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**CLEAN GRID ALLIANCE'S COMMENTS REGARDING
DUKE ENERGY INDIANA'S 2018 INTEGRATED RESOURCE PLAN**

Dear Ms. Karn and Mr. Borum:

Enclosed are Clean Grid Alliance's ("CGA") comments regarding Duke Energy Indiana's ("Duke") 2018 integrated resource plan filed on July 1, 2019 ("Plan"). CGA's comments address the following eight points: [1] Duke's Plan is overly conservative on renewable development and does not account for growing customer demand for renewable generation; [2] Duke's modeling should be modified to reflect more reasonable assumptions on renewable generation, evaluate system needs on an hourly or sub-hourly basis, and should procure a balanced mix of renewable resources and not continued reliance on natural gas resources; [3] Duke should use verified third-party data sources for cost and performance assumptions; [4] delaying wind additions until 2024 misses an opportunity to benefit from the production tax credit; [5] Duke should use an all-source RFP on an annual basis; [6] Duke should offer a well-designed green tariff program; and [7] Duke should plan transmission expansion to deliver electricity from its forecasted generation to its customers at the lowest overall production cost of electricity.

Respectfully submitted,

/s/

Brian Rybarik
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Clean Grid Alliance

COMMENTS

CGA is concerned that Duke's Plan presents a missed opportunity to truly update the utility's resource mix for the future. Duke reports that currently "over 90% of Duke Energy Indiana's total energy is currently generated by burning or gasifying coal."¹ While the Plan eventually moves Duke to a cleaner future, it does so in overly conservative increments and with a focus on adding gas generation to replace coal rather than renewable generation. While CGA appreciates that Duke is adding storage and renewable generation (which reduces its carbon emissions and intensity), Duke is not nearly aggressive enough with its plans for renewable generation. Duke can and should do more.

Customer demand for renewables is a significant driver for utilities across the country to move to renewable generation. Sustainability minded customers will locate elsewhere if renewable generation is not a significant and growing part of the resource mix. As is further identified below, renewables make sense from a cost perspective as well.

CGA submits the following comments and recommendations for the Commission's and Duke's consideration.

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¹ Plan at 23.

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1. DUKE’S PLAN NEEDS TO ACCOUNT FOR CUSTOMER DEMAND AND ADD RENEWABLES MORE AGGRESSIVELY

Duke identifies a goal of this Plan is to minimize “environmental impact, including carbon emissions.”² When the starting point is having 90% over your energy from coal generation,³ a reduction in carbon emissions and carbon intensity is not a surprise. Indeed, it should be an expectation. While replacing coal generation with gas generation (the preferred plan adds 1,240 megawatts (“MW”) of gas generation in 2028 and 2034, coinciding with planned retirement of large plants in those years) will reduce carbon emissions and carbon intensity, Duke has the opportunity to achieve even greater reductions in CO₂ emissions by moving more quickly to cost-

² *Id.* at 56.

³ *Id.* at 23.

effective, no emission and no fuel-cost renewable generation.

Duke prefers a “Moderate Transition” portfolio because, among other things, “environmental regulation surrounding carbon emissions are uncertain.”⁴ While it is certainly true that there is some policy uncertainty, focusing so myopically on environmental regulatory uncertainty fails to account for the full story, and leads to a plan that is unnecessarily conservative with respect to the adoption of renewable generation. Duke is missing opportunities to increase the diversity of its generation fleet, minimize fuel cost uncertainty, meet growing customer demand for renewable energy, and enhance economic development opportunities for Duke and the state of Indiana.

Utilities across the country are seeing the need to proactively (and in many cases aggressively) pursue renewable development to meet customer demand. For example, Xcel Energy (a multi-state electric and natural gas utility operating in eight states) released a plan to reduce its CO₂ emissions 80% below 2005 levels by 2030, and to serve all customers with 100% carbon-free electricity by 2050.⁵ Similarly, Consumers Energy in Michigan is pursuing a plan that by 2040 will eliminate coal generation, reduce carbon emissions by 90% from 2005 levels and serve customers with 90% clean energy resources.⁶ The driver for these plans is not environmental regulations, but by stakeholder expectations.⁷

Customer demand for renewables is clear in Indiana and across the country. Companies have made their commitment to purchase renewable energy very clear, with a growing number of

⁴ *Id.* at 19.

⁵ Xcel Energy, “Building A Carbon-Free Future, Carbon Report 2019,” at 4, available at: <https://www.xcelenergy.com/staticfiles/xe/PDF/Xcel%20Energy%20Carbon%20Report%20-%20Mar%202019.pdf> (“Xcel Carbon Report”).

⁶ Consumers Energy, “2019 Clean Energy Plan,” at p. 2 (2019), available at: <https://www.consumersenergy.com/-/media/CE/Documents/sustainability/integrated-resource-plan-summary.ashx?la=en&hash=9F602E19FE385367FA25C66B6779532142CBD374> (“Consumers Clean Energy Plan”).

⁷ Xcel Carbon Report at 4; Consumers Clean Energy Plan at 3.

companies setting renewable energy and energy-related sustainability targets. 63% of the Fortune 100 companies have set one or more renewable energy targets, with 48% of the Fortune 500 making similar commitments.⁸ Additionally, 162 companies have signed the RE100 commitment to procure 100% renewable electricity to power their operations, including tech companies like Apple, Facebook, Google and Microsoft as well as current Indiana employers General Motors, Nestlé, Walmart, Iron Mountain, Johnson & Johnson, Target, Walmart and others.⁹ Duke's Plan does not address this significant customer demand for renewable energy and misses an opportunity.

Customer demand makes renewable energy an economic development issue for Duke and the state of Indiana. When utilities show leadership and advance renewable energy, they are able to attract and retain employers and businesses (like the RE100 members) that want more renewable energy. Duke needs to signal a greater commitment to renewable energy to capture this economic development opportunity. This signal is particularly important right now in Indiana where the Indiana Legislature passed and Governor Holcomb signed into law House Bill 1405 providing tax incentives for the establishment of data centers in Indiana.¹⁰ The law provides exemptions from the state sales tax for items such as electricity, equipment and construction costs for up to 50 years, depending on the size of the investment.¹¹

Data centers that can claim this exemption are going to be large since the investment requires is significant.¹² Large data center entities like Amazon, Microsoft and Facebook all have

⁸ Ceres, "REPORT: Fortune 500 Companies Accelerating Renewable Energy, Energy Efficiency Efforts." (April 2017), available at: <https://www.ceres.org/news-center/press-releases/report-fortune-500-companies-accelerating-renewable-energy-energy>.

⁹ RE100, "Companies" (2019), available at: <http://there100.org/companies>.

¹⁰ See, IC 6-2.5-15, Gross Retail and Use Tax Exemption for Data Center Equipment

¹¹ IC 6-2.5-15-14.

¹² See *id.* (indicating that the investment required is \$750 million).

public commitments to powering its operations with renewable energy.¹³ As a specific example, in announcing plans to build a 400,000 square foot, \$1.3 billion data center in Iowa, Apple CEO Tim Cook said Iowa's renewable energy resource was "paramount for us" and "if we couldn't [procure renewables], we would not be here." The Apple data center will be located in the service territory of MidAmerican Energy Company, which is nearly complete with its plan to serve customers with 100% renewable target by 2021¹⁴ – two years before Duke will add any significant additional renewable generation under this Plan.

Duke and the Commission should observe that other Indiana utilities are taking a proactive approach to customer demand for renewables. In its recent Integrated Resource Plan, Northern Indiana Public Service Company, LLC (“NIPSCO”) identified a preference to retire coal generation and develop significant amounts of wind and solar generation.¹⁵ NIPSCO is seeking to add an additional 1,049 MW of wind generation by 2021. Their plan also considers adding solar, with a total of over 3,000 MW of solar generation expected by 2038.¹⁶ To the contrary, Duke’s plan would add just over 1,600 MW of solar generation and 600 MW of wind starting in 2023, despite the fact that Duke has nearly two times the customers that NIPSCO does. If Duke does not adjust to a more proactive approach to renewables, they will be at a significant competitive disadvantage.

CGA recognizes that there is some risk with a ‘if you build it, they will come’ approach. However, this concern is mitigated by the fact that the trends are clear: renewable generation is

¹³ Brad Smith of Microsoft, “We’re Increasing Our Carbon Fees As We Double Down On Sustainability,” (April 15, 2019) available at: <https://blogs.microsoft.com/on-the-issues/2019/04/15/were-increasing-our-carbon-fee-as-we-double-down-on-sustainability/>; Amazon, “The Climate Pledge” (September 19, 2019), available at: <https://blog.aboutamazon.com/sustainability/the-climate-pledge>.

¹⁴ MidAmerican Energy Company, “MidAmerican 100% Renewable Vision,” available at <https://www.midamericanenergy.com/100-percent-vision>.

¹⁵ NIPSCO, “2018 Integrated Resource Plan” (October 31, 2018).

¹⁶ *Id.*

cost-competitive with other resources (see Section 2, below), Indiana policy is encouraging forward-looking companies like data centers to locate in Indiana, and customer demand for renewables is driving the marketplace. There is much greater peril in the fact that if you do not build renewable generation, companies with sustainability goals will not come and Indiana will miss economic development opportunities. While this concern can be mitigated by the development of a Green Tariff program (see Section 7, below), utilities across the country are taking a much more proactive approach and companies can (and are) locating in places where renewable generation is available. Duke should increase its commitment to renewable generation both by increasing the total amount and by accelerating the integration prior to 2023.

2. DUKE’S MODELING SHOULD REFLECT MORE REASONABLE COST ASSUMPTIONS FOR RENEWABLE RESOURCES

Duke identifies that “forecasting the cost of renewable energy technologies over the IRP planning period is difficult at best.”¹⁷ Duke developed its technology costs with support from a third-party, which appears to be the Energy Information Administration’s (“EIA”) Annual Energy Outlook (“AEO”) for 2017.¹⁸ In the EIA’s 2017 report, the total levelized cost of energy (“LCOE”) for onshore wind is identified as \$44.3/megawatt hour (“MWh”) and solar PV is \$58.1/MWh.¹⁹ Given the modest amount of renewable energy proposed in the Plan, Duke’s costs figures for renewable energy appears to be out of touch with other, more reliable publicly available third-party data.

In fact, the EIA recently updated the data set used by Duke. The most recent AEO for 2019

¹⁷ Plan at 75.

¹⁸ Plan at 131.

¹⁹ Energy Information Administration, “Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017,” p. 7 Table 1a (April 2017), available at: http://www.dnrec.delaware.gov/energy/Documents/Offshore%20Wind%20Working%20Group/Briefing%20Materials/2017_EIA_Levelized%20Cost%20and%20Levelized%20Avoided%20Cost%20of%20New%20Generation%20Resources_Annual%20Energy%20Outlook%202017.pdf.

updated the price for wind generation, with a significant reduction to \$36.6/MWh and solar PV reduced to \$37.6/MWh.²⁰ This data was available in February 2019. While CGA does not believe that the EIA AEO data represents reasonable cost estimates, Duke should have reassessed its Plan to account for the reduced costs for renewables identified by the EIA during its requested 8 month filing extension.

As addressed in further detail in Section 3, Duke should use a broader view to verify its cost assumptions. NIPSCO was able to establish some level of certainty on pricing by reviewing and incorporating a broad range of publicly available cost data in combination with an All Source request for proposals (“RFP”). Using this process, NIPSCO identified that the levelized cost for standalone wind power purchase agreements (“PPAs”) at \$25.54/MWh and \$38.11/MWh, with \$28.68/MWh, assuming the availability to serve customers by 2023 and account for use of the federal Production Tax Credit (“PTC”).²¹ These figures show significantly lower costs than the EIA data Duke relied on.

Duke relies on cost assumptions that appear to be high, and not based on the experience in the region with respect to the LCOE of renewable generation. Duke should incorporate lower values in their modeling, which would likely alter the resources selected; resulting in more renewable generation resources being found as the most cost-effective.

Duke notes that the “Moderate Transition portfolio also has the flexibility to adjust for different forms of carbon regulation (including no regulation) as well as changing economics of renewables.”²² Duke already needs to adjust its Plan to be consistent with the changing economics

²⁰ Energy Information Administration, “Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019,” p. 7 Table 1a (February 2019), available at: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

²¹ *Id.* at 3.

²² Plan at 19.

of renewables.

3. DUKE SHOULD USE VERIFIED THIRD-PARTY DATA SOURCES TO INFORM COST AND PERFORMANCE ASSUMPTIONS

Duke should use verified third-party data sources to inform its future cost and performance assumptions for potential resource additions. This is a significantly better starting point for cost estimates than Duke's use of the EIA AEO.

In fact, CGA does not believe that the EIA AEO data reflects a reasonable data source. The custom learning rates that EIA applies to generation technologies in order to calculate future cost and performance assumptions have historically proven inaccurate for renewable energy. Specifically, the EIA has repeatedly underestimated future deployments across the country.²³

Looking to the future, Duke should adjust its data sources. The NREL-ATB estimates that capital costs for onshore wind projects in wind regimes similar to MISO Local Resource Zone 6 will fall from approximately \$1,579/kW to \$1,316/kW by 2023, eventually falling to \$834/kW by 2030.²⁴ This data is consistent with the MISO process, which incorporates ATB data into its planning processes. Importantly, the MISO data confirmed in its Transmission Expansion Plan process, shows that the cost curve for wind will continue a significant downward trend over the next decade.²⁵

A similar outcome for solar generation is expected with anticipated advancements in PV technology. The NREL-ATB low estimates for utility-scale solar PV capital costs near Chicago should be used for the early analyses prior to collecting RFPs. For a Low Cost analysis, Duke uses

²³ EIA, "Electricity Market Module." February 2019, available at: <https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf>.

²⁴ National Renewable Energy Laboratory, "NREL Annual Technology Baseline," Onshore Wind tab. (2018), available at: <https://atb.nrel.gov/>.

²⁵ MISO, "MTEP19 Futures Development," (February 14, 2018), available at: <https://cdn.misoenergy.org/20180214%20PAC%20Item%2003a%20MTEP19%20Futures%20Development125886.pdf>.

an all-in cost for solar of \$1,250/kW for ten years of the analysis. The NREL-ATB projects installed capital costs of solar near Chicago to be approximately \$1,105/kW in 2018, decreasing to \$925/kW by 2023, and falling to approximately \$851/kW by 2030.²⁶ Continued cost reductions combined with capacity factor improvements will apply downward pressure on wind's and utility-scale solar's LCOE as federal tax credits phase out. However, the point is clear: *wind and solar energy are already cost-competitive without the federal tax credits in many geographic and technological scenarios.*

Onshore Wind

Other data sets are reflecting the declining costs of renewable generation. While this data set was released after the submission of the Plan, the recently released Lazard Associates' LCOE Analysis Version 13.0 reports a \$28-54/MWh LCOE without subsidies or incentives for U.S. onshore wind projects, making it the lowest cost source of new generation compared to all other resources. Natural gas combined cycle costs are identified as \$44-\$68/MWh.²⁷ For the Technology Resource groups most likely to be used for onshore wind development in Indiana (TRG5 and TRG6²⁸), NREL-ATB reports a \$42-\$50.43/MWh LCOE without incentives for 2018 (in \$2018).²⁹ Looking ahead, the NREL ATB projects that LCOE without incentives for U.S. onshore wind projects will fall to \$32.601-\$46.23/MWh (in \$2018) by 2023. NREL-ATB's data for 2019 forecasts an even lower price for onshore wind in 2023, with prices in TRG 5 and 6 ranging from \$26.70 to \$42.00/MWh in \$2019. Renewable suppliers agree prices will continue to decline.

²⁶ National Renewable Energy Laboratory, "NREL Annual Technology Baseline," Solar – Utility PV tab. 2018, using an annual inflation rate of 2.5%. Available at: <https://atb.nrel.gov/>.

²⁷ Lazard, "Lazard's Levelized Cost of Energy Analysis – Version 13.0," at 2 (November 2019), available at: <https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf>.

²⁸ Wesley Cole et al., National Renewable Energy Lab, "Regional Energy Deployment System (ReEDS) Model Documentation: Version 2016" at 10 (November 2016); available at: <https://www.nrel.gov/docs/fy17osti/67067.pdf>.

²⁹ National Renewable Energy Laboratory, "NREL Annual Technology Baseline." (2018), available at: <https://atb.nrel.gov/>.

NextEra Energy Resources Chief Executive Officer Jim Robo recently said that, due to continued turbine price reductions, “without incentives, early in the next decade wind is going to be a [\$20-\$25 per MWh] product.”³⁰

Solar

For utility-scale solar resources, Lazard reports a \$32-\$44/MWh LCOE without subsidies or incentives.³¹ The NREL ATB low forecast reports a slightly higher LCOE than Lazard without incentives for the Chicago area in 2018, at approximately \$37.80/MWh in \$2018.³² Looking ahead, however, the NREL ATB low data projects that the LCOE without incentives for utility-scale solar projects near Chicago will fall from that \$37.80/MWh in 2018 to approximately \$22.10/MWh by 2030 (in \$2018).³³

Continued Performance Improvements In Wind And Solar

Technological advances will continue to drive cost reductions and performance improvements for wind and solar projects. The use of taller turbine towers and longer turbine blades significantly increases the energy capture, improving project performance and reducing final costs. The LBNL Annual Wind Technologies Market Report documents how the average onshore wind turbine rotor diameter has increased from approximately 80 meters in 2008 to 113 meters today.³⁴ Since the area swept by the turbine blades, and therefore the energy captured, is

³⁰ Recharge News, “NextEra expects US tax overhaul to translate into cheaper turbines,” (January 29, 2018), available at: <https://www.rechargenews.com/wind/1422041/nextera-expects-us-tax-overhaul-to-translate-into-cheaper-turbines>.

³¹ Lazard, “Lazard’s Levelized Cost of Energy Analysis – Version 13.0,” at 2 (November 2019), available at: <https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf>.

³² National Renewable Energy Laboratory, “NREL Annual Technology Baseline.” 2018, after adjusting for inflation using an annual inflation rate of 2.5%. Available at: <https://atb.nrel.gov/>.

³³ *Id.*

³⁴ Lawrence Berkeley National Laboratory, “2018 Wind Technologies Market Report,” at 24-26 (Aug. 2019), available at: <https://www.energy.gov/sites/prod/files/2019/08/f65/2018%20Wind%20Technologies%20Market%20Report%20FINAL.pdf>.

proportional to $\pi*r^2$, this corresponds to a nearly 100% increase in swept area and energy capture.

The wind industry has also transitioned towards taller towers. Approximately 37% of all wind turbines installed in 2017 had hub heights of at least 90 meters, a significant shift away from the 80-meter hub height used in recent years.³⁵ These technologies allow turbines to access higher, steadier wind speeds, unlocking a greater range of viable wind project sites. Indiana has seen this technological change where the Meadow Lake VI wind project, brought online at the end of 2018 in White County, Indiana, is utilizing 136-meter rotor diameters and 105-meter hub heights.³⁶

4. DELAYING WIND ADDITIONS TO 2024 MISSES THE OPPORTUNITY TO TAKE ADVANTAGE OF THE PTC.

The Plan indicates that under the Moderate Transition approach, Duke will not add any wind generation until 2024.³⁷ Delaying additions until 2024 misses the opportunity to take advantage of the PTC, which is set to expire at the end of 2020. This is a significant missed opportunity since the 100% PTC value reduces the LCOE for onshore wind by approximately \$15-\$19/MWh.³⁸ This cost reduction is reflected in the LBNL Annual Wind Technologies Market Report, which shows the national average price for wind PPAs signed in 2017 and 2018 to be less than \$17/MWh.³⁹

NIPSCO clearly recognized the value of acting quickly to benefit from the federal PTC. Its

³⁵ Lawrence Berkeley National Laboratory, “2018 Wind Technologies Market Report” at 33-34 (Aug. 2019), available at: <https://www.energy.gov/sites/prod/files/2019/08/f65/2018%20Wind%20Technologies%20Market%20Report%20FINAL.pdf>.

³⁶ EDP Renewables North America, “Meadow Lake Wind Farm,” Webpage; see Vestas V136 3.6MW turbines, available at: <http://meadowlakewindfarm.com/>.

³⁷ Plan at 80.

³⁸ Lawrence Berkeley National Laboratory, “An Analysis of the Costs, Benefits, and Implications of Different Approaches to Capturing the Value of Renewable Energy Tax Incentives,” (May 2014), available at: <https://emp.lbl.gov/sites/all/files/lbnl-6610e-ppt.pdf>.

³⁹ Lawrence Berkeley National Laboratory, “2018 Wind Technologies Market Report”, at 59, see also Fig. 58 at 65 (Aug. 2019.), available at: <https://www.energy.gov/sites/prod/files/2019/08/f65/2018%20Wind%20Technologies%20Market%20Report%20FINAL.pdf>.

IRP confirms that procuring wind resources by 2020, in order to secure the 100% PTC, will be “important to achieve the lowest portfolio costs for customers,” and it has taken steps to procure said resources, announcing plans this year to procure 800 megawatts (“MW”) of wind capacity from three separate wind projects in Indiana.⁴⁰

While it may be too late for Duke to take advantage of the PTC, there are 20,450 MW of utility-scale renewable, hybrid (generation + storage) and battery storage resources in the PJM and MISO queues looking to develop in Indiana.⁴¹ Duke should issue an RFP immediately to determine what opportunities remain in the market.

5. DUKE SHOULD ISSUE AN ALL-SOURCE RFP ON AT LEAST AN ANNUAL BASIS

Unlike NIPSCO, Duke did not perform an All-Source RFP solicitation as part of its IRP process. NIPSCO’s RFP was designed to minimize future cost trend uncertainty and to identify transactable projects to serve near-term capacity needs.⁴² In response to the RFP, project developers submitted bids for 59 individual projects spread across 5 states representing over 13 GW of installed capacity, with multiple bids including variations on pricing structure and term length. NIPSCO found the RFP results were “relatively consistent with the third-party data review, but renewable offers were at the low end of the estimates observed in the public literature,” indicating that “technology change and developer activity in a competitive process are dynamic forces that influence the costs of resource options for NIPSCO in the future.”⁴³ Given how informative this process was for NIPSCO, CGA recommends that Duke perform a similar All Source RFP on an annual basis.

⁴⁰ NIPSCO, “2018 Integrated Resource Plan,” at 173 (October 31, 2018).

⁴¹ PJM and MISO queue information were reviewed on December 2, 2019.

⁴² NIPSCO, “2018 Integrated Resource Plan,” at 54 (October 31, 2018).

⁴³ *Id.* at 56.

Duke needs to perform an All Source RFP to ensure, for itself and its customers that, it is making cost-effective decisions. The RFP results would provide up-to-date information on the cost and performance characteristics of renewable energy available in the market. The results would also allow Duke to evaluate multiple configurations for renewable resources with different performance levels and pricing assumptions. Wind, solar, and storage costs are falling rapidly. Wind's costs have fallen by 69% since 2009 alone and technology advancements are opening up new viable project sites every day.⁴⁴

An annual RFP would provide Duke with project-specific pricing and performance characteristics, supplementing other information sources that Duke should use like the NREL ATB. It would be most informative to issue an annual RFP for resources not just located in Indiana, but to all resources with deliverability to MISO Local Resource Zone 6. Duke should seek information on both asset purchases and PPAs. If the RFP responses indicate that renewable resources are uneconomic, then Duke should not procure those resources, and there is no harm to ratepayers. However, if the results reveal economic resources, pursuing those options will provide net benefits to ratepayers. An RFP ensures fair and low rates for customers by putting all resources, both utility-owned and third-party, on the same competitive playing field.

6. DUKE SHOULD PROCURE A BALANCED MIX OF RENEWABLE RESOURCES

Duke's preferred plan includes 600 MW of incremental wind capacity additions by 2037, and a total of 1,637 MW of solar in the same timeframe.⁴⁵ As noted above, this is a very conservative plan and Duke should act more quickly and more aggressively on integrating

⁴⁴ Lazard, "Lazard's Levelized Cost of Energy Analysis – Version 12.0." (November 2018), available at: <https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf>, 8.

⁴⁵ Plan at 80. CGA notes that the generation portfolio in Table I.1 on page 20 misstates the Moderate Transition portfolio expansion that is described on page 80.

renewables into its resource mix.

That stated, CGA also encourages Duke to be vigilant in procuring a balanced mix of renewable resources over its long-term planning horizon. The preferred plan is nearly a 3:1 ratio of solar to wind generation. While the appropriate renewable energy mix is not based on installed capacity alone since dynamic and changing peak load conditions, technology performance, technology costs, commodity prices, policy drivers and other factors play a role and would have to be modeled to ensure validation.

This also presents an opportunity for Duke to study the various benefits and limitations of its current modeling software and pursue products that accurately evaluate both the capacity and energy services provided by renewable resources. As more renewable resources are added to the MISO and PJM systems, Duke should be evaluating its system needs for all hours of the year – not just peak hours. The 2018 IRP portfolio optimization analysis was completed using a combination of the System Optimizer software and PROMOD.⁴⁶ It is unknown to CGA whether System Optimizer evaluates the system on an hourly basis, however, other utilities have started looking at sub-hourly operations. For example, Puget Sound Energy chose to use a combination AURORA and Plexos software in its IRP processes, highlighting the benefits of using Plexos to evaluate sub-hourly operational capabilities.⁴⁷ Such flexibility is exceptionally important for evaluating renewable resources that provide sub-hourly ramping capabilities. Appalachian Power recognized wind and solar’s energy contributions in its 2017 IRP, noting that renewable resources made a “fairly modest” capacity contribution, according to PJM’s Capacity Performance rules. In addition, it noted that wind energy, in particular, provided a significant volume of energy and

⁴⁶ Plan at 27.

⁴⁷ Puget Sound Energy, “2017 PSE Integrated Resource Plan,” at 3-12, available at <https://pse-irp.participate.online/>.

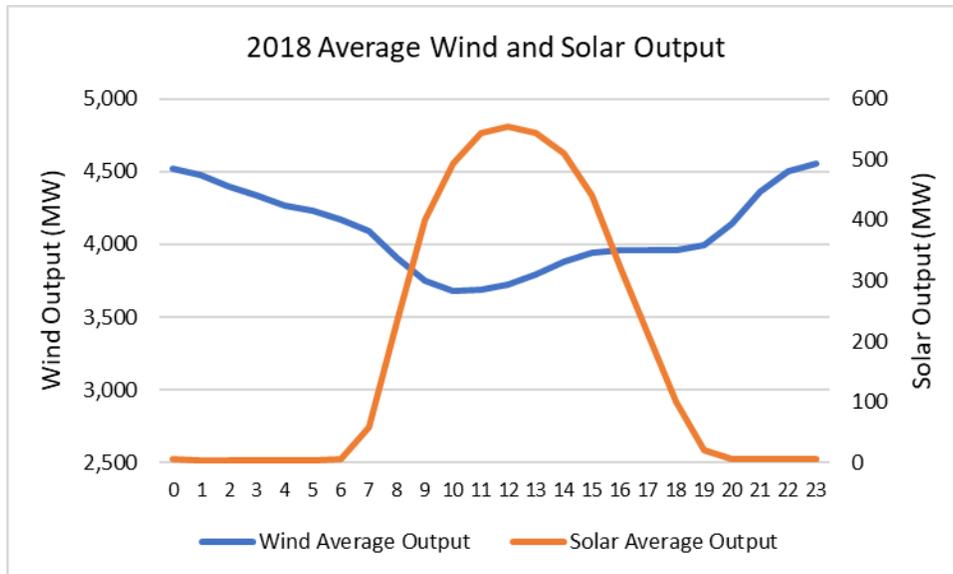
would help to lower customer costs and lower exposure to volatile energy markets.⁴⁸

Of course, a balanced renewable energy portfolio provides additional value. Duke would benefit from wind and solar energy's complementary production profiles, with seasonal and diurnal output patterns balancing particularly well. From a seasonal perspective, wind energy generation tends to be strongest in the winter, spring, and fall months; solar generation is strongest during the summer. On a diurnal basis, wind generation tends to be strongest at night; solar generation ramps up to its highest levels in the middle of the day. The chart below illustrates average daily wind output in MISO and PJM in 2018 as well as average daily solar output in PJM in 2018.⁴⁹ Over the course of 24 hours, wind generation complements solar generation, particularly in the late-night hours when solar generation ramps down. These output changes can be forecasted and planned well in advance as grid operators have the technology and experience necessary to forecast and prepare for hour-to-hour variability. In fact, today's weather forecasting technology makes changes in wind and solar energy output rather predictable.

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⁴⁸ Appalachian Power, Docket No. PUR-2017-00045, "Integrated Resource Planning Report to the Commonwealth of Virginia State Corporation Commission,," at ES-12 (May 1, 2017), available at: <http://www.scc.virginia.gov/docketsearch/DOCS/3%23%259011.PDF>.

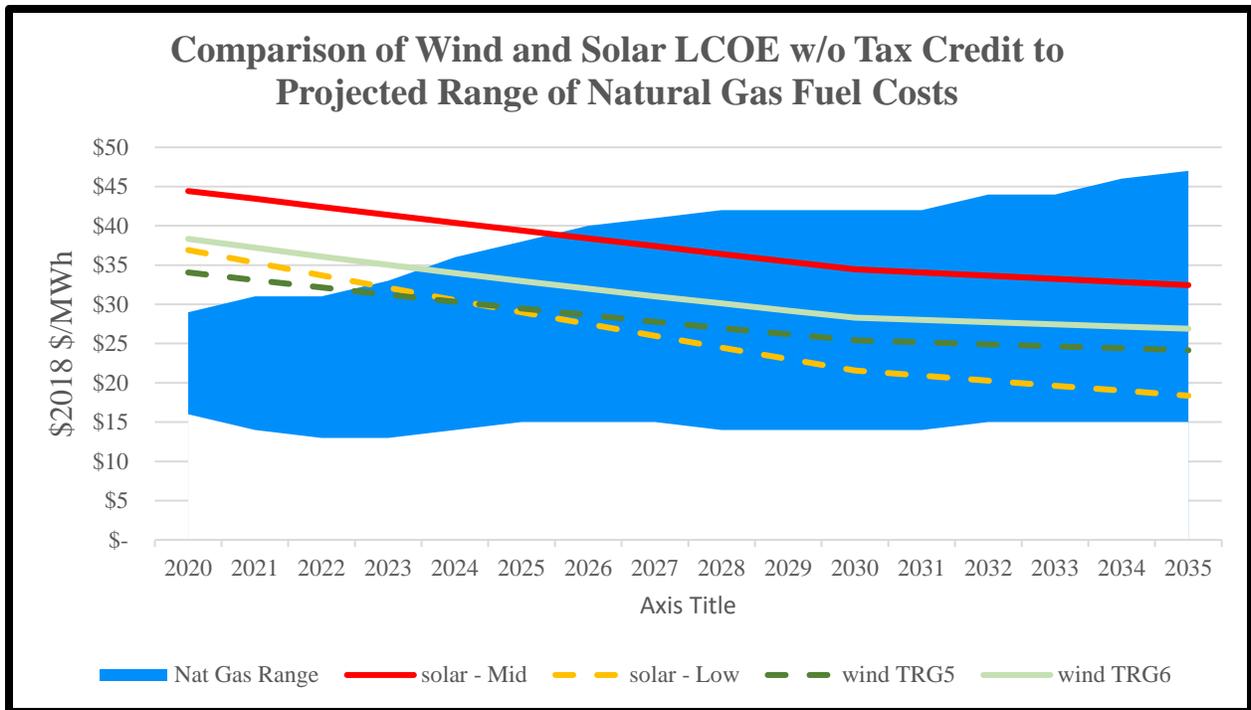
⁴⁹ PJM, Markets and Operations (accessed February 2019). https://dataminer2.pjm.com/feed/gen_by_fuel. Data derived from all 24-hour periods in 2018; *see also*, MISO, "Historical Hourly Wind Data." Accessed February 2019. <https://www.misoenergy.org/markets-and-operations/market-reports/#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3AHistorical%20Hourly%20Wind%2>



Weather patterns also tend to produce complementary wind and solar energy production profiles. Solar output is typically highest when a high-pressure system is present. High-pressure systems are marked by cloudless days and more intense periods of sunshine. Wind output is typically lower during these systems but improves in low-pressure systems with increased wind speeds and cloud cover. Duke should take advantage of wind and solar energy’s complementary production profiles by procuring a balanced mix of these resources.

In the long-term, renewable energy continues to provide portfolio diversity and to hedge against fuel price volatility. Utility-scale wind and solar prices have been competitive with new natural gas for several years. Even without the PTC, they can provide a hedge to fuel costs⁵⁰ for natural gas plants. Comparing NREL-ATB forecasted mid-level wind and solar LCOEs for TRGs in Indiana out to 2035 to EIAs latest projections for the fuel cost of natural gas-fired generation, shows the hedge value they provide to rising or uncertain natural gas plant operations.

⁵⁰ The range of natural gas fuel cost projections come from LBNL’s “Wind Technologies Market Report – 2018” at 62-63 (August 2019). That report used fuel projections from EIA’s Annual Energy Outlook 2019.



The forecasted wind LCOE declines over time because inflation reduces the contracts' fixed costs.

The hedge improves if NREL-ATB's low-level forecasted prices for wind and solar are used.

7. DUKE SHOULD OFFER A WELL-DESIGNED GREEN TARIFF PROGRAM

As identified in Section 1, customers in Indiana and across the country have made their commitment to renewable energy very clear, with a growing number of companies setting renewable energy and energy-related sustainability targets. Duke's overall portfolio should reflect this increasing customer preference for renewable energy.

Duke should also expand options to allow large customers to purchase renewable energy through a green tariff program. Since 2013, U.S. companies have purchased over 15 GW of renewable energy from offsite projects, procuring wind energy more than any other resource.³⁹ Most renewable energy purchases from offsite projects are facilitated through virtual PPAs or utility-offered green tariff programs. This reflects a growing preference for direct renewable energy purchases over taking the minimum action to purchase renewable energy credits ("REC").

Six corporate customers procured 478 MW of Indiana wind power capacity through the end of 2018 through PPAs alone. The following table summarizes those purchases:

Contracted	Capacity	Power Purchaser	Project Name	Project Developer	Year Announced
149.50		Amazon	Amazon Wind Farm (Fowler Ridge)	Pattern Energy Group, Inc.	2015
75.00		Cummins	Meadow Lake	EDP	2017
139.00		Facebook	Headwaters II	EDP	2018
5.00		Iron	Meadow Lake	EDP	2018
49.95		Nestlé	Meadow Lake	EDP	2018
60.00		Walmart	Headwaters II	EDP	2018

As of October 2018, there were no Indiana utilities offering green tariff programs.⁵¹ While Duke offers a GoGreen Indiana option for customers to purchase Green-E certified RECs,⁵² Duke could enhance options for customers by allowing eligible customers to buy a bundled renewable energy product from specific renewable energy projects. A green tariff program would allow customers to realize the benefits of a bundled product such as being able to enter into a long-term contract that hedges against future fuel price volatility.

The Corporate Renewable Energy Buyers’ Principles, signed by multiple Indiana companies, confirm customer interest in working with their local utilities “to design and develop

⁵¹ World Resources Institute, “Emerging Green Tariffs in U.S. Regulated Electricity Markets,” (October 2018), available at: https://wriorg.s3.amazonaws.com/s3fs-public/emerging-green-tariffs-in-us-regulated-electricity-markets_1.pdf?_ga=2.134860018.208984116.1549575612-548565371.1531225968.

⁵² See, “Duke Energy, Renewable Energy – Indiana” webpage available at: <https://www.duke-energy.com/home/products/renewable-energy/gogreen-energy>

innovative programs and products that meet our needs.”⁵³ These companies also prefer purchasing renewable energy from new projects “within reasonable proximity to their facilities,” specifically on their local electricity grid.”⁵⁴

Eligible customers have procured a total of 1,906 MW of renewable energy via green tariff programs to date, with an additional 950 MW currently under negotiation.⁵⁵ This represents significant recent interest, as 99% of the 1,906 MW were signed since the beginning of 2015 alone. General Motors, in particular, shared in its blueprint “Accelerating and Scaling Corporate Renewable Energy” that they view green tariff programs “as a significant part” of their renewable energy procurement strategy moving forward.⁵⁶ Duke should align with these corporate strategies by offering a green tariff program and procuring additional renewable energy in anticipation of this demand.

Duke should review green tariff designs in other states and survey customers to design a green tariff that considers the following components:

- offers bundled renewable energy products to customers⁵⁷;
- uses a transparent competitive market solicitation process⁵⁸;
- ensures that customers are charged a cost-based price (with market-based billing structure if possible)⁵⁹;

⁵³ Renewable Energy Buyers Alliance, “Corporate Renewable Energy Buyers’ Principles,” accessed December 2019. Available at: <http://buyersprinciples.org/principles/>.

⁵⁴ *Id.*

⁵⁵ World Resources Institute, “Grid Transformation: Green Tariff Deals,” accessed February 2019.

⁵⁶ General Motors, “Accelerating and Scaling Corporate Renewable Energy,” at 4 (2017).

⁵⁷ See e.g., Corporate Renewable Energy Buyers’ Principles, “The Principles,” available at: <http://buyersprinciples.org/principles>, discussing the benefits of bundled purchases over unbundled purchases of renewable energy credits.

⁵⁸ See e.g., National Renewable Energy Laboratory, “Procurement Options for New Renewable Electricity Supply.” (December 2011), available at: <http://www.nrel.gov/docs/fy12osti/52983.pdf>.

⁵⁹ See e.g., Omaha Public Power District, “Electric Rate Schedules and Service Regulations” at 44 (February 2019,; available at: <https://www.oppd.com/media/207840/oppd-rate-manual.pdf>; Virginia Electric and Power Company, “Schedule RG Renewable Generation Supply Service” (December 11, 2018), available at: <https://www.dominionenergy.com/library/domcom/media/large-business/renewable-energy-programs/schedule->

- provides options for customers to negotiate directly with third-party suppliers⁶⁰;
- provides flexible term options for customers; and
- allows for aggregation of multiple customers (or multiple accounts) in order to gain the benefits of economies of scale.⁶¹

Duke should review a variety of options, and provide enhanced opportunities for customers to access renewable generation options.

8. DUKE NEEDS TO CLARIFY THE CAP ON ANNUAL WIND AND SOLAR ADDITIONS

The Plan states that annual wind and solar capacity additions are capped at 250MW due to “practical constraints.”⁶² This cap seems very low. In another location in the Plan “practical constraints” is used in reference to modeling parameters within the System Optimizer, but it is unclear whether that is the constraint capping annual wind capacity additions.⁶³ Duke should clarify the “practical constraints” referenced in the Plan on page 59 before the asserted cap is accepted.

9. THE TIME TO PERMIT AND CONSTRUCT A PLANT SHOULD NOT BE CONFIDENTIAL INFORMATION

The time used for modeling permitting and construction of each unit type is reflected in Table V.1. on page 58 of the Plan. Duke has marked that table as confidential. Permitting and time of construction should not be considered confidential.

[rg/compliance-filing-schedule-rg.pdf?la=en](#).

⁶⁰ See e.g., Rocky Mountain Power, “Electric Service Schedule No. 32” (April 1, 2015), available at: https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/utah/rates/032_Service_From_Renewable_Energy_Facilities.pdf.

⁶¹ See e.g., Georgia Power “Commercial & Industrial REDI Schedule: CIR-1.” (Effective January 2019), available at: <https://www.georgiapower.com/content/dam/georgia-power/pdfs/business-pdfs/rates-schedules/ci-redi-tariff.pdf>.

⁶² Plan at 59.

⁶³ Plan at 78.

10. CONCLUSION

WHEREFORE, CGA requests that the Commission and Duke consider the information provided and adopt the recommendations contained herein.

Respectfully Submitted,

/s/

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