes to governmental rules, regulations or law, or changes to registration systems put in place over the term of the Roaming Bison Wind Energy PPA.[4] He stated that NIPSCO anticipates the RECs it receives pursuant to the Roaming Bison Wind Energy PPA will be tracked through the Midwest Renewable Energy Tracking System ("M-RETS"). He explained that M-RETS is a database that tracks relevant information about renewable energy produced and delivered in the Upper Midwest, including the MISO footprint, to verify for subscribers in states with mandatory or voluntary renewable portfolio standards or for utility and other participants the RECs made available to them through REC purchases and sales. He noted that M-RETS tracks the ownership of RECs and generation attributes that result from the generation of renewable electricity.

Mr. Campbell testified NIPSCO will monitor and evaluate the marketability for the RECs and that proceeds from the sale of the RECs NIPSCO chooses to sell will be passed back to NIPSCO's customers in NIPSCO's FAC proceedings.

Mr. Campbell testified that the decision to contract for the wind was based upon NIPSCO's and CRA's analysis through the 2018 IRP that NIPSCO's customers, over the life of the projects, would save approximately $500 million due to the declining value of the Production Tax Credit ("PTC"). He stated that the Roaming Bison Wind Energy PPA plays a role in satisfying NIPSCO's electric planning goals and objectives from the 2018 IRP.

Mr. Campbell testified that federal tax incentives are currently in place for renewable and paired renewable/storage resources. He said resources are eligible for a PTC, which provides a credit of $24/MWh for all generation produced by the facility and that the tax incentive is currently in the midst of a phase-out. Mr. Campbell stated that, to qualify for the PTC, projects need to begin construction by a certain date and be put into service by a certain date. He said the start of construction deadline can be met as long as certain equipment purchases and development costs have been "safe harbored" by federal tax authorities. According to Mr. Campbell, the safe harbor

[4] Environmental Attributes acquired pursuant to the Roaming Bison Wind Energy PPA are referred to as RECs, which are tradable credits corresponding to each megawatt-hour of electricity generated by a renewable-fueled or environmentally friendly source.

for beginning of construction is investment of at least 5% of the total project cost on or before the specified date.

Mr. Campbell testified NIPSCO will take delivery of the wind energy from Roaming Bison at a specified metering point. He stated NIPSCO will be the Market Participant and will make the energy available in the MISO energy market. He testified NIPSCO will be paying Roaming Bison the contract price per MWh and counting this wind energy as used in the NIPSCO system. He stated that NIPSCO will "settle" the sale price for the wind energy sold into MISO against the price paid for the wind energy. Mr. Campbell explained that NIPSCO offers its generation and bids its load into the MISO energy and ancillary services markets daily, along with other sales and purchases, in the end "settling" the costs against revenues. He said MISO treats wind energy projects as dispatchable intermittent resources and, as such, Roaming Bison will be subject to real-time Revenue Sufficiency Guarantee and Uninstructed Deviation charges assessed under the Open Access Transmission, Energy and Operating Reserve Markets Tariff ("MISO Tariff").

Mr. Campbell testified that NIPSCO will be able to designate the Roaming Bison Wind Energy PPA as a network resource under the MISO Tariff. He stated the generator interconnection agreement that Roaming Bison will be receiving from MISO will have network resource interconnection service ("NRIS") available for its full injection once any required transmission system upgrades are complete. He noted that having NRIS will allow NIPSCO to designate this generation facility as a network resource to receive Network Integration Transmission Service without further study.

Mr. Campbell testified NIPSCO believes the Roaming Bison Wind Energy PPA will provide NIPSCO's customers with a more affordable and cleaner energy resource and that this is supported by the analysis performed in NIPSCO's 2018 IRP.

Mr. Campbell testified NIPSCO is proposing to recover the Roaming Bison Wind Energy PPA costs throughout the full 20-year term of the agreement through a rate adjustment mechanism pursuant to Ind. Code §§ 8-1-2-42(a) and 8-1-8.8.11. He stated that for administrative efficiency and simplicity, NIPSCO proposes the timely cost recovery be administered through NIPSCO's FAC proceedings (or successor mechanism). Furthermore, Mr. Campbell stated that NIPSCO is seeking approval of power purchases pursuant to the Roaming Bison Wind Energy PPA as reasonable throughout the entire term of the agreement and therefore confirmation that the costs thereof are recoverable through the FAC proceedings (or successor mechanism) without regard to the Ind. Code § 8-1-42(d)(1) test or any other FAC benchmarks.

Mr. Augustine discussed the preferred portfolio from NIPSCO's 2018 IRP and how the assumptions associated with the new wind resource options modeled in the 2018 IRP compare with the cost of the Roaming Bison Wind Energy PPA.

Mr. Augustine provided an overview of NIPSCO's preferred portfolio from the 2018 IRP and described how it was developed. He said NIPSCO's preferred portfolio retires all four coal units at the R.M. Schahfer Generating Station in 2023 and retires the Michigan City Generating Station coal plant in 2028. Mr. Augustine stated the preferred portfolio includes the following capacity replacements over time: 125 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")[5] wind representing 157 MW of unforced capacity ("UCAP")[6] 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. He noted that Section 9.3 of the 2018 IRP provides additional detail associated with the preferred replacement portfolio.

Mr. Augustine testified the plan was developed through substantial quantitative and qualitative analysis, including the use of the All-Source RFP solicitation to identify the most relevant types of resources available in the market, along with their associated costs. He stated that within the 2018 IRP, NIPSCO performed retirement and replacement assessments using robust scenario and risk-based (stochastic) analyses and scored the various portfolio alternatives against a number of cost, risk, environmental, and reliability metrics to arrive at the preferred portfolio. He stated that NIPSCO also evaluated the impact each of the retirement and replacement alternatives would have on local communities and NIPSCO's employees.

Mr. Augustine provided an overview of the 2018 IRP's Short Term Action Plan as it relates to the replacement resources in the preferred portfolio. He stated that part of the Short Term Action Plan outlined in detail in Section 9.4 of the 2018 IRP relates to selecting and acquiring replacement projects to fill the capacity gap that develops as a result of the planned retirements in 2023 in the preferred portfolio. Furthermore, he stated that in the Short Term Action Plan, NIPSCO identified a phased-in approach to selecting and acquiring these replacement resources. Mr. Augustine said the plan calls for initially prioritizing replacement resources with expiring or declining tax credits, followed by another All-Source RFP to acquire resources to fill the remainder of the 2023 supply requirement. He stated the prioritized replacement resources are wind projects looking to qualify for the PTC, which is expiring over the next few years. Mr. Augustine testified the prioritization of these resources in the Short Term Action Plan is based on the 2018 IRP's finding that procuring wind resources that qualify for the PTC saves customers nearly $500 million on a net present value basis compared to a portfolio that relies solely on solar plus storage resources to fill the 2023 capacity gap.

Mr. Augustine testified the preferred portfolio included two wind resource additions: an asset acquisition of 600 MW of ICAP (90 MW of UCAP) in 2020, and a PPA of 501 MW of ICAP (67 MW of UCAP) in 2021.

Mr. Augustine described how NIPSCO used the All-Source RFP to determine the cost and operational performance assumptions of wind resources in its IRP. He said as part of the IRP input development process, CRA organized the various bids received in the All-Source RFP into groupings or tranches according to technology, whether the bid was for a PPA or an asset acquisition, the bid's commitment duration, and the bid's costs and operational characteristics. Mr. Augustine testified that this approach allowed for the efficient development of planning-level

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5 Installed capacity or ICAP represents the nameplate capacity of a resource and the maximum amount of output that can be produced at any given time.

6 Unforced capacity or UCAP represents the expected capacity available during the system peak. For renewable resources, MISO relies on historical operational data during peak hours or generic planning numbers based on a system-wide effective load carrying capability analysis. The 2018 IRP developed UCAP numbers based on bidder responses to the All-Source RFP (where available) and generic estimates of approximately 15% of ICAP for wind resources and 50% of ICAP for solar resources.

assumptions that could be transparently shared with stakeholders and deployed in the IRP models. He stated this process resulted in the development of distinct wind sale and PPA tranches, which were eligible to be selected in the portfolio analysis in part or as a whole block of capacity.

Mr. Augustine described the specific assumptions used for the wind tranches that were selected in the preferred plan in the 2018 IRP. He said the asset acquisition of 600 MW of ICAP (90 MW of UCAP) was assumed to enter into service in the middle of 2020, with an acquisition price of $1,442/kilowatt ("kW") (in 2020 dollars) and a capacity factor of approximately 41%. Fixed operations and maintenance ("FOM") costs were assumed to be approximately $42/kW-yr (in 2017 dollars), with ongoing capital expenditures of $11/kW-yr (in 2017 dollars). Property taxes were assumed to be 2.16% of the net book value of the plant over time. He stated the PPA of 501 MW of ICAP (67 MW of UCAP) was assumed to enter into service in the middle of 2021 with a twenty-year contract duration, a fixed nominal PPA price of $25.54/MWh, and a capacity factor of approximately 42%.

Mr. Augustine testified he was able to compare the total cost of the Roaming Bison Wind Energy PPA with the total costs of these tranche-level inputs used in the 2018 IRP modeling. He stated he made such a comparison through the development of a levelized cost of electricity ("LCOE") calculation for each of the 2018 IRP resource options and the 300 MW (ICAP) Roaming Bison Wind Energy PPA. Mr. Augustine said the LCOE develops a levelized, all-in cost of a given resource option over a pre-defined analysis period on a per MWh basis and that this approach allows for a direct comparison of the costs of the different wind projects over an extended time frame by distilling all key parameters related to costs and operational performance into a single dollar per MWh number.

Mr. Augustine explained the inputs that are required to perform an LCOE calculation. He stated that for an owned resource, the following input parameters are included: the acquisition cost of the project in dollars per kW, adjusted for the contribution of a tax equity partner that can realize the benefits of federal tax incentives; NIPSCO's weighted average cost of capital and capital structure projected as of December 31, 2019; the expected FOM costs and ongoing capital expenditures over the thirty-year planning horizon; the expected property taxes over time; cash payments to the tax equity partner; and the expected generation output in MWh for the resource over time.

Mr. Augustine testified that for a PPA resource, the following input parameters are included: the PPA price in dollars per MWh over the term of the contract; the expected generation output in MWh for the resource over time; and the expected market cost to replace the generation output after the expiration of the PPA contract term if it falls within the thirty-year planning horizon. He said the expected difference between the nodal price at the project and NIPSCO's load node is an input for both owned and PPA resources in order to quantify the expected congestion risk over time.

Mr. Augustine described the LCOE values calculated for the two wind resource tranches incorporated in the 2018 IRP's preferred portfolio. He said the thirty-year LCOE of the 2020 wind acquisition was calculated to be $38.99/MWh, based on the acquisition price, capacity factor, FOM costs, ongoing capital expenditures, and property taxes summarized above and an assumed thirty-year project life. He said the thirty-year LCOE of the 2021 wind PPA was calculated to be $32.63/MWh based on the twenty-year PPA price summarized above plus an additional ten years of market-based energy costs to evaluate the total cost of energy over the full planning horizon. Mr. Augustine testified that the thirty-year LCOE of the Roaming Bison Wind Energy PPA was calculated based on a twenty-year nominal fixed PPA price plus ten years of equivalent market-based energy and UCAP capacity costs after the expiration of the contract. He illustrated how the LCOE values for the wind resource tranches incorporated in the 2018 IRP's preferred portfolio compare to the LCOE of the Roaming Bison Wind Energy PPA.

Mr. Augustine testified how the relief requested in this proceeding supports the conclusions of the 2018 IRP and its Short Term Action Plan. He testified the operational and cost characteristics of the Roaming Bison Wind Energy PPA are consistent with the assumptions for new wind resources used in the 2018 IRP, which developed a preferred portfolio with approximately 1,100 MW (ICAP) of wind additions in the 2020-2021 time period. He stated that on an LCOE basis, the cost of the Roaming Bison Wind Energy PPA is lower than the costs of the PPA and owned resource tranches evaluated in the 2018 IRP. In addition, Mr. Augustine said the generation-weighted average LCOE of the three wind projects currently being pursued by NIPSCO is lower than the generation-weighted average of the two wind tranches used in the 2018 IRP ($36.07/MWh). He stated the Short Term Action Plan called for prioritizing the acquisition of such wind projects prior to the phase-out of the PTC based on the finding that this produces substantial savings for NIPSCO's customers. Thus, Mr. Augustine testified, the addition of the Roaming Bison Wind Energy PPA to NIPSCO's portfolio in 2020 is fully supportive of and consistent with the conclusions of the 2018 IRP and the recommended Short Term Action Plan.

Mr. Lee explained the analysis NIPSCO used to evaluate its various options for wind energy and why the Roaming Bison Wind Energy PPA is an economic choice for helping meet NIPSCO's retail electric load. He described the key findings outlined in the opinion letter provided from CRA to NIPSCO following the RFP. He testified that through the Opinion Letter and its attachments, CRA recommended certain assets as potential projects to advance to a definitive agreement phase and that the assets recommended for advancement were selected based on the preferred portfolio in NIPSCO's 2018 IRP and the RFP scoring criteria developed in advance of the RFP process.

Mr. Lee sponsored Confidential Attachment 3-D providing the detailed scoring results for each project bid into the RFP. He stated that consistent with the RFP process rules, each project was evaluated based on development risk, reliability, asset-specific risk, and the estimated net present value ("NPV") of facility revenues and costs.

Mr. Lee provided an overview of NIPSCO's 2018 IRP and RFP process. He said in 2016, NIPSCO conducted an integrated resource planning process that identified a potential capacity shortfall at or around 2023 and included tentative conclusions as to future resource options. He then noted that in 2018, NIPSCO updated the 2016 IRP to ensure that resource planning reflected the most current outlook for key market drivers. Mr. Lee testified that on May 14, 2018, NIPSCO issued a news release announcing its intent to explore potential options to meet the future needs of its residential, commercial and industrial electric customers. He explained the RFP process was a component of NIPSCO's broader resource planning and analysis having a dual purpose. He said the first objective of the RFP was to solicit bids to cover NIPSCO's anticipated capacity shortfall starting in 2023 and the second objective was to secure market-based information on the cost and performance of alternative resource options to inform and improve NIPSCO's 2018 IRP.

Mr. Lee described his involvement in NIPSCO's IRP process, which began in February 2018 after the 2018 IRP process had been initiated. He explained that the All-Source RFP was intended to inform NIPSCO's resource planning and identify potential capacity assets to meet NIPSCO's needs. He stated the All-Source RFP was conducted as part of an integrated IRP and RFP process and that his role was to help design and administer the All-Source RFP process.

Mr. Lee said through the All-Source RFP, NIPSCO sought to identify the discrete capacity resources best positioned to satisfy the anticipated capacity shortfall consistent with both the 2018 IRP analysis and the RFP bid selection criteria. He said NIPSCO considered a wide range of asset types, including physical generating assets, PPAs and demand response resources. Mr. Lee stated that through the process, NIPSCO received bids supported by renewable facilities, fossil resources, energy storage, and demand response options and that bids for both standalone assets and integrated facilities comprised of different resource types or supported by energy storage were submitted. He stated that bidders offered assets under PPA arrangements and assets for sale. In addition, he said, while the 2016 IRP identified an anticipated capacity shortfall starting in 2023, NIPSCO considered bids with transfer dates or PPA start dates in advance of the identified need in 2023. Mr. Lee stated CRA served as an independent third party managing the RFP process.

Mr. Lee testified the All-Source RFP was issued on May 14, 2018 and CRA conducted a bidder conference on May 16, 2018. He said prospective bidders were required to provide a Notice of Intent, Bi-lateral Confidentiality Agreement and Pre-Qualification Application due on May 29, 2018, with final proposals ("Proposals") due on June 29, 2018.

Mr. Lee provided an overview of the All-Source RFP design and execution. He stated that prior to issuing the All-Source RFP, CRA worked with the NIPSCO team to define the process objectives and requirements. He testified that NIPSCO advised CRA that in order to ensure adequate, reliable capacity supplies to meet customer needs, it intended to acquire dispatchable, semi-dispatchable or renewable resources that, at a minimum, would meet established industry-wide reliability and performance criteria for electric generation facilities and that had physical deliverability into MISO Local Resource Zone 6 ("LRZ6"). He said CRA worked with NIPSCO to prepare the RFP documentation, ensure the product requested was clearly defined, and ensure the evaluation criteria were clearly specified in the RFP documentation.

Mr. Lee explained how CRA and NIPSCO informed interested parties about the All-Source RFP. He stated that CRA managed the outreach to potential bidders interested in the process and worked with NIPSCO to identify existing assets and projects in-development located within LRZ6 as well as potential demand response providers. He said representatives from potential bidders were contacted via electronic mail notices and phone calls, informing them of the RFP and relevant due dates and that both NIPSCO and CRA participated in public stakeholder sessions to inform interested parties about the process and the integrated IRP/RFP approach. In addition, he explained NIPSCO published a press release related to this RFP on its website on May 14, 2018 and CRA ran trade press advertising in Megawatt Daily on May 14, 2018.

Mr. Lee testified that throughout the RFP process, CRA maintained a public Information Website that warehoused all key documents related to the RFP. He explained that through that Information Website, interested parties could submit questions and comments related to the process, the documents or the RFP requirements and, when appropriate, those questions and answers were posted to the RFP Information Website to ensure all bidders had equal access to information. He said all interested parties were allowed to submit Proposals in the All-Source RFP. Mr. Lee testified that ultimately, CRA approved all pre-qualification applications submitted and notified the applicants of their pre-qualification status.

Mr. Lee testified the All-Source RFP generated substantial interest from bidders. He said NIPSCO received more bids in response to its All-Source RFP than any capacity RFP he had participated in to date. Mr. Lee noted CRA received 90 proposals supported by 59 projects across 5 states and that many of the PPA proposals included fixed or variable pricing arrangements or had options on the start date and contract term. He stated that several proposals included multiple options for facility configuration and resource sizes.

Mr. Lee testified that in total, nearly 15 gigawatts ("GW") of UCAP was offered into the RFP providing a wide range of capacity choices across technologies and deal structures.

Mr. Lee explained that CRA evaluated the economics and other scoring considerations related to each Proposal independent of NIPSCO or any NIPSCO affiliates. He said CRA reserved the right, in its sole and exclusive discretion, to reject any and all Proposals on the grounds that such Proposal did not conform to the terms and conditions of the RFP or on the grounds that the bidder did not comply with the provisions of the RFP.

Mr. Lee described how RFP bids were used to inform IRP modeling. He said he proposals received in response to the RFP were used to develop "tranches" or bundles of assets comprised of individual facilities with similar cost, performance and overall economics. He said the bid tranches were used by the NIPSCO IRP team to develop a preferred capacity plan that included a range of asset types and that the preferred plan, which set the capacity needs by asset type, was announced at a public stakeholder session conducted on October 19, 2018. He stated the RFP selected individual proposals for advancement to a potential definitive agreement phase consistent with the IRP preferred plan and based on the RFP's scoring criteria. Mr. Lee described the Proposal review and evaluation.

Mr. Lee stated that CRA reviewed all proposals that met pre-determined qualifying criteria set forth in the RFP documentation and evaluated each based on certain pre-specified evaluation criteria. He said for physical generating assets and storage assets offered under either a PPA or an asset sales structure, the evaluation considered: (1) estimated NPV of expected market revenues and costs from the present through 2043 (20 years beyond the 2023 anticipated need date), (2) asset reliability and deliverability, (3) development risk, and (4) asset-specific risk factors. He explained that Demand Response proposals were evaluated across four categories (1) cost, (2) demonstrated performance, (3) response time, and (4) proposal-specific risk factors.

Mr. Lee testified CRA evaluated the bids independent of NIPSCO. He said NIPSCO was not directly involved in the evaluation of proposals nor was NIPSCO aware of bidder identities as part of the process. He stated NIPSCO was provided general information about the level of interest in the RFP, the MW of capacity offered by asset type and deal structure. He explained that CRA also provided NIPSCO indications of the general level and range of prices received for various asset categories in order to facilitate communication with stakeholders and others interested in the NIPSCO process. He stated that during the evaluation, NIPSCO was only made generally aware of CRA's progress and was only involved with bidder-specific issues if those issues required policy or technical guidance from NIPSCO subject matter experts.

Mr. Lee discussed the IRP process conclusions and NIPSCO's preferred plan. He testified that the 2018 IRP considered a range of options around the potential retirement of existing NIPSCO fossil generation facilities and developed an optimal portfolio of assets based on detailed scenario and risk analysis and informed by comprehensive market modeling. He explained that the magnitude of the 2023 resource need was directly dependent on the conclusions derived from the 2018 IRP.

Mr. Lee stated that NIPSCO's 2018 IRP results indicate that the optimal path forward includes the medium term retirement of Schahfer Units 14, 15, 17 and 18 by 2023 and the retirement of Michigan City Unit 12 by year end 2028.

Mr. Lee testified that, given the retirement analysis conclusions included in the 2018 IRP, NIPSCO's resource requirements are greater than the ~600 MW (UCAP) initially identified in the 2016 IRP. He said that as a direct result of the expanded resource requirements, the level of capacity and the count of projects designated for advancement to the definitive agreement stage of the RFP was broader than initially anticipated.

Mr. Lee testified CRA recommended that NIPSCO advance a set of assets consistent with the IRP preferred plan to the definitive agreement phase of the process. He stated process bidders were asked to hold firm bids though December 31, 2018 and CRA's recommendations on advancement to the definitive agreement phase were subject to any potential resource constraints NIPSCO may have with respect to initiating commercial negotiations with counterparties in advance of that date. He testified the RFP was performed in a transparent, fair and nondiscriminatory manner and the process used to solicit and evaluate proposals was executed consistent with the process as defined and envisioned by NIPSCO and CRA at the outset and that no bidder was given an undue advantage or preference in the All-Source RFP.

Mr. Lee described the first step in the two-party negotiations with the developers. He explained that after identifying for NIPSCO the assets recommended for advancement to the definitive agreement phase of the process, CRA communicated with each bidder notifying them of the process status and next steps and then NIPSCO prioritized certain short-listed projects and initiated commercial negotiations with the highest priority counterparties.

Mr. Lee discussed his recommendation for NIPSCO with regard to the acquisition of wind power. He noted the IRP modeling indicated a preference for wind resources as part of the preferred portfolio. In addition, he said NIPSCO was advised that the sites amenable for wind development within Indiana may be limited, but that all project proposals supported by Indiana wind projects showed positive NPV contributions. Mr. Lee stated that, as a result, consistent with the IRP's preferred portfolio, all Indiana wind proposals submitted into the RFP process were recommended as assets to consider for advancement to the definitive agreement phase for further due diligence and analysis.

Mr. Lee testified all Indiana wind projects were not considered equal priority. He explained that part of the value offered by wind resources relates to PTC that are a function of a facility's in service date. He said wind resources that can meet a 2020 in service date qualify for the maximum tax credits and moving forward with those projects to ensure they meet the 2020 online deadline for maximum PTC qualification was considered the highest priority. Mr. Lee explained that even within the set of 2020 wind projects, certain assets were prioritized by NIPSCO due to the deal economics and capacity constraints NIPSCO faces for finalizing commercial negotiations. He stated that other projects including solar projects and wind projects targeting a 2021 online date were considered lower priority because the economics of those projects were less time sensitive.

Mr. Lee described which projects bid into the All-Source RFP had a target online date of 2020. He said there were seven (7) projects bid into the All-Source RFP with a target online date of 2020 – NextEra's Jasper Pulaski and Jordan Creek projects, EDPR's Rosewater project, APEX Roaming Bison, EON's Clinton, RES White Post and Calpine's Big Blue River project. Of these seven (7) projects, Mr. Lee explained that NIPSCO has focused to date on both NextEra projects as well as the EDPR and APEX bids.

Mr. Lee explained how NIPSCO evaluated the pricing with and without RECs and that CRA evaluated RECs qualitatively. He said certain proposals included the provision that RECs would accrue to the project developer rather than NIPSCO and that these proposals lost points in the evaluation versus projects where RECs were transferred to NIPSCO.

Mr. Lee explained why CRA valued the RECs qualitatively rather than quantitatively. He noted the value of renewable energy was incorporated into the IRP process through evaluation of portfolio costs, risks, and carbon dioxide emissions. He said given the large uncertainty associated with future regulation and the future costs of renewable resources, no explicit REC value was attributed to renewable projects in the IRP. He stated that the IRP's preferred portfolio was predominantly comprised of renewable resources even without considering the economic value RECs might provide. He said the RFP process then selected individual projects consistent with the IRP preferred portfolio. Mr. Lee testified that as a result, the RFP process evaluated wind assets versus other wind assets, solar projects versus other solar projects. He said assuming a similar facility capacity factor for like assets, assets within the same asset class would generate a similar number of RECs per MW-year and therefore similar REC values; however, in cases where RECs accrue to the developer rather than to NIPSCO, there is a different but highly uncertain value offered by one project versus another. He said that because CRA wanted that difference in value reflected in the bid evaluation, but there was not a specific REC valuation consistent with IRP modeling, projects that did not include RECs lost points through the Proposal Specific Risk scoring category; however, in all but one instance, Indiana wind projects did include RECs as part of the bid.

Mr. Lee described how NIPSCO evaluated the contract term to be included in the wind PPAs. He said that as part of the evaluation of the economics of each bid received, CRA calculated the NPV per MW-month of each bid received and that the NPV valued each facility's expected energy and capacity output versus projections of the prevailing market value for energy and capacity in Indiana derived from IRP base case modeling. Mr. Lee said for PPA bids, these value streams were offset by the bid specific PPA price offered into the RFP and for build transfer agreement ("BTA") options, the market value of the output was offset by the asset purchase price and ongoing facility expenses. He said in cases where the projected value of the facility's output exceeded the price for that output included in the PPA or the BTA costs, the proposal would yield a positive NPV. He also explained that in cases where the projected value of the facility's output was less than the price for that output included in the PPA or BTA costs, the proposal NPV would be negative. He said the sum of the discounted annual values offered by a PPA would be the total NPV for the proposal and that this total NPV was divided by the UCAP MW for the project multiplied by the number of months in the PPA term or the asset's expected life to yield a NPV per MW-month. Finally, he said the NPV per MW-month captures the total value offered across bids normalized by the bid's term length.

Mr. Lee described how NIPSCO evaluated the fixed versus escalating pricing of the wind Proposals. He said the mechanics of the NPV calculation were identical between fixed and escalating PPA proposals and that, in many cases, developers offered a single project under both fixed and escalating pricing structures at NIPSCO's option. He explained that in these cases, the NPV was calculated both under fixed and variable pricing structures and the option that yielded the highest NPV per MW-month was included in the scoring of the bid.

Mr. Lee testified each renewable facility's underlying dispatch into the MISO market was assumed to be the same under either a fixed or variable PPA structure. He said since wind, solar and other similar projects have zero or near-zero variable costs, the facilities will dispatch into the market at their maximum level regardless of the PPA pricing.

Mr. Lee described CRA's consideration of the locational marginal price-related ("LMP") impacts of the wind Proposals. He explained the prices included in the RFP NPV evaluation of bids were based on a single Indiana Hub price derived from IRP base case modeling and that, as a result, for this phase of the analysis, there was no distinction on the LMP for assets within LRZ6. He said he was aware that NIPSCO has conducted a nodal analysis of bids as part of the due diligence process during the definitive agreement phase to understand any potential congestion risk.

Mr. Lee testified the proposed Roaming Bison Wind Energy PPA is an economic option for meeting NIPSCO's retail electric load. He stated the 2018 IRP identified that based on the current market economics and outlook, wind power represents an excellent resource option for NIPSCO and its customers over the expected useful life of a new wind facility. He testified that the Roaming Bison facility represented a positive economic option based on the project's NPV score and that there were no asset specific concerns with the development project and, as a result, the facility lost no points related to asset specific risk scoring category. He stated that the Roaming Bison project received 573 total points based on the evaluation criteria used for scoring the RFP and that the project will interconnect to the Nucor-Cayuga 345 kV transmission line via a line tap.

6. **OUCC's Case-in-Chief.** The OUCC presented the testimony of Mr. Anthony A. Alvarez, Utility Analyst in the Electric Division of the OUCC; and Ms. Neha Medhekar, Utility Analyst II in the Electric Division of the OUCC.

Mr. Alvarez testified that the price for power from the project is in line with the national average. Ms. Medhekar testified that NIPSCO's proposal for cost recovery is consistent with that approved in previous IURC Orders. Mr. Alvarez indicated that the Roaming Bison filed its petition requesting that the Commission decline to exercise jurisdiction and authority over the construction and operation of the wind facility in Cause No. 45207 and that an order is expected in this Cause prior to an order in Cause No. 45207. Mr. Alvarez recommended that the approval in this proceeding should remain subject to Commission approval in Cause No. 45207. He stated that the interconnection of the Roaming Bison Wind facility required MISO upgrades and triggered network impacts in the PJM system. He indicated MISO allocated Roaming Bison $16 million and PJM allocated $9.6 million for a total of $25.6 million of network upgrade costs. He noted that NIPSCO indicated that Roaming Bison is responsible for these costs outside of the PPA contract price. Mr. Alvarez stated that Roaming Bison has not finalized the configuration and specification of the wind turbines and MISO may hold it subject to its generator modification process before it can proceed with interconnection. Mr. Alvarez notes that if MISO does not return a "non-substantive modification" determination, then MISO may not allow the interconnection to proceed. He stated that interconnection is integral to the Roaming Bison Wind Energy PPA.

Mr. Alvarez also recommended that the Commission require NIPSCO to report the following information annually for 5 years beginning with the commercial operation date: (a) the actual wind energy delivered on an hourly basis; (b) the corresponding NIPSCO Summer and Winter On-Peak and Off-Peak delivery hours identified; and (c) any and all curtailments, including specific dates, times, and reason for or cause of curtailment (the "Reporting Information").

Ms. Medhekar testified NIPSCO's proposed cost recovery treatment is consistent with prior Commission approved wind energy PPA cases, including for NIPSCO in Cause No. 43393, and for Indiana Michigan Power Company ("I&M") in Cause Nos. 44034 and 44362. She testified the Commission approved similar wind energy purchase agreements and timely cost recovery of the costs associated with such purchase agreements for I&M in Cause Nos. 43328 and 43750. She recommended the Commission authorize recovery of power purchases costs for the Roaming Bison Wind Energy PPA from retail customers through NIPSCO's FAC proceedings, or successor mechanism, over the entire 20-year term of the agreement.

7. **<u>CAC's Case-in-Chief.</u>** CAC presented the testimony of Elizabeth A. Stanton, PhD, Director and Senior Economist of the Applied Economics Clinic and a Senior Research Fellow at the Global Development and Environmental Institute at Tufts University. Dr. Stanton participated in the NIPSCO 2018 IRP stakeholder process and reviewed both NIPSCO's all-source RFP and the responses to the RFP. She evaluated NIPSCO's final 2018 IRP and co-authored comments submitted on behalf of CAC as part of that stakeholder process. *See* Attachment EAS-2. For this proceeding, Dr. Stanton confirmed that both the price to be paid under the PPA and the timing of the procurement of this wind resource were consistent with NIPSCO's 2018 IRP. Although Dr. Stanton voiced concern about some aspects of NIPSCO's IRP process, she found NIPSCO's 2018 IRP methodology and process to be a vast improvement relative to its 2016 IRP. She also commended NIPSCO for its substantial leadership demonstrated in its 2018 IRP analysis, including the utilization of an array of best practices, the ability of stakeholders to review commodity price forecasts used in the modeling, and the effort by NIPSCO to address in good faith criticisms of its 2016 IRP. Dr. Stanton recommended approval of the PPA.

8. **<u>ICC's Case-in-Chief.</u>** 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 opposed approval of the PPA due to concerns with NIPSCO's IRP. He indicated that NIPSCO's proposed service structure in its pending rate case will reduce industrial load to 50 MW, and that the issues ICC had identified with NIPSCO's IRP were borne out in these filings. Specifically, Mr. Griffey stated that: (a) congestion cost is higher than assumptions from the IRP; (b) the capacity factor of Roaming Bison is lower than the 41.8% as represented in the IRP; (c) the assumption of CO2 tax was unreasonable; (d) increased future maintenance capital for coal units were above historic levels; (e) NIPSCO ignored its proposed industrial rate structure in the IRP; (f) no curtailment costs were included in IRP (NIPSCO paid $14 million for curtailments under current wind contracts); and (g) NIPSCO calculated levelized cost of energy for 30 years but PPAs are only 20 years. Mr. Griffey contended that running Michigan City and converting Schahfer U17 and U18 to gas would produce a lower net present value rate of return than the PPAs from Jordan Creek and Roaming Bison.

Ms. Medine also alleged that the wind proceedings were premature because NIPSCO's IRP had been flawed and no director's report had been issued yet. She also contended that NIPSCO's rate case would result in a reduction in demand associated with its largest customers to just 50 MW and the early retirement of all of NIPSCO's baseload generation. ICC was critical of NIPSCO for not developing a 20 year load forecast with reduced industrial load and for only modeling a scenario for zero carbon costs with high coal prices as part of its IRP. Ms. Medine asserted that NIPSCO should have engaged an independent party to explore the same of NIPSCO's coal units rather than proposing closure, and called into question the value of long-term PPAs if the cost of wind decreases over time (effectively locking in a high price). She also noted that the cost of wind in NIPSCO's latest FAC was more than double that of its coal units and CCGTs and higher than the cost of its peaking units. Ms. Medine also opposed the PPA not being subject to NIPSCO's FAC benchmark

9. **<u>NIPSCO's Rebuttal Testimony.</u>** Messrs. Campbell and Augustine filed testimony in rebuttal to the testimony of the OUCC and Intervenors.

Mr. Campbell testified NIPSCO agrees with Mr. Alvarez's recommendation that NIPSCO's request in this proceeding should remain subject to the Commission's findings in Cause No. 45207. He stated that at the time NIPSCO entered into the Roaming Bison Wind Energy PPA, the Company was aware that the Roaming Bison Wind Farm would be required to request the Commission to decline to exercise jurisdiction and authority over the construction and operation of the wind facility. He testified this requirement was explicitly contemplated in the agreement and required that Roaming Bison file for such authority in a reasonable timeframe following execution of the PPA.

In response to Mr. Alvarez's concerns with PJM network upgrade costs, Mr. Campbell testified all network upgrade costs to the PJM system stemming from Roaming Bison Wind Farm are Roaming Bison's sole responsibility. He testified NIPSCO will pay the agreed-upon PPA price and is shielded from variable interconnection system costs, including any impact to the PJM system stemming from Roaming Bison's interconnection into MISO. He stated that when generators file for interconnection into MISO, part of their allocated costs are to "make the system whole" for any impacts to neighboring transmission systems, including PJM and that as such, PJM, as part of any MISO generator interconnection study process, will study the impact of the new, incremental generation on the PJM system and allocate costs for required network upgrades to the PJM system to each generator, as applicable. He stated the costs are dependent on which other generators are currently in-service; which new generators are expected to come online (the interconnection queue in MISO, PJM or other affected systems); the order of such interconnection requests, future planned transmission projects or upgrades; and many other factors and that as such, the allocated costs for "affected system network upgrades" can and often do vary over time. Mr. Campbell testified Roaming Bison has been allocated certain network upgrade costs due to potential impacts on the PJM system and that number has changed. He stated that based on recent discussions between Roaming Bison and PJM regarding the Roaming Bison Wind Farm, it is expected that these costs will be eliminated or significantly reduced based on the current and projected state of the system.

Mr. Campbell testified NIPSCO expects the Roaming Bison Wind Farm to go into service as expected, regardless of the costs associated with potential network upgrades. He stated that Roaming Bison bears the risk associated with possible network upgrade costs on PJM affected systems and would not have committed to the PPA with NIPSCO if the project were not viable. Furthermore, Mr. Campbell stated that through NIPSCO's due diligence, a review of the MISO interconnection and potential PJM affected systems was completed to assess the potential risks associated with the project. He testified that given the status of the general criteria outlined above, with other generators currently in-service, which new generators are expected to come online (the interconnection queue in MISO, PJM or other affected systems) and the order of such interconnection requests, as well as future planned transmission projects or upgrades, NIPSCO concluded that the risk of significant PJM network costs was reasonably low.

Mr. Campbell testified that NIPSCO agrees with Mr. Alvarez's conclusion that Roaming Bison may need to secure a "non-substantive modification" determination from MISO before it can proceed with interconnection due to changes to the deployment number, specification, and configuration of the wind turbines. He stated that Roaming Bison is aware of a potential need to secure "non-substantive modification" determination from MISO and is planning to make such request prior to commencing operation. He explained this process is typically completed within six (6) weeks of its request, including amendment of the MISO GIA. As such, the change in turbine selection at the Roaming Bison Wind Farm is not expected to delay the interconnection schedule or commercial operation of the project in any way. He said Roaming Bison will submit a generator modification request once the turbine selection and layout have been finalized. He stated that Apex has gone through this process in MISO previously, with a 100% success rate and that in each case, MISO determined that the technology change was a "non-substantive modification." Roaming Bison expects this same determination from MISO for a switch from Siemens to GE wind turbines and, if MISO requires a more extensive study process, Roaming Bison has ample time in its development and construction schedule to make this change.

Mr. Campbell testified NIPSCO agrees with Mr. Alvarez's recommendation that the Commission require NIPSCO to provide the OUCC and the Commission with an annual report ("Roaming Bison Annual Wind Production Report") for a period of five (5) years from the date of Roaming Bison's commercial operation. He stated that NIPSCO is committed to providing the data outlined by Mr. Alvarez, however, he stated that when contemplating the totality of the renewable generation included in the preferred plan outlined within NIPSCO's 2018 IRP, setting a precedent for a standalone annual report when there could be multiple projects with different commercial operation dates is burdensome and redundant. Mr. Campbell testified that the performance information that the OUCC seeks will already be embedded within NIPSCO's standard OUCC audit package in NIPSCO's quarterly FAC filings and that NIPSCO commits to provide this information for the duration of the Roaming Bison PPA, not just the first five years as requested by the OUCC.

With regard to Mr. Griffey's contention that no curtailment costs were included in NIPSCO's 2018 IRP even though NIPSCO paid $14 million for curtailments under current wind contracts, Mr. Campbell testified that NIPSCO has taken into consideration that from time to time wind resources are curtailed from operating. He stated that after the conclusion of NIPSCO's 2018 IRP, NIPSCO evaluated possible curtailments of the Roaming Bison Wind Farm and concluded that they are expected to be de minimus.

Mr. Campbell disagreed with Ms. Medine that it is premature for NIPSCO to enter into and be granted recovery of the costs associated with the Roaming Bison Wind Energy PPA. He said that, as he explained in his direct testimony, and as NIPSCO detailed in its 2018 IRP, wind projects that qualified for the higher levels of the PTC offered a significant value for customers. He explained that aligning the on-boarding of new resources with the retirement of existing resources is not always possible and the phase out of the PTC represents an economic incentive to acquire qualifying projects while they are still viable. He stated that this also allows NIPSCO to obtain new elements of its future portfolio at a more sustainable pace and that, once the PTC phase out occurs, there is no guarantee that wind will become less expensive. He explained that, in fact, as evidenced by the responses in NIPSCO's All-Source RFP, generally, wind that is projected to go into service earlier is more economic than wind going into service later. Furthermore, he testified that NIPSCO currently has a need for capacity since retiring the Bailly Generating Station and, as such, there is currently enough room to acquire the early wind detailed in the IRP preferred plan.

Mr. Campbell testified that while the $/MWh figures from NIPSCO's most recent FAC filing (Cause No. 38706-FAC-122) quoted by Ms. Medine are accurate, he did not agree with the context in which they were utilized by Ms. Medine. He explained that NIPSCO's FAC filings only include a portion of the costs associated with the operation of NIPSCO's coal and natural gas assets and that there are additional fixed and variable costs associated with the on-going operation of those assets not captured in the FAC because they are embedded in base rates. He stated that while the incremental wind cost is higher in the FAC, it represents the total cost associated with the generation and is more economic for customers when considering the total cost of production, which is supported by the retirement analysis within NIPSCO's 2018 IRP.

Mr. Campbell testified the PPA costs should be excluded from NIPSCO's Purchase Power Benchmark. He stated this treatment is consistent with the ratemaking treatment granted for NIPSCO's existing wind agreements (approved in Cause No. 43393) and other renewable energy NIPSCO purchases pursuant to its Renewable Energy Feed-In Tariff (Rate 765) (approved in Cause Nos. 43922 and 44393). He testified it is also consistent with the treatment approved for numerous other PPAs granted by the Commission for other utilities.[7] Mr. Campbell testified NIPSCO views purchases made pursuant to PPAs as an alternative to other types of generation that NIPSCO would otherwise own, regardless of the technology, and much of the cost of those assets are recovered through base rates rather than the fully loaded costs being used to develop the Purchase Power Benchmark. Furthermore, he said the Purchase Power Benchmark is constructed in a manner in which it is meant to provide an incentive to a utility's generation portfolio (owned and contracted resources via PPAs) to be available at times of high hourly market prices to act as a physical hedge. He testified subjecting a long term PPA that locks in a fully costed resource is neither consistent with past precedent nor consistent with the treatment of Company-owned resources.

In response to Ms. Medine's concern for the value of long-term PPAs if the cost of wind decreases over time, effectively locking in a high price, Mr. Campbell testified that NIPSCO believes it is prudent to lock-in the PPA with the Roaming Bison Wind Farm for a 20-year term. He explained that, in general, new projects require a long term commitment to attract the financing required to build the project and that these durations tend to be between 15 to 20 years. He stated

[7] *See*, for example, Duke Energy Indiana, Inc. in Cause No. 43097, Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. in Cause No. 43259, and Indiana Michigan Power Company in Cause No. 43328.

this is supported by the bids received by NIPSCO in its All-Source RFP where there were, generally, very few short term options available. He testified that through the IRP and the subsequent due diligence analysis, the expected LCOE associated with the Roaming Bison PPA represents a significant savings relative to NIPSCO's existing generation at a term that fits within the confines of the planning horizon.

Mr. Augustine responded to Mr. Griffey's broad concerns that NIPSCO's 2018 IRP contains flaws and does not demonstrate that early retirement of the coal fleet and replacement with renewables is prudent or economical for ratepayers, that the cost and operational expectations for the Roaming Bison project are not consistent with the assumptions used in NIPSCO's 2018 IRP, and that NIPSCO's LCOE analysis, which was used to compare Roaming Bison with the 2018 IRP assumptions, is unreasonable. With regard to the general concerns with the 2018 IRP, Mr. Augustine testified that he responded to each of those concerns in his rebuttal testimony in NIPSCO's currently pending rate case (Cause No. 45159) and incorporated that testimony as Confidential Attachment 2-R-A.

Mr. Augustine testified that overall, Mr. Griffey did not provide any evidence that would dispute the findings from NIPSCO's 2018 IRP, nor NIPSCO's assertion that the Roaming Bison PPA is fully consistent with those findings. He said Mr. Griffey lacked a basic understanding of the MISO market as well as a basic understanding of the LCOE analysis NIPSCO performed to support its request, resulting in a series of unfounded claims regarding the Roaming Bison Project's cost-effectiveness. Mr. Augustine said Mr. Griffey had not presented any actual market analysis of his own to contradict the clear findings from NIPSCO's 2018 IRP, which demonstrates that new wind resources are lower cost than existing coal plants, and that Mr. Griffey's efforts to adjust NIPSCO's LCOE analysis were all based on false premises.

Mr. Augustine testified that Mr. Griffey's assertion that using a 20-year NPV instead of a 30-year NPV might have resulted in a different outcome is completely without merit. He said that Mr. Griffey asserts that adjustments in the portfolios that replace coal with renewables are needed, while ignoring the adjustments that would be needed in portfolios that retain coal longer. Mr. Augustine added that Mr. Griffey failed to acknowledge that the 20-year NPVs that NIPSCO calculated and produced in its 2018 IRP all showed significant savings associated with coal plant retirements.

Mr. Augustine explained NIPSCO performed a detailed, fundamentals-based dispatch and portfolio cost accounting analysis over a 20-year time period using the Aurora model. He said to arrive at a 30-year NPV calculation, variable portfolio costs from the Aurora simulations were then extrapolated beyond the fundamental time period, while the full revenue requirement calculations associated with capital investments during the 20-year modeling period, including depreciation and return analysis, were continued. He added that, as is standard practice in utility resource planning, "end-effects" extrapolations like this are often performed to extend the analysis time period in order to account for the value of long-lived assets and the relative difference in portfolio costs that have developed after 20 years of fundamental modeling.

Mr. Augustine explained that Mr. Griffey's claims that the PPAs in NIPSCO's renewable portfolio would have expired by 2038 is false. Mr. Augustine said that the PPAs all extended into the 2040s, with start dates ranging from 2021 to 2023 with 20-year terms.

Mr. Augustine also noted that when Mr. Griffey asserted that NIPSCO needs to raise renewable costs significantly after 2038, he contradicts a claim made by ICC Witness Medine that wind costs will fall sufficiently in the future, such that they become lower than current costs, inclusive of tax credits. While Mr. Augustine also took issue with Ms. Medine's claim, he further explained that it is contradictory that the ICC can take both sides of an argument in the same proceeding depending on which assumption helps their case at any given point in time.

Mr. Augustine also testified that although NIPSCO's end-effects calculation has implications for *all* elements of portfolio costs beyond 2038 and through 2047, Mr. Griffey claims only that renewable costs need to be adjusted upwards to reflect the fact that they will be higher cost than the PPA prices NIPSCO received in the All-Source RFP conducted as part of the 2018 IRP. Mr. Augustine testified that Mr. Griffey ignores the adjustments that would need to be made in portfolios that retain coal through the 2038 fundamental modeling period. Mr. Augustine cited Retirement Portfolio 1 as an example, which retains Schahfer Units 17/18 through end-of-life, which would be around 2038. Mr. Augustine explained NIPSCO's end-effects approach currently does not include any new maintenance capital or replacement resources beyond 2038. Therefore, he said, if one were to attempt to adjust the end effects calculation to reflect a more fundamental long-term view, extra costs would need to be considered for this portfolio in addition to the other one Mr. Griffey targets.

Mr. Augustine also concluded that the 20-year NPV savings associated with NIPSCO's preferred retirement portfolio versus the portfolio that retained all coal was still above $3 billion. He explained that Mr. Griffey's implication that the final ten years of the NPV calculation would change any of NIPSCO's conclusion is inaccurate and that Mr. Griffey selectively adjusts certain numbers in isolation, often without cause, which is no substitute for the comprehensive portfolio and revenue requirement analysis NIPSCO has performed leading to its conclusions in the 2018 IRP.

Mr. Augustine testified that Mr. Griffey's statement that "assigned UCAP for wind varies across the zones in the MISO system based on how likely the wind resource is to operate during MISO's peak demand hours" is not a fair representation of MISO's process and shows that Mr. Griffey misunderstands MISO rules in multiple ways. First, MISO does not assign wind resources capacity credit by zone rather, new wind resources get credit at the system-wide level. Second, the process is not based on "how likely" the wind resource is to operate, but uses actual metered data for operational wind farms, citing to MISO Business Practices Manual No. 011, which states: "A wind farm with no commercial operation history during the Summer will receive a wind capacity credit equivalent to the MISO system wide wind capacity credit from the ELCC study for their initial Planning Year, and thereafter metered data will be used in order to calculate its future wind farm specific wind capacity credit."[8]

Mr. Augustine testified that Mr. Griffey's cite to a Planning Year 2018/19 MISO wind report to support his claim that UCAP for wind resources will be lower in Indiana and that capacity credit is likely to decline over time presents an historical view of realized wind capacity credit by zone, whereas the Business Practices Manual presents the actual process for calculating such credit, which will be based on the actual performance of a new project. Mr. Augustine explained

[8] ELCC refers to effective load carrying capability. See page 34 of 192 of the public version of MISO Business Practices Manual No. 11 for Resource Adequacy, effective February 20, 2019. The Manual is available at: https://www.misoenergy.org/legal/business-practice-manuals/

that the historical capacity credit for wind resources within Zone 6 has varied by year as a result of market and wind conditions and the fact that there are less than 300 MW of wind registered in Zone 6, a small sample size of data points to rely upon. Mr. Augustine testified that in the report for Planning Year 2019/20, capacity credit values for Zone 6 wind resources have increased to 7.8%, with the system-wide capacity credit up to 15.7% and that Zone 6 resources have also historically realized capacity credits as high as 9.3%[9] in recent years. Mr. Augustine provided information regarding the 2013 and Planning Year 2019/20 reports, noting a nearly 30% increase in the expected capacity credit with 30 GW of wind penetration due to increased geographic diversity and better technological performance for wind plants. Mr. Augustine went on to explain it is possible for the wind capacity credit to increase over time if the penetration of solar resources shifts the effective peak hour of the day and hence the effective load carrying capability value of wind resources that perform better later in the evening.

Mr. Augustine testified he is not implying that there is no risk that the wind projects will realize capacity credits below the 15% and 13.5% assumptions used in the 2018 IRP but merely trying to present a more balanced view of the current state of the market than Mr. Griffey does with his claim that 7.4% is the only reasonable planning assumption that NIPSCO should use. Mr. Augustine testified NIPSCO has been transparent about capacity credit risk throughout the production of its 2018 IRP and stated explicitly in the 2018 IRP that it expects that "both wind and solar renewable capacity credit will change over time with increased renewable penetration levels"[10] and that, "if capacity credit rules or methodologies change, NIPSCO's 2018 IRP path can be cost-effectively scaled to adjust."[11] He said NIPSCO plans to pursue a geographically diverse set of different renewable resource types in a staged fashion to address this risk. He noted NIPSCO concluded in the 2018 IRP "[b]y not committing to any single, large asset for the majority of UCAP needs, NIPSCO can flexibly adapt as rules and technologies change."[12]

In response to Mr. Griffey's claims that other resources would have been chosen in NIPSCO's 2018 IRP analysis if wind resources were given a lower UCAP value, and that it is "quite possible that Aurora could have selected a new CCGT or the coal-to-gas conversion of Schahfer 17/18, Mr. Augustine testified that , as demonstrated in NIPSCO's 2018 IRP, sufficient low cost renewable capacity and energy was available from the RFP to retire all of NIPSCO's coal capacity by 2023 and generate significant savings for customers.

Regarding Mr. Griffey's concerns that NIPSCO should have performed nodal pricing analysis to incorporate congestion costs for wind in its 2018 IRP and not just for this proceeding, Mr. Augustine testified that the IRP is a long-term planning exercise intended to develop directional resource guidance using a range of long-term assumptions for a large set of inputs, including market power prices. Mr. Augustine testified NIPSCO acknowledged the existence of congestion and nodal price risk for new resources in its 2018 IRP[13] and has now done significant due diligence around congestion risk in its selection of the preferred wind projects to carry out its short-term action plan from the 2018 IRP. Mr. Augustine testified NIPSCO performed a nodal price forecast analysis using its PROMOD model and transmission topology data available from

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9 See MISO Planning Year 2015/16 Wind Capacity Credit Report: https://cdn.misoenergy.org/2015%20Wind%20Capacity%20Report124859.pdf

10 See 2018 IRP, p. 177.

11 Ibid

12 Ibid

13 See page 177 of the 2018 IRP.

MISO's Transmission Expansion Plan ("MTEP") process and that NIPSCO used MTEP's Accelerated Fleet Change scenario, along with assumptions for NIPSCO fleet retirements and commodity prices that were consistent with those used in NIPSCO's 2018 IRP. He explained that, as demonstrated by NIPSCO's LCOE analysis, after including expected future congestion for the wind projects, the weighted average LCOE of the wind resources currently under consideration is *lower* than the weighted-average LCOE of the wind resources assumed in the 2018 IRP without congestion costs.

Mr. Augustine testified Mr. Griffey did not perform any alternative nodal pricing analysis and that his claims that NIPSCO's fundamental congestion pricing analysis is not valid because NIPSCO's cost analysis did not incorporate the cost of new transmission is not a fair criticism. Mr. Augustine explained that NIPSCO is part of MISO, the Regional Transmission Organization that coordinates system planning and shares costs across load serving entities in the region. Mr. Augustine stated that costs associated with upgrades necessary to facilitate the Schahfer retirement have been included in the analysis and that other regional costs are less dependent on specific NIPSCO action since they are in other service territories or allocated more broadly across the system. Mr. Augustine noted that if NIPSCO customers are unable to realize the benefits of low-cost renewables, such as the wind project in this proceeding, it does not mean that the utility's customers would be absolved from paying for broader system upgrades associated with MISO's fleet evolution. Furthermore, Mr. Augustine explained, in the case of Roaming Bison, project-level interconnection costs are being absorbed by the project developer, meaning that NIPSCO is already paying for these costs in the PPA price that has been offered. He stated that Mr. Griffey did not produce any analysis that would estimate the expected transmission costs that he claims are missing and he has not raised any questions regarding the well-vetted transmission assumptions that MISO itself develops for the nodal pricing congestion analysis NIPSCO performed.

In response to Mr. Griffey's suggestions that curtailment costs could be significant for the project, Mr. Augustine stated that NIPSCO also evaluated curtailment for Roaming Bison, and NIPSCO's analysis found no curtailment in 2022 and projected approximately 0.2% of the project's expected generation to be curtailed in 2027 and 2032. He noted that Mr. Griffey did not perform any analysis that would demonstrate a larger risk of curtailment.

Mr. Augustine concluded that NIPSCO's approach with regard to congestion risk in the 2018 IRP and in this proceeding is very reasonable and appropriate. He stated that, as is standard practice in the industry, NIPSCO evaluated resource options on a zonal level in its 2018 IRP, and the historical data regarding the relative pricing history of the existing coal fleet and the new candidate wind options supports that approach. Furthermore, he stated that, as part of its resource selection process, NIPSCO performed detailed congestion analysis to ensure that new projects would not introduce any cost risk beyond what was assumed in the 2018 IRP.

In response to Mr. Griffey's belief that NIPSCO's LCOE analysis is not useful on a stand-alone basis and that the calculations contain unreasonable comparisons, Mr. Augustine summarized how NIPSCO performed its LCOE analysis and how it was related to the 2018 IRP. He testified that NIPSCO relied on its 2018 IRP to conclude that new wind additions would provide substantial savings to NIPSCO's customers. He said such savings were demonstrated against portfolios that preserved coal capacity and against a portfolio that retired coal plants, but replaced the capacity with non-wind renewable resources. He explained the 2018 IRP analysis performed extensive dispatch analysis and detailed revenue requirement calculations and provided clear evidence that wind resources acquired in the 2020-2021 time period are far less costly than maintaining NIPSCO's current coal fleet. Mr. Augustine testified that the LCOE analysis performed by NIPSCO in this proceeding was then conducted to ensure that the cost profile of the selected wind resource, in this case Roaming Bison, was similar to the assumptions used in the 2018 IRP, which were based on a combination of bids from NIPSCO's RFP.

In response to Mr. Griffey's belief that this analysis is not valid because an LCOE calculation can only be used to compare resources that are likely to operate at the exact same times, Mr. Augustine testified the LCOE analysis is a standard tool used in the industry to compare the relative costs of different resource options on a per MWh basis.

Mr. Augustine testified Mr. Griffey's claims that NIPSCO should have used a lower UCAP for Roaming Bison in the LCOE analysis, and his adjustment of the LCOE upward to add replacement capacity costs is unreasonable. He noted that after asserting that LCOE calculations are only valid for like resources, Mr. Griffey proceeds to accept the IRP's assumptions for capacity credit, while discounting the UCAP value of Roaming Bison, establishing a dissimilar comparison. Mr. Augustine said this analysis burdens Roaming Bison with extra capacity costs, while accepting the 2018 IRP assumption that wind resources would receive a higher capacity credit. He testified Mr. Griffey assumes that replacement capacity would have to be procured at a price of $84/kW-yr. based on an unsubstantiated assertion that, "because the amount of capacity is greater than 50 MW, it would be more appropriate to use the cost of new entry as a replacement cost"[14] instead of the forecast of capacity prices NIPSCO used in its 2018 IRP. Mr. Augustine explained MISO's cost of new entry ("CONE") price has never been reached in the market, and prices at this level are highly unlikely to be sustained for a long time period in a market dominated by vertically integrated utilities subject to state-level regulation, as reflected in CRA's fundamental projection of future capacity prices. For comparison, Mr. Augustine noted Mr. Griffey uses a cost assumption of $84/kW-yr. for capacity in his calculation, while the last four MISO capacity auctions for Zone 6 have cleared at $3.65/kW-yr., $0.55/kW-yr., $26.28/kW-yr., and $1.27/kW-yr. Furthermore, Mr. Augustine said NIPSCO's RFP concluded that many other resource alternatives in the market are lower cost than MISO's CONE estimate.

In response to Mr. Griffey's adjustment of the LCOE calculation based on his claim that there is no reasonable basis to assume that congestion costs will change without transmission investment, Mr. Augustine testified this is just an arbitrary adjustment, based on Mr. Griffey's lack of understanding of the MISO market, and is completely without merit

With regard to the LCOE Mr. Griffey claims is more appropriate for Roaming Bison after his adjustments, Mr. Augustine testified NIPSCO found that the LCOE of continuing to operate its five coal units ranged between approximately $57/MWh and $82/MWh, and Mr. Griffey's own assumptions would conclude that wind resources provide substantial savings versus holding the current coal fleet.

In response to Ms. Medine's concerns about the 2018 IRP process and assumptions, Mr. Augustine testified the IRP is a planning document and is not subject to a ruling or formal approval by the Commission and, in fact, by rule, the IRP Director's Report produced by the Commission "shall not comment on the desirability of the utility's preferred resource portfolio or a proposed

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14 Griffey testimony, p. 26, lines 8-9.

resource action in the IRP."[15] Therefore, he testified that NIPSCO is not obligated to wait for any action from the Commission regarding its IRP submission before using its conclusions to support any resource decisions. He went on to explain that NIPSCO conducted a transparent IRP process, conducting six public advisory meetings over the course of 2018, along with many individual meetings with stakeholders to provide information and receive feedback on the methodologies and assumptions used in the 2018 IRP. He testified that as part of this process, NIPSCO performed several stakeholder-requested analyses prior to the submission of the 2018 IRP, including some requested by Ms. Medine and the ICC. Mr. Augustine testified NIPSCO consistently found that its preferred portfolio would provide significant savings, even in the scenarios developed by Ms. Medine.

Mr. Augustine testified that he responded to each of Ms. Medine's claims regarding the 2018 IRP in his rebuttal testimony in NIPSCO's currently pending rate case (Cause No. 45159) and incorporated that testimony as Confidential Attachment 2-R-A. He testified that as shown in this attachment, Ms. Medine's claims are all without merit and fail in any way to contradict NIPSCO's finding that new renewable additions are lower cost for customers than maintaining the current coal fleet. In response to Ms. Medine's suggestions that NIPSCO's 2018 IRP may have come to a different conclusion if it had more fully evaluated industrial load loss, Mr. Augustine testified NIPSCO did evaluate a low load scenario in the 2018 IRP, which was based on substantial industrial load leaving the system, and it found that retiring coal units provided savings to customers in this scenario.

Mr. Augustine stated that Ms. Medine's claims that this scenario biased the "outcome in favor of early retirement of existing coal resources by assuming both high coal prices and carbon taxes," is a false statement and a complete misrepresentation of the scenario. He stated that NIPSCO's 2018 IRP scenario with low load included *no* carbon taxes and actually advantaged the coal plants versus the Base Case as a result, and even with no carbon price and low load, it still found that retiring coal early and replacing it with renewable resources provided significant cost savings to customers.

In response to Ms. Medine's suggestion that NIPSCO should not be locking into long-term commitments, including the PPA with Roaming Bison, without evaluating industrial load loss risk in more detail, Mr. Augustine stated that it is important to note that since NIPSCO is part of the MISO market, the competitiveness of the existing coal fleet versus the alternative renewable resources in the preferred portfolio is not predominantly driven by NIPSCO's internal load obligations, but by the cost structure of the different resources and their position in the market. Furthermore, he explained that any future loss of firm load can be managed through NIPSCO's procurement of replacement resources, a strategy that is less risky than the one Ms. Medine advocates. He testified that investing in and maintaining the high-cost coal units, on the other hand, could result in NIPSCO having more high-cost capacity than it needs if load obligations were to fall significantly.

Mr. Augustine disagreed with Ms. Medine's claims that "[l]ocking into a 20-year wind contract exposes NIPSCO customers to potentially higher costs if the cost of wind generation declines." He testified NIPSCO's request includes a wind project that takes full advantage of the PTC, which will ramp down to zero over time after 2020. He testified that NIPSCO has found that

[15] See 170 IAC 4-7-2.2

the value of the PTC is greater than potential future cost declines in underlying wind technology, and Ms. Medine has provided no evidence to the contrary.

Mr. Augustine explained that Ms. Medine primarily references the fact that wind costs have declined since 2010 as per the International Renewable Energy Agency ("IRENA") and the National Renewable Energy Laboratory ("NREL"), cites one footnote in an NREL report indicating that the weighted average cost of capital ("WACC") for wind projects is likely to decline over time as the production tax credit ramps down, and one footnote about future WACC for wind projects to assert that "NREL is not overly concerned about continued wind investment without the PTC."[16] He stated that in discovery, Ms. Medine also indicated that, "the fact that pricing under NIPSCO's two existing wind PPAs is considerably higher than what is proposed in the proposed PPA" is supportive of her claim. Mr. Augustine testified that, while the historical cost declines she references are true, Ms. Medine's assertion that NREL is not "overly concerned" about continued wind investment is not based in any fact, nor does this statement actually say anything about the relative costs to NIPSCO's customers of wind entering into service in 2020 versus wind entering into service in the future.

Mr. Augustine testified that NREL produces an Annual Technology Baseline ("ATB") assessment of future technology costs, including for wind technology and that this is the primary source used by NIPSCO to project future cost declines for wind resources over time beyond the period of time that relied on the RFP bids. Mr. Augustine stated that Ms. Medine's use of NREL's ATB projections of future wind costs don't support her claim and that NREL's base case projections show annual declines of less than one percent in real dollars over time, which are offset by expected inflation growth, which is consistent with the long-term projections used in NIPSCO's 2018 IRP. Mr. Augustine noted that NREL also produces a low case with more aggressive cost declines, amounting to an approximate 32% reduction in nominal wind costs for projects coming online in 2031 (the lowest cost year in NREL's projections) relative to 2020. Mr. Augustine testified that this 32% cost decline for new wind in the NREL low case would not be sufficient to offset the loss of the PTC. He stated that NIPSCO's analysis has shown that the PTC is worth approximately 55% of the total installed costs of a project coming online in 2020 with a capacity factor in the range of the projects currently being pursued by NIPSCO. Mr. Augustine testified that even in NREL's low case, acquiring wind now would be the preferred, low-cost strategy versus waiting and confirmed this was the finding in NIPSCO's 2018 IRP and is the primary reason why no additional wind resources beyond PTC-eligible RFP options were selected in the preferred portfolio.

Mr. Augustine concluded that Ms. Medine's claim that waiting for wind costs to decline could prevent NIPSCO from locking into higher cost wind is completely without merit. He testified that NIPSCO has found that replacing coal with renewable resources actually reduces risks substantially for customers. Mr. Augustine testified that NIPSCO's 2018 IRP analysis concluded that renewable additions, including wind, were far less risky than holding coal, since portfolios that retired coal early and replaced capacity with renewable resources were lower cost across all scenarios and performed best on all risk metrics from NIPSCO's stochastic analysis.

Mr. Augustine disagreed with Ms. Medine's assertion that, "the situation most analogous [to NIPSCO's] is the recent failed attempt by Southwestern Electric Power Company

[16] Medine testimony, p. 12, lines 13-14.

("SWPECO") [sic] to obtain a CPCN for its ownership share (70 percent) of the 2000 MW Wind Catcher Project in Oklahoma." He presented multiple differences between that situation and NIPSCO's. He also provided numerous recent examples of utilities that are in situations far more relevant to NIPSCO's and that received approvals to add wind to their portfolios, demonstrating that state commissions have found cause to approve wind applications in cases similar to NIPSCO's. He stated that even more important than these anecdotes, however, is the fact that NIPSCO has proven through extensive analysis that the Roaming Bison wind addition is cost-effective for its customers.

10. <u>Commission Discussion and Findings.</u> Indiana Code § 8-1-8.8-11 provides that "[a]n eligible business must file an application to the commission for approval of a clean energy project" and that "[t]he commission shall encourage clean energy projects by creating [certain] financial incentives for clean energy projects, if the projects are found to be reasonable and necessary." In addition, "energy from wind" is specifically listed as one of the clean energy resources in Ind. Code § 8-l-37-4(a)(l) through Ind. Code § 8-l-37-4(a)(l6), thus making it a "renewable energy resource" under Ind. Code § 8-1-8.8-10. We find the Wind Project meets the definition of a "clean energy project" and is eligible for financial incentives.

According to Ind. Code § 8-1-8.8-11, the Commission shall encourage clean energy projects by creating financial incentives for such projects, if found to be reasonable and necessary. NIPSCO's proposed ratemaking terms with respect to the Wind Project are consistent with Ind. Code § 8-1-8.8-11 and also deliver benefits to customers.

The evidence in this Cause supports a finding that the energy to be obtained from the Roaming Bison Wind Energy PPA is needed by NIPSCO, is reasonably priced compared to other alternatives, and provides other material benefits. Notwithstanding the objections raised by the other parties, we find the terms of the Roaming Bison Wind Energy PPA to be reasonable and necessary, and we approve the Roaming Bison Wind Energy PPA and authorize NIPSCO to recover the full Wind PPA costs from retail customers. The Commission's specific findings are as follows:

A. <u>Need for the Wind PPA.</u> NIPSCO Witness Campbell testified that regardless of the proposed retirement of the Schahfer Generating Units in 2023, NIPSCO currently finds itself capacity short. The assumed capacity available from this Wind PPA would fill only a portion of the shortfall. Witness Augustine, in rebuttal, also noted that despite the criticisms of NIPSCO's IRP, NIPSCO modeled every scenario requested by the stakeholders, and in each instance, the Wind resources were more economic than other resources. The record reflects that within its IRP process, NIPSCO considered 90 proposals supported by 59 projects across 5 states with different generation resources for modeling, including natural gas, coal, wind, solar, battery storage, and demand response. The record reflects that NIPSCO also engaged and considered stakeholder input throughout the process. While the Director's Report has not yet been issued regarding NIPSCO's IRP, the Commission would note that 170 IAC 4-7-2.2 specifically provides that the Director's Report neither approves nor disapproves an IRP. And, in this case, there is strong evidence in the record that NIPSCO utilized an array of best practices, including conducting an all source RFP to inform model inputs which gave NIPSCO an unusual level of credibility from which to forecast the cost of utility scale, supply-side generators; transparent inclusion of input forecasts, outputs, and assumptions; a thorough description of most aspects of screening and portfolio selection; and fair consideration of a wide range of supply-side alternatives without arbitrary limitations on the amount of those resources that can be selected or unsupported cost additions. In addition, as stated recently in Cause No. 45052, "the Commission retains authority to review a project at any time." *Petition of Vectren South*, Cause No, 45052 (Apr. 24, 2019) at 19. The evidence is uncontradicted that NIPSCO has a need for capacity at this point in time. Based upon the evidence presented, the Commission finds that NIPSCO has shown a need for the requested Wind PPA.

B. Reasonableness of the Terms of the Roaming Bison Wind Energy PPA. The record establishes that the Roaming Bison Wind Energy PPA is the result of a thorough RFP process and a quantitative and qualitative evaluation of the RFP responses. The record further demonstrates that the terms of the Wind PPA were reached after arms-length negotiations. NIPSCO will only pay for the energy it receives at a set price established by the Roaming Bison Wind Energy PPA. Roaming Bison retains the responsibility for the construction, ownership, operation and maintenance of the facilities.

As we stated in Cause No. 45052, "[O]utcomes 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.* at 20. We find that the energy provided through the Roaming Bison Wind Energy PPA is a reasonable and necessary addition to NIPSCO's portfolio of generating resources necessary to meet the need for electricity within NIPSCO's service area, while also mitigating the risk through the diversification and use of an economic mix of capacity resources that provides flexibility. The record shows that the addition of the Roaming Bison Wind Energy PPA to the resource mix will provide needed energy and capacity. NIPSCO's evidence established that it reasonably modeled the Roaming Bison Wind Energy PPA in its 2018 IRP. Mr. Lee also demonstrated that the Net Present Value Utility Costs analysis showed that acquiring the wind energy from Roaming Bison was superior to other options available to NIPSCO, including not acquiring wind.

C. Cost Recovery. NIPSCO proposes the timely cost recovery be administered through NIPSCO's FAC proceedings (or successor mechanism). A review of Ind. Code § 8-1-8.8-1 *et seq.* demonstrates, and we find, that the Roaming Bison Project satisfies the statutory definition of an "energy project" defined in Ind. Code § 8-1-8.8-2 in that the project will develop alternative energy sources, including renewable energy. We further find that the project also qualifies as "renewable energy resources" as defined by Ind. Code § 8-1-8.8-10. Ind. Code § 8-1-8.8-11 provides that renewable energy projects, such as the Roaming Bison Wind Energy PPA, are eligible for incentives, including timely recovery of costs. We further find that the costs to be incurred pursuant to the Roaming Bison Wind Energy PPA are reasonable throughout the term of the Roaming Bison Wind Energy PPA. Based on the record evidence, the Commission finds that the recovery of all of the purchased power costs related to the purchase over the full term of the Roaming Bison Wind Energy PPA should be approved. We further find that NIPSCO should recover the Roaming Bison Wind Energy PPA costs through its FAC proceeding (or successor mechanism). As Mr. Campbell explained in rebuttal, the cost included in the PPA includes all costs of the resource, not just the energy component. Based upon the evidence presented and prior Commission precedent in other wind PPA proceedings, we find that NIPSCO's recovery of its Roaming Bison Wind Energy PPA costs should not be subject to the Section 42(d)(1) test or any other FAC benchmarks.

D. Reporting Requirements. The OUCC recommends the Commission require

NIPSCO to report the following information annually for 5 years beginning with the commercial operation date: (a) the actual wind energy delivered on an hourly basis; (b) the corresponding NIPSCO Summer and Winter On-Peak and Off-Peak delivery hours identified; and (c) any and all curtailments, including specific dates, times, and reason for or cause of curtailment (the "Reporting Information"). In rebuttal, NIPSCO agreed to provide the Reporting Information as part of its FAC filings for the duration of the Roaming Bison PPA. We find that NIPSCO shall include the Reporting Information in its FAC filings in Cause No. 38706-FAC-XX, commencing at the commercial operation date of the wind farm for the duration of the Roaming Bison PPA.

E. Conclusion. We find the evidence of record in this proceeding supports approval of the Roaming Bison Wind Energy PPA and the proposed method of cost recovery. The Roaming Bison Wind Energy PPA terms and costs are reasonable, it provides needed energy, diversifies NIPSCO's supply portfolio, provides environmental benefits, and defends against fuel cost volatility. These attributes provide direct benefits to all stakeholders. We find the Roaming Bison Wind Energy PPA costs should be recovered through a Section 42(a) tracking mechanism to be administered through NIPSCO's quarterly FACs.

11. Confidential Information. On February 1, 2019, NIPSCO filed a motion for protective order, which was supported by affidavit showing documents to be submitted to the Commission were trade secret information within the scope of Indiana Code §§ 5-14-3-4(a)(4) and (9) and Indiana Code § 24-2-3-2. On February 19, 2019, the Presiding Officers issued a Docket Entry finding the information described in the request for confidentiality to be confidential on a preliminary basis. After reviewing the designated confidential information, we find all such information qualifies as confidential trade secret information pursuant to Indiana Code § 5-14-3-4 and Indiana Code § 24-2-3-2. This information has independent economic value from not being generally known or readily ascertainable by proper means. NIPSCO takes reasonable steps to maintain the secrecy of the information and disclosure of such information would cause harm to NIPSCO. Therefore, we affirm the preliminary ruling and find this information should be exempted from the public access requirements contained in Indiana Code Ch. 5-14-3 and Indiana Code § 8-1-2-29, and held confidential and protected from public disclosure by this Commission.

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

1. NIPSCO is hereby authorized to engage in the Wind Energy Purchase Agreement with Roaming Bison or its assigns and successors.

2. NIPSCO's Wind Energy Purchase Agreement with Roaming Bison or its assigns or successors, shall be and is hereby approved and authorized as Renewable Energy Projects.

3. NIPSCO is hereby authorized to recover the Roaming Bison Wind Energy PPA Costs over their full term pursuant to Ind. Code §§ 8-1-2-42(a) and 8-1-8.8-11, to be administered within NIPSCO's fuel adjustment charge ("FAC") proceedings (or successor mechanism). This recovery shall not be subject to any tests or FAC benchmarks.

4. NIPSCO shall including the Reporting Information in its FAC proceedings, as set out in Paragraph 10(D) above.

5. NIPSCO's request for confidential trade secret treatment is hereby granted, and such Confidential Information shall be excepted from public disclosure.

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

<u>HUSTON, FREEMAN, KREVDA, OBER, AND ZIEGNER CONCUR:</u>
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