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A Cost-Effective, Cleaner Energy Portfolio for Duke Energy Indiana Customers

Public Version

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1 Joint Commenters' EnCompass Modeling Runs

Since 2019, EFG has conducted numerous EnCompass simulations for proceedings involving integrated resource plans ("IRPs") and certificates of public convenience and necessity ("CPCN"). Those simulations typically involve a review of the utility's EnCompass database; changes to its assumptions to correct errors, update information, and/or make changes that we would consider more reasonable; and then re-simulation to develop an alternative portfolio of resources. We employed the same approach to this work and used Duke Energy Indiana's ("Duke") EnCompass database prepared for this IRP. On behalf of our clients, Citizens Action Coalition of Indiana ("CAC"), Earthjustice, and Vote Solar, we developed a plan that added only incremental renewable, storage, and Demand Side Management ("DSM") resources as an alternative to Duke's Preferred Portfolio (in addition to allowing conversion of the Edwardsport Integrated Gasification Combined Cycle plant to natural gas).

Our modeling approach examined two portfolios under Duke's CO_2 price scenario:

1) An alternative expansion plan with all renewable, battery storage, energy efficiency, and demand response additions, in addition to the Edwardsport conversion (referred to as the "CAC Preferred Plan"), and

2) A version of Duke's Preferred Plan with the modeling changes made by EFG to fairly compare it with the CAC Preferred Plan (referred to as the "Duke Revised Preferred Plan").

Our findings, described in this report, are that a portfolio of renewable, storage, energy efficiency, and demand response resources, along with an earlier natural gas conversion date for the Edwardsport Integrated Gasification Combined Cycle ("IGCC") plant is cheaper and produces lower CO_2 emissions when compared to the Duke Revised Preferred Plan, which adds a new, capital intensive combined cycle ("CC") unit in 2027 and does not allow the model to economically select conversion of Edwardsport until 2035.

1.1 Modeling Methodology

Capacity expansion modeling involves utilizing an optimization engine to minimize system costs including the costs of new and existing resources and a simplified[1] simulation of existing and new resource unit commitment and dispatch. Figure 1, below, highlights the process that Duke used to create its optimized portfolios. In the first step, modeling inputs[2] such as new resource parameters, including new resource options and their associated costs, are input into EnCompass along with Duke's

[1] In order for the model to be able to reach a solution and produce an expansion plan, the "problem size" must be manageable. One way to help manage the problem size is to only simulate a few hours, such as two "typical" days per month in the capacity expansion modeling step.

[2] Other inputs include load forecast, fuel prices, market power prices, resource constraints, and emission constraints.

existing supply and demand side resources. EnCompass will develop an optimized portfolio based on those modeling inputs subject to constraints such as the planning reserve margin ("PRM"). Because there are so many potential feasible plan combinations, the model will seek to develop a least cost portfolio within a specified cost margin or "gap." For Duke's hybrid portfolios and for stakeholder portfolios, Duke performed *some* capacity expansion optimization but also forced certain resource builds into the model.

In the second step, the capacity expansion plan from step one is then simulated chronologically across all 8,760 hours of each year in the planning period to refine the production cost component of the total revenue requirement. In Duke's case, fixed O&M and capital expenditures ("CAPEX") at its existing coal units were added to the revenue requirements in step three, which occurred ***outside*** of EnCompass.

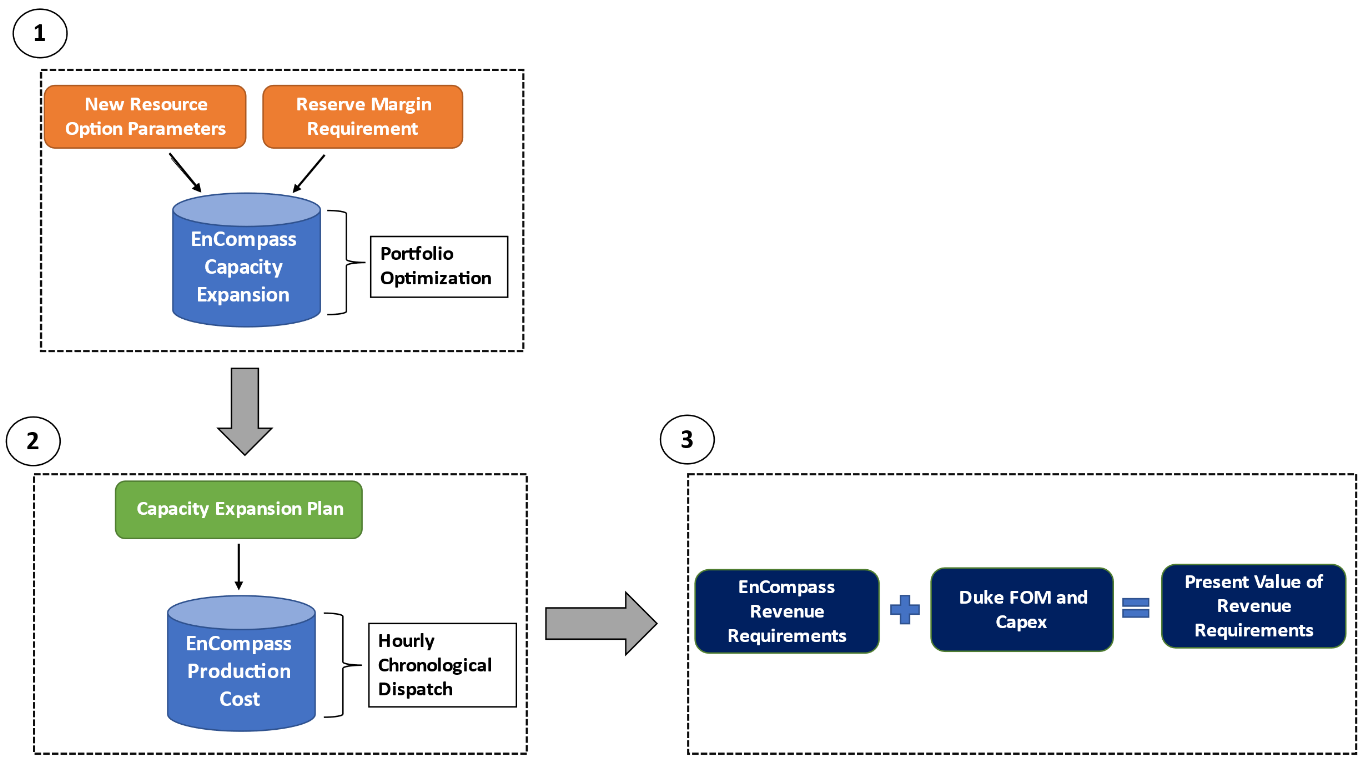

Figure 1. EnCompass Modeling and Out of Model Adjustment Process Used by Duke

The following sections will discuss the modeling changes that EFG made. In order to put Duke's Preferred Plan in comparable terms to the CAC Preferred Plan, it was necessary to rerun Duke's Preferred Plan with our changes. For example, we used a different discount rate than Duke used to calculate the present value of revenue requirements ("PVRR"); without changing that assumption in Duke's plan the two plans would not be cost comparable. We fixed the supply side resources added in Duke's Preferred Plan but then allowed the model to determine if additional resources should be added to the plan and to recalculate system costs to make what we call Duke's Revised Preferred Plan.

1.2 EnCompass Modeling Input Changes for CAC Portfolios

The following sections describe the changes that were made to Duke's EnCompass modeling database to develop the CAC Preferred Plan and the Duke Revised Preferred Plan.

1.2.1 Renewables and Storage Costs

We had several concerns about Duke's renewables and battery storage resources costs including:

1. Use of short term and long-term inflation rates to reflect capital cost reductions;
2. Failure to monetize the Investment Tax Credit ("ITC") by applying it as a reduction in costs for the first year of an eligible project; and
3. Using a weighted average cost of capital ("WACC") of [redacted]% to develop the fixed charge rates ("FCR") which is inconsistent with the Company's authorized WACC at the time.[3]

Regarding the first concern, Duke's assumptions for the near-term capital cost of solar, wind, and storage resources came from Navigant.[4] Duke then used a blended forecast from Navigant and the Energy Information Administration ("EIA") to project capital costs between 2030 to 2050. One of the assumptions that Duke makes when modeling renewable and storage resources is that there are different expected cost rates of change depending on the forecast period. Duke applies what it calls "ST Capital Cost Inflation" and "LT Capital Cost Inflation" to these resources. Duke stated that, "The ST Capital Cost Inflation is the expected cost rate of change for each technology over the first 10 years of the forecast. The LT Capital Cost Inflation is the expected cost rate of change of each technology from the end of the ST period through the end of the forecast (2036)."[5]

We found the rationale for this methodology to be unclear, and the approach itself was not readily replicable. Instead of using its opaque methodology for new renewable and storage resource costs, we used a data source that many other utilities have used: the 2021 National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") Moderate Cost curves for solar, wind, and battery storage resources. The NREL ATB is a reputable, widely used, and public source of information for capital costs of supply side resources.

Unlike Duke, we assumed that solar resources would be able to take advantage of the ITC as a reduction in the capital cost for the first year of the project instead of assuming normalization, which spreads the ITC benefits over the life of the project. Duke, on the other hand, assumed that the projects would

[3] IURC Cause No. 42061 ECR 36 is Duke Energy Indiana's last approved capital structure and rate of return (data as of June 2021).

[4] Duke Informal Discovery Confidential Attachment SC 4.1-A.

[5] Duke Informal Discovery Response to CAC 6.1A.

receive a tax equity discount to the Fixed Charge Rate ("FCR") to reflect the use of a tax-equity partnership to monetize the ITC, but then the ITC would be normalized.[6] Duke's approach does not appear to appropriately capture the impact of monetization.

One other change we made when developing these costs is to change the discount rate which is pegged to Duke's WACC. The workbooks Duke provided in discovery used a WACC of [redacted]% to develop the FCRs applied to the renewable and storage resources. In the energy efficiency bundle workbook[7] from Duke, we noticed that Duke used a significantly different WACC. Given Duke's most recently approved capital structure as of June 2021, we decided to modify the supply-side cost calculations to use the discount rate of 7.1% to develop the FCRs applied to the solar, wind, and battery storage resource costs. This is slightly lower than the authorized rate of 7.17% because there was some confusion about where to find the most recent authorized structure and in the time it took to identify the most recent capital structure we needed to set up our capital cost assumptions and started the modeling process.

1.2.2 Combined Cycle Capital Cost

In its Preferred Plan, Duke selected a new 1,221 MW combined cycle ("CC") that would come online in 2027. The underlying capital cost for this CC is [redacted]/kW,[8] which is significantly less than the combined cycle cost we typically see modeled in IRPs and also significantly less than two publicly available sources of data. First, we looked at the cost and MW size for seven CC projects of a comparable size in neighboring states. The weighted average cost of the seven CC projects that are greater than 1,000 MW is $955/kW as shown below in Table 1. We also evaluated Duke's capital cost assumption against what was reported in the EIA's Annual Energy Outlook ("AEO") for 2022. Duke's capital cost is also much lower than the $1,201/kW presented in the AEO.[9] Thus, we updated the capital cost for the 1,221 MW CC in Duke's Preferred Plan to reflect the more modest change from [redacted] up to the $955/kW weighted cost average from the CC projects in neighboring states.

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[6] Informal Discovery CAC Confidential Attachments CAC 6.18.

[7] Informal Discovery CAC Confidential Attachments CAC 6.18.

[8] Duke Energy Indiana 2021 IRP, Figure V.1, page 88.

[9] Energy Information Administration. Annual Energy Outlook 2022. Cost and Performance Characteristics of New Generating Technologies. Retrieved from https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

Table 1. CC Project Costs[10]

Facility	Rating (MW)	Cost	Cost per kW
Cadiz Combined Cycle Plant (Harrison County Industrial Park)	1,050	$ 987,000	940
Blue Water Energy Center (Belle River Combined Cycle Plant)	1,146	$ 1,000,000	873
Indeck Niles Energy Center	1,174	$ 1,103,936	940
Jackson Generation Energy Center	1,200	$ 1,224,000	1020
CPV Three Rivers Energy Center	1,250	$ 1,312,500	1050
Cornerstone Energy Center Project	1,800	$ 1,836,000	1020
Guernsey Power Station	1,875	$ 1,600,000	853
Weighted Average of Projects over 1,000 MW			$ 955

Similar to the renewable and storage resources, we also used a WACC of [redacted]% to develop the FCR applied to the capital cost of the CC to develop the levelized costs to go into EnCompass as a modeling input.

1.2.3 Adding Long Duration Battery Storage Resources and Other "ZELFR" Resources

We developed inputs for 8- and 10-hour Li-Ion battery storage based on the NREL ATB moderate case. We also used information from a report published by the LDES Council and McKinsey & Company to develop inputs to model multi-day storage. In its modeling, Duke included resources referred to as Zero-Emitting Load-Following Resources ("ZELFR") to represent "new technologies that have not yet reached commercialization status."[11] In regard to the technologies that fall under this ZELFR category, Duke said:[12]

> *Duke Energy is evaluating several generation technologies that are considered pre-commercial to meet the ZELFR need. Technologies considered typically fall under the broad categories of advanced nuclear, advanced renewables, advanced transmission and distribution, biofuels, carbon capture utilization and storage (CCUS), fuel cells, hydrogen, long duration energy storage, and supercritical CO2 Brayton Cycle.*

Yet, the only "ZELFR" technologies actually included in Duke's modeling are the advanced nuclear resources. Most surprising was that Duke did not model any battery storage with durations longer than 4 hours in EnCompass. Given the technological advancements of battery storage and the fact that longer durations are already available, we developed several longer duration battery storage options to be offered to the model as a new resource option. The 8- and 10-hour options were based on NREL data,

[10] Project Costs from S&P Global.

[11] Duke Energy Indiana 2021 IRP, page 177.

[12] Duke Energy Indiana 2021 IRP, page 177.

and assumptions for multi-day storage resource were developed using a Long Duration Energy Storage Council and McKinsey & Company Report.[13]

We also removed the option of selecting the Small Nuclear Reactor ("SMR") projects because of concerns about the ability and lengthen of time needed to commercialize and operate this technology.

1.2.4 Solar Hybrids

We modified the manner in which Duke modeled solar hybrid resources. In its modeling, Duke assumed that the solar and battery resources would be paired together for the entire project life, an assumption which is far more strict than is required to be eligible for the ITC. The ITC merely requires that the battery be charged exclusively from the solar resource for the first five years of its life to receive the full ITC. Duke also developed an hourly profile that entirely fixed the operation of the solar and battery storage. Instead of using this highly constrained approach, we set up unique resources to capture the solar and the battery components of the hybrid project separately. This means that in EnCompass, the resources are paired together for the first five years of the project life to ensure that the requirements of the ITC are met, but afterwards the battery can operate independently of solar production so long as the limits of the inverters they share are observed. We believe that this method allows for better and more accurate modeling of battery storage operation.

1.2.5 Partial Unit Selection

We also allowed the model to select partial amounts of certain resource types, i.e., any amount greater than zero. Modifying Duke's database so that hybrid projects were properly simulated increased our problem size and made run times a challenge. In order to help solve this issue, we allowed the model to select partial units of all battery storage resources modeled across the entire planning period in recognition that these systems are highly modular. We also allowed solar and wind resources to be added in partial units starting in 2035. Relaxing the constraint that the model must take these resources in whole units throughout the planning period helped make the problem size more manageable with minimal impact to the fidelity of the results.

1.2.6 Supply Side Resource Accreditation

For several years, the Midcontinent Independent System Operator ("MISO") has been working on a redesign of its resource adequacy ("RA") construct. MISO's proposal now before FERC would result in four seasonal planning reserve margins and corresponding seasonal accredited capacity values for supply-side resources. However, Duke only applied a winter accreditation[14] to solar resources - 0%

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[13] Long Duration Energy Storage for a Renewable Grid. (November 2021). Retrieved from https://www.mckinsey.com/~/media/mckinsey/business%20functions/sustainability/our%20insights/net%20zero%20power%20long%20duration%20energy%20storage%20for%20a%20renewable%20grid/net-zero-power-long-duration-energy-storage-for-a-renewable-grid.pdf

[14] Since Duke modeled a two season construct, the summer months are considered to be the beginning of April to the end of September, and the winter months are the beginning of October to the end of March.

capacity credit – but a static, year round 13% capacity credit for wind. And Duke did not attempt to account for how the accreditation of thermal units would be altered under the accreditation changes that accompany the proposed move to a seasonal RA construct. This new thermal accreditation methodology in MISO's proposal is called seasonal accredited capacity ("SAC").

Since Duke based all of its modeling for this IRP on its selective interpretation of MISO's proposed changes, we made several changes to try to better reflect the impacts of MISO's proposal assuming it is approved by the Federal Energy Regulatory Commission ("FERC").[15] We applied a 5%[16] capacity credit for solar resources in the winter months based on a report from MISO.

Though unrelated to the move to a seasonal construct, we also used the MISO Futures Modeling to develop a declining capacity credit assumption, shown in Figure 2, for the summer months to better reflect information from MISO.[17]

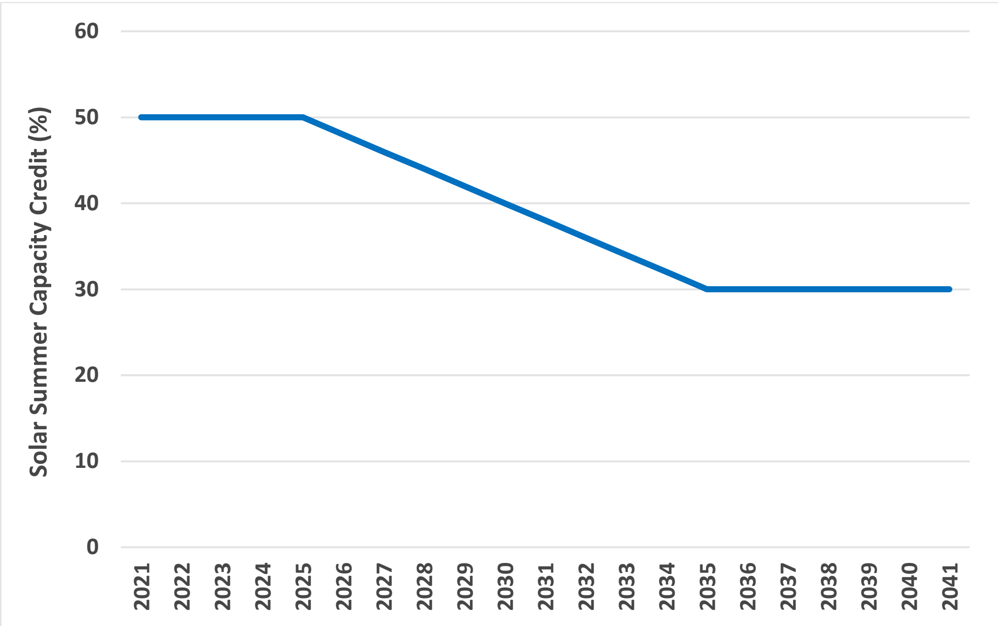

Figure 2. MISO Futures Solar Capacity Credit (%)[18]

MISO has suggested that there will be accreditation benefits for wind resources in the winter months when wind typically produces more energy and therefore will have a higher accredited value. One of

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[15] See FERC Docket No. ER22-495.

[16] RAN Renewable Impact Analysis Tariff Review Workshop. September 8, 2021.

[17] RAN Renewable Impact Analysis Tariff Review Workshop. September 8, 2021.

[18] MISO Futures Report. April 2021. Retrieved from https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf.

MISO's analyses presented to its Resource Adequacy Subcommittee indicated that wind would have a winter capacity credit of 28.6%.[19] In an effort to be more conservative than the MISO report, we modeled a winter capacity credit of 25% for wind resources rather than Duke's 13% assumption.

For battery storage resources, Duke modeled a summer and winter capacity credit of 80%. We have reviewed numerous IRPs filed by utilities operating in the MISO footprint, and most of the utilities have modeled a capacity credit between 90-100% for battery storage resources. In light of what we have seen in other IRPs and without further documentation for Duke for the rationale of choosing 80%, we changed the battery storage capacity credit to 90%.

Table 2 provides a summary of the MISO RA construct assumptions included in the EFG modeling.

Table 2. Summer and Winter Resource Accreditation in CAC vs. Duke Runs (%)

	Winter		Summer	
	CAC	**Duke**	**CAC**	**Duke**
Solar	5%	0%	MISO Futures	Varies by penetration
Wind	25%	13%	13%	13%
Battery Storage	90%	80%	90%	80%

In an effort to ensure Duke's proposed MISO RA Construct methodology did not bias the modeling against renewable resources, we applied the proposed SAC methodology to Duke's thermal units. That methodology includes:

1. Identify real-time offered capacity during non-tight operating hours accounting for excluded events such as planned outages;
2. Identify real-time offered capacity during tight margin hours accounting for excluded events such as planned outages;
3. Apply MISO's proposed phase weighting of these different tiers of resource availabilities; and
4. Apply the UCAP/ISAC (Unforced Capacity/Intermediate Seasonal Accredited Capacity) ratio to each unit's accredited value.

Table 3 shows the comparison of the accredited or firm capacity for some of Duke's thermal power plants as modeled by Duke to the anticipated SAC value of these generators. The values reported under the column labeled "SAC" show the accredited or firm capacity value of Duke's thermal plants when MISO's SAC methodology is used. On a plant basis, the SAC methodology results in a lower accredited value for these four plants, but also for other Duke units.

[19] RAN Renewable Impact Analysis Tariff Review Workshop. September 8, 2021.

Table 3. Thermal Plant Summer Accredited Capacity Comparison for 2023 (MW)

Plant	Duke	SAC	Difference
Gibson	2,376	2,265	-110
Wheatland	431	269	-162
Madison	549	476	-73
Vermillion	339	239	-101

1.2.7 Resource Constraints

We also applied different constraints on wind and solar builds and the timing of when new thermal resources could be selected. Duke's modeling assumed that certain resources such as new combined cycle units could come online as early as 2023. Given that there are just six months until 2023 and only twelve months at the time the IRP was filed, we updated these dates in the model. Since Duke received numerous bids for solar projects that could be online in 2024 in response to the Request for Information ("RFI"),[20] we assumed that new solar and battery storage resources could be added starting in 2024. In order to acknowledge some of the supply chain and other impacts that have recently been observed, we modeled an annual constraint on solar that starts at 500 MW per year in 2024 and 2025, then ramps up to 750 MW in 2026 and 2027, and then reaches 1,000 MW in 2028. We assumed that the 1,000 MW annual limit applied between 2028 and the end of the planning period at 2050 in the capacity expansion step. We also allowed the model to start selecting new wind resources starting in 2025 and applied a 500 MW annual constraint throughout the entire planning period.

We assumed that new thermal builds could start in 2025 in the Duke Revised Preferred Plan.

1.2.8 Coal Retirement Dates

The CAC Preferred Plan assumes the same coal retirement dates in Duke's Preferred Plan as are shown in Table 4 except for the date at which Edwardsport converts to natural gas. Duke's Preferred Plan fixed Edwardsport's conversion to gas in 2035, but we allowed EnCompass to optimize the decision of when to convert Edwardsport in the CAC Preferred Plan. In Duke's optimized portfolios, Duke allowed EnCompass to choose to convert Edwardsport as early as 2023, and we retained that same assumption in the modeling of the CAC Preferred Plan.

[20] Informal Discovery Sierra Club Confidential Attachment SC 4.1-C.

Table 4. Coal Retirements in Duke's Preferred Plan

Units	Duke Preferred
Cayuga 1 & 2	2026
Edwardsport Conversion*	2035
Gibson 1 & 2	2034
Gibson 3	2028
Gibson 4	2028
Gibson 5	2024

We did not try to reoptimize Duke's unit retirement dates because we had no way to adjust the fixed O&M and CAPEX streams to new dates. Our separate report on our review of Duke's IRP explains why it was not possible to do so.

1.2.9 Demand Side Management

Our review of the underlying workbooks to develop the $/MWh levelized cost of the energy efficiency bundles modeled by Duke indicated that Duke did not include the correct bundle costs in EnCompass. Duke developed adjusted energy efficiency bundle costs that accounted for program overhead, shareholder incentives, and avoided transmission and distribution ("T&D") costs. We updated the costs in EnCompass to reflect these adjusted bundle costs since they were materially lower than what Duke had modeled. Table 5 shows the comparison between the energy efficiency $/MWh costs modeled by Duke in EnCompass with the actual cost of the energy efficiency bundles when the adjustments for administrative costs, shareholder incentives, and the avoided T&D benefits are included. The Duke Adjusted costs are those that we included in our EnCompass modeling runs.

Table 5. **Duke Unadjusted and Adjusted Energy Efficiency Bundle Cost**

EE Bundle	Duke EE Scenario	Duke Modeled	Duke Adjusted[21]
2024 - 2026 Bundles	Expanded Measure	$[redacted]	$[redacted]
	Expanded Measure + Higher Avoided Cost	$[redacted]	$[redacted]
2027 – 2034 Bundles	Expanded Measure	$[redacted]	$[redacted]
	Expanded Measure + Higher Avoided Cost	$[redacted]	$[redacted]
2035 – 2042 Bundles	Expanded Measure	$[redacted]	$[redacted]
	Expanded Measure + Higher Avoided Cost	$[redacted]	$[redacted]
2043 – 2050 Bundles	Expanded Measure	$[redacted]	$[redacted]
	Expanded Measure + Higher Avoided Cost	$[redacted]	$[redacted]

We also assumed that the CAC Preferred Plan included the Expanded Measure + Higher Avoided Cost bundles, as well as all new, modeled demand response resources. The Duke Revised Preferred Plan continued to optimally select these energy efficiency bundles and demand response resources.

1.2.10 MISO Market Interaction

Many of Duke's modeling runs assumed that the transfer limit on sales and purchases with MISO was [redacted] MWs in any given hour. For our modeling, we applied a 20% limit to purchases or sales which equated to an import or export limit of [redacted] MWs in any given hour.

1.2.11 Capacity Power Purchase Agreements ("PPAs")

In the EnCompass model, Duke allowed capacity purchases during a single year. This resource, "Capacity PPAs," was available for selection in increments up to 500 MW between 2021 and 2023. Because of a projected near term deficiency in capacity that would be very difficult to solve with new resource builds, our modeling assumed that these capacity PPAs would be available up until 2025 and that partial units could be selected. Since we assumed no new supply side resources could be added in 2023, we allowed for higher amounts of the capacity PPAs in 2023 to offer an option to the model to handle the 2023 capacity deficit.

1.3 CAC Preferred Plan and Duke Revised Preferred Plan

In order to develop a version of Duke's Preferred Plan that could be comparable on a cost basis to the CAC Preferred Plan, we created a Duke Revised Preferred Plan. This plan assumed that all of the new supply side resource builds from Duke's Preferred Plan were fixed, and then we allowed the model to optimally select additional resources. Since Duke's Preferred Plan appeared to be developed under

[21] Duke's Confidential Attachments to CAC Informal Discovery 6.18.

Duke's CO_2 Price Scenario, we ran the CAC Preferred Plan and the Duke Revised Preferred Plan under the CO_2 Price Scenario as well. Table 6 provides a summary of the modeling changes that were applied to the CAC Preferred Plan and the Duke Revised Preferred Plan.

Table 6. Summary of Modeling Changes

Modeling Input Changes	CAC Preferred	Duke Revised Preferred
Renewable and Battery Storage Costs (NREL ATB)	✓	✓
Capital Cost of CC	N/A	✓
No new thermal resources allowed	✓	-
New thermal builds start in 2025	N/A	✓
Annual solar and wind constraints	✓	✓
Include 6 and 8 Hour Li-Ion Battery Storage	✓	✓
Include Multi-Day Storage (Conservative Cost)	✓	✓
Solar Hybrid Resources	✓	✓
Remove SMR as selectable resource	✓	✓
Partial unit for all battery storage resources	✓	✓
Partial unit for all resources after 2035	✓	✓
Winter accreditation for wind	✓	✓
5% accreditation for solar in winter	✓	✓
MISO Futures accreditation for solar in summer	✓	✓
SAC methodology for thermal resources	✓	✓
Battery storage accredited at 90%	✓	✓
Optimize Edwardsport conversion	✓	-
Updated EE bundle costs	✓	✓
Include higher EE savings and new DR as fixed resources	✓	-
Purchase limit set to [redacted] MW per hour	✓	✓
Sales limit set to [redacted] MW per hour	✓	✓
Offer Capacity PPAs until 2025	✓	✓
Increase Capacity PPA limit	✓	✓
Allow partial selection of Capacity PPAs	✓	✓

2 EnCompass Modeling Results

The following sections will discuss the EnCompass modeling results for the CAC Preferred Plan and the Duke Revised Preferred Plan, which include the capacity expansion plans, present value of revenue requirements ("PVRR"), and CO_2 emissions.

2.1 Capacity Expansion Portfolio Results

The EFG modeling runs included the changes made to Duke's EnCompass database as discussed in Section 1.2 of this report. For the Duke Revised Preferred Plan, we fixed in the supply side resources that were in Duke's Preferred Plan as filed with the IRP, but we did allow the model to optimally select additional resources given the modeling changes that we made. Figure 3 shows the annual capacity expansion plan for the Duke Revised Preferred Plan. In certain years, the model did optimally select additional resources to add to the capacity expansion plan in addition to the resources that were included in Duke's as-filed Preferred Plan. For instance, our Duke Revised Preferred Plan has some standalone battery storage added in 2029, 2036, and 2041, whereas Duke's Preferred Plan presented in the IRP never added any standalone battery storage. This is likely a product both of our changes to Duke's battery storage inputs, but also the change in the accredited value of its thermal units.

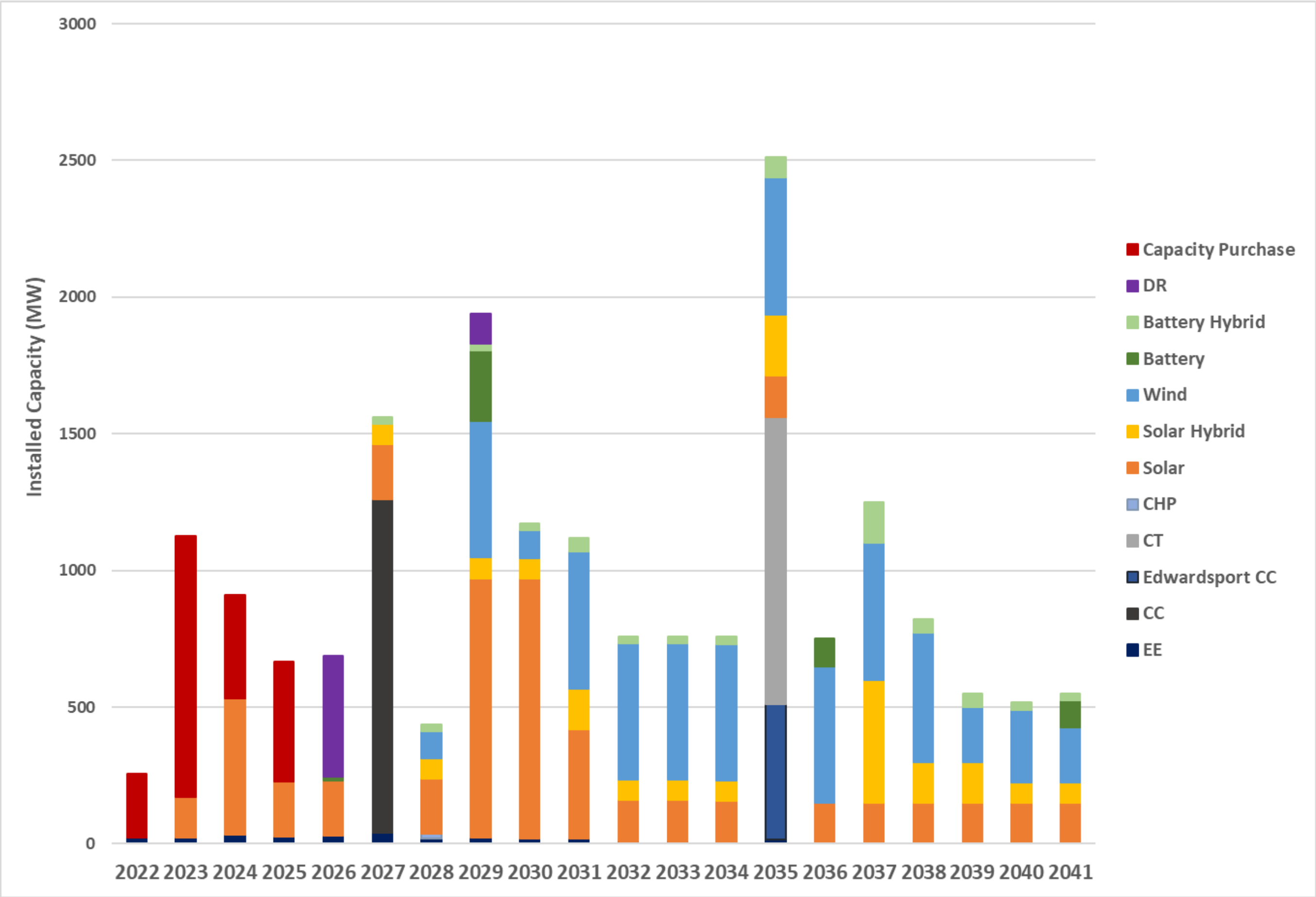


Figure 3. CAC's Duke Revised Preferred Expansion Plan[22]

Figure 4 shows the annual capacity expansion plan for the CAC Preferred Plan. Two of the main differences between the Duke Revised Preferred Plan and the CAC Preferred Plan are the replacement of new thermal builds with renewables and storage, and an earlier conversion date of Edwardsport to natural gas. Instead of the CC in Duke's Revised Preferred Plan, the model adds a combination of solar, solar hybrids, wind, and battery storage capacity in the CAC Preferred Plan. In addition, EnCompass also chose to convert Edwardsport at the earliest date available in the model, which is 2023. The CAC Preferred Plan also includes additional demand response resources in 2024 along with the larger Expanded Measures + Avoided Cost energy efficiency bundles.

[22] Solar hybrid represents the solar portion of the hybrid project, and battery hybrid represents the battery portion of the hybrid project. Note that the Edwardsport CC is not a new capacity resource, but merely represents the change in capacity that occurs from converting to unit to operate only on gas.

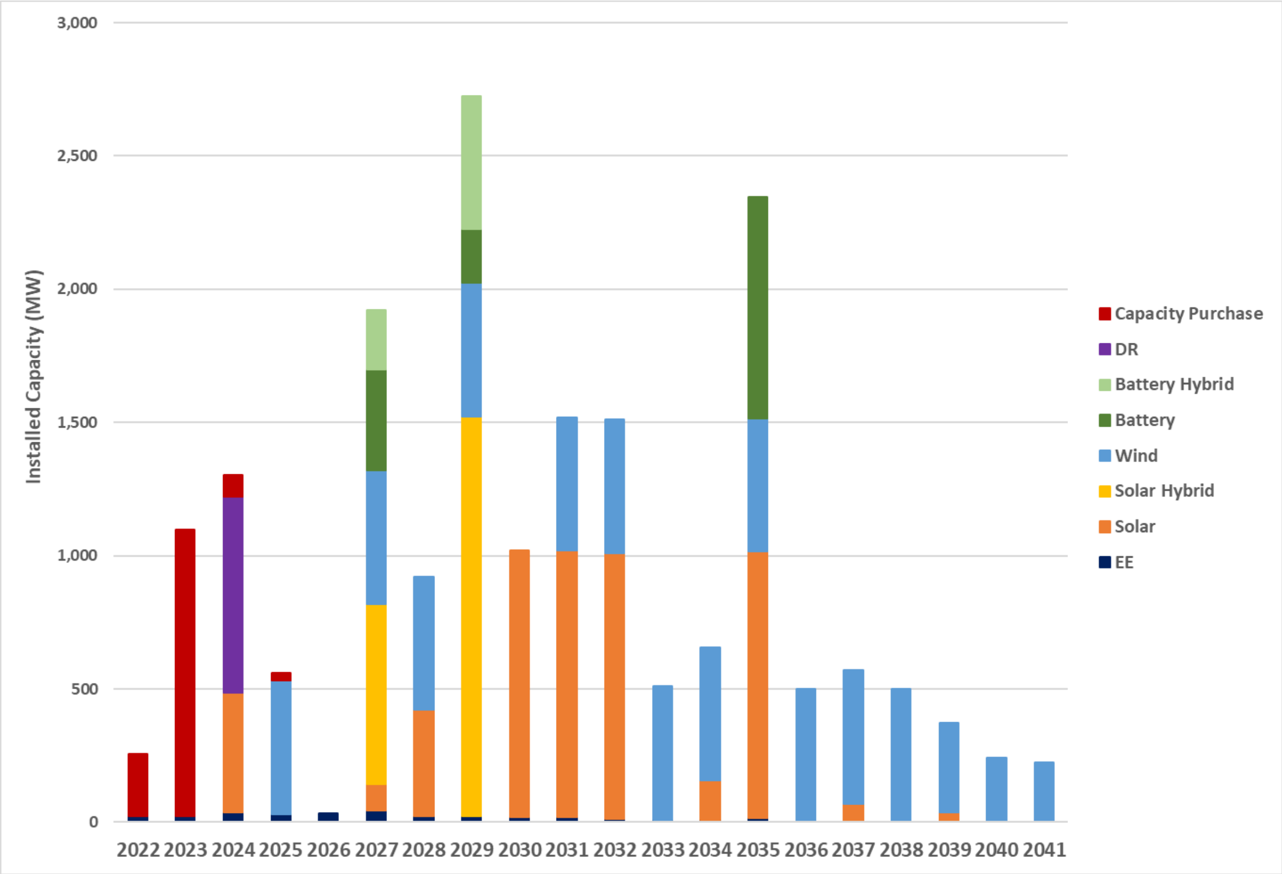
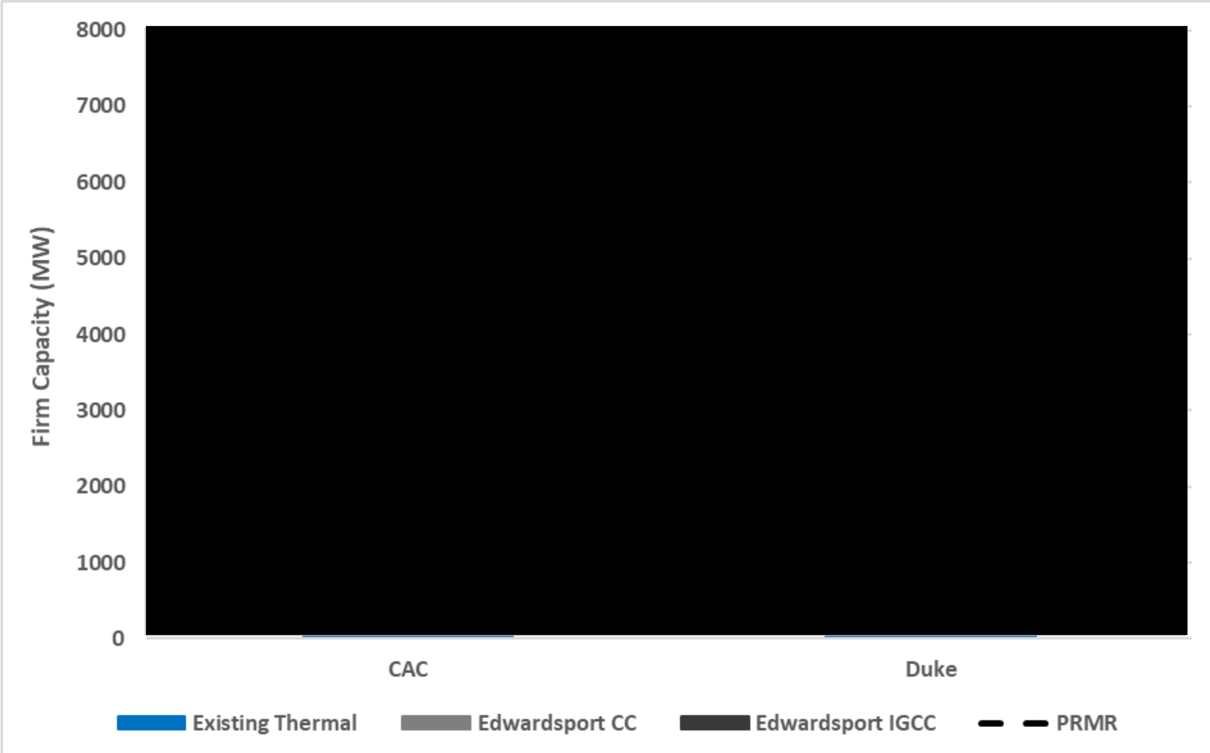


Figure 4. The CAC Preferred Expansion Plan

One of the modeling changes applied to both portfolios is the ability for the model to select higher amounts of capacity purchases in the 2022 to 2025 timeframe. When the SAC accreditation methodology was applied to Duke's thermal units, the lower accredited value of the thermal resources further widened the gap between the peak demand and the total firm capacity of Duke's resources. This gap was especially exacerbated in 2023 when Duke anticipates a spike in the peak demand from the addition of new wholesale customers.

Figure 5, below, shows the comparison of the firm or accredited capacity of Duke's existing thermal generation, along with the values for Edwardsport converted to a CC against the planning reserve margin requirement ("PRMR") in 2023. The CAC Preferred Plan reflects the SAC accreditation methodology for Duke's existing thermal units while the column labeled "Duke" reflects how Duke modeled the thermal resource accreditation in its IRP, which does not take the SAC methodology into account. The application of the SAC methodology in the EFG modeling results in a larger gap between Duke's firm capacity and PRMR in 2023 which causes the need for more capacity in both plans.



Confidential **Figure 5. 2023 Summer Accredited Capacity Comparison (MW)**

2.2 Present Value of Revenue Requirement ("PVRR") Results

The EnCompass-developed revenue requirements ("PVRR") are then added to the fixed O&M and CAPEX of the coal plants. Table 7, below, shows the comparison of the EnCompass PVRR, fixed O&M, CAPEX, and final PVRR for the CAC Preferred Plan and the Duke Revised Preferred Plan under Duke's CO_2 price scenario. ***The CAC Preferred Plan is 2.4% cheaper than the Duke Revised Preferred Plan.***

Table 7. PVRR Comparison ($000)

Portfolio	EnCompass PVRR	Fixed O&M	CAPEX	PVRR
CAC Preferred Plan	$18,819,020	$[redacted]	$[redacted]	**$20,155,025**
Duke Revised Preferred Plan	$18,363,070	$[redacted]	$[redacted]	**$20,642,558**

2.2.1 Fixed O&M and Ongoing CAPEX

In the IRP, Duke gives the steps involved in determining the fixed O&M and ongoing CAPEX of its coal units. Yet, for the production cost modeling runs, Duke removes all fixed O&M and ongoing CAPEX from the EnCompass model and uses an in-house tool to develop cost trajectories based on the retirement dates and how often the units are projected to operate. Duke then takes those new cost streams and adds them as an out-of-model post processing adjustment to the revenue requirements reported by EnCompass. Since we are modeling the same coal retirement dates as Duke, except for when Edwardsport converts to natural gas, we had to use these cost streams Duke developed for the Preferred Plan under the CO_2 scenario, with the exception of Edwardsport because of its economically selected conversion in 2023 under the CAC Preferred Plan.

The decision of whether to convert Edwardsport now or in 2035 as Duke has included in its Preferred Plan has significant implications for costs to customers. Table 8, below, shows the net present value ("NPV") between 2021 to 2034 of the fixed O&M and ongoing CAPEX to continue to operate Edwardsport until a conversion in 2035.

Confidential Table 8. Edwardsport Fixed O&M and CAPEX (2021- 2041) under Duke Preferred Plan with CO_2 ($000)[23]

	Fixed O&M	CAPEX	Total
NPV	$[redacted]	$[redacted]	$[redacted]

2.2.2 Value of Flexibility

We have seen a number of utilities try to capture the value of flexible supply-side resources in their IRPs. It is difficult to do this within the IRP optimization itself, because the market price strip often does not capture the stochasticity of market prices. NIPSCO approached this problem in its 2021 IRP with an assessment of the potential value streams that resources like battery storage, solar hybrids, CTs, and CCs can provide from participation in non-day-ahead energy markets such as ancillary service markets.

[23] Duke's Confidential Attachments to Informal Discovery CAC 3.1A

In order to perform this analysis, NIPSCO's IRP consultant, Charles Rivers Associates ("CRA"), utilized its proprietary Energy Storage Operations ("ESOP") model to determine the value streams. NIPSCO described the approach as follows:

> *Since the core Aurora market and portfolio model is fundamentally based on a day-ahead simulation, NIPSCO has performed additional analysis to estimate the incremental value streams that flexible resources can achieve by participating in markets beyond day-ahead energy. To do this, CRA employed its proprietary ESOP model, an optimization model that computes revenues through participation in energy and A/S markets with five-minute granularity. Given simulated energy and ancillary services pricing information, ESOP solves for optimal dispatch decisions unique to a price-taking resource's technological characteristics and a regional market's participation rules.*[24]

CRA looked at historical relationships between day-ahead energy, real-time energy, and ancillary services prices to help shape the MISO price forecasts that were input into the ESOP model. NIPSCO and CRA evaluated battery storage, solar hybrid, and gas resources within the ESOP model to try to estimate the potential value streams that would be available for these resources in the sub-hourly energy and ancillary services markets. NIPSCO and CRA found that standalone battery storage resources provided the highest value out of all of the resources evaluated in the ESOP model.

These $/kW-year values[25] are given in NIPSCO's 2021 IRP. We took those values and applied them to each MW of battery storage, solar hybrid, gas peaker, and gas CC in the CAC Preferred Plan and the Duke Revised Preferred Plan. These values were then deducted from the portfolio PVRR. Table 9, below, shows the PVRR for the CAC Preferred Plan and the Duke Revised Preferred Plan with these adjustments for ancillary services included. The adjustment is larger for the CAC Preferred Plan since it includes a larger build out of battery storage resources, and the gap between the plans grows from 2.3% without the adjustment to 3.6% with the adjustment.

Table 9. PVRR Comparison with Flexibility Adjustment ($000)

Portfolio	EnCompass PVRR	FOM	CAPEX	Flexibility Adjustment	PVRR
CAC Preferred Plan	$18,819,020	$[redacted]	$[redacted]	$552,906	**$19,602,119**
Duke Revised Preferred Plan	$18,363,070	$[redacted]	$[redacted]	$305,872	**$20,336,686**

[24] NIPSCO 2021 IRP, page 240.

[25] NIPSCO's CAC Informal Request 1-021 Attachment A.

2.3 CO_2 Emissions

In addition to having a lower PVRR, the CAC Preferred Plan also has lower cumulative emissions between 2021 and 2041 compared to the Duke Revised Preferred Plan. Figure 6, below, shows the comparison of the cumulative CO_2 emissions between the CAC Preferred Plan and the Duke Revised Preferred Plan. The cumulative CO_2 emissions from the CAC Preferred Plan are about 16% lower than the cumulative CO_2 emissions from the Duke Revised Preferred Plan.

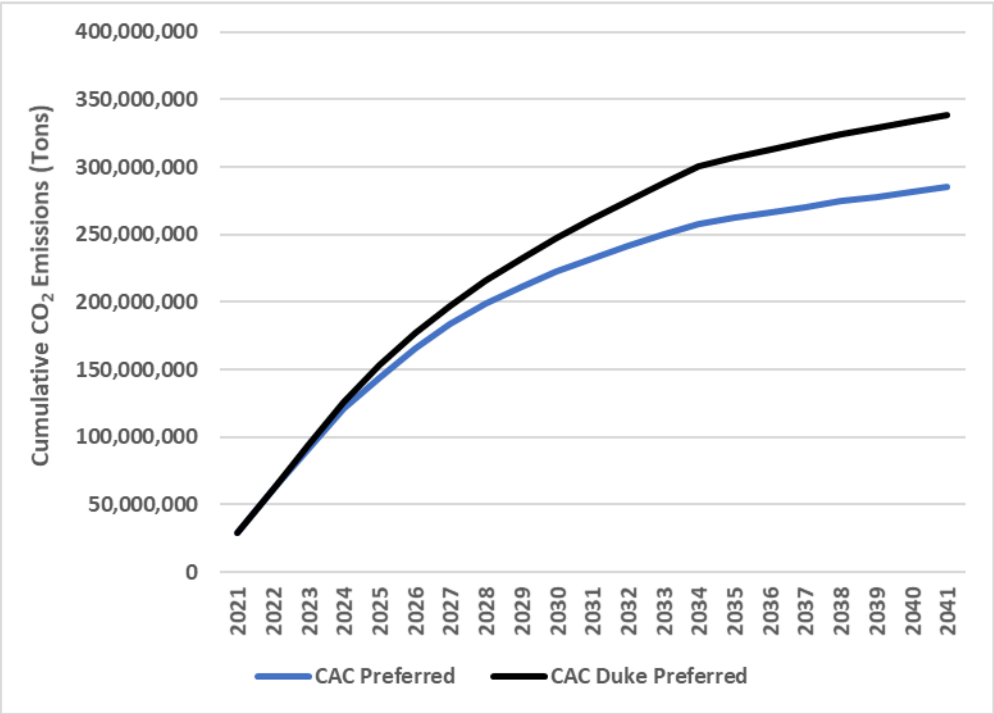


Figure 6. CO_2 Emission Comparison (Tons)

2.4 Scorecard

We did not attempt to compare the plans in terms of Duke's scorecard metrics. We have numerous concerns about several of Duke's metrics including the reliability, resilience, and environmental sustainability metrics as explained in our separate report on Duke's IRP.

2.5 Future Analysis

As we proceeded with this modeling, we were well aware that many factors have shifted dramatically since the development of the data to support this IRP. It was not possible for us to fully update Duke's database to account for changes in fuel prices, wholesale market prices, supply-side costs and delays, etc., so we chose to update none of these items (with the exception of the first years available and certain build constraints).

As Duke proceeds with using this IRP to support resource decisions, however, it will be imperative that it update its database to reflect the current realities of its electric system and the factors influencing it. We also request Duke to invite stakeholders to the table to work on this update together, well in advance of any resource filings, so that consensus can be pursued.

3 Summary of Findings

The EnCompass modeling described in this report demonstrates that a resource portfolio of additional renewable, battery storage, energy efficiency, and demand response resources can be lower in cost and have lower CO_2 emissions, when compared to Duke's portfolio that includes the new 1,211 MW CC added in 2027 and a later Edwardsport conversion date. ***As Duke moves forward with potential regulatory approvals for new capacity, we request Duke to invite stakeholders to the table to work on reaching consensus on modeling disagreements well in advance of any resource filings.***

PUBLIC ATTACHMENTS TO

A Cost-Effective, Cleaner Energy Portfolio for Duke Energy Indiana Customers

Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Informal Request 1
2021 Integrated Resource Plan

<u>CAC Informal Request 1-021:</u>
Please refer to Figure 9-42 on page 257 of the 2021 IRP. Please explain how the reliability metric "Reduction to 30-Year NPVV (Ref Case) $M" is calculated for each replacement portfolio and provide the workbooks with all formulas and links intact used to make that calculation.
<u>Objections:</u>
<u>Response:</u>
The "Reduction to 30-Year NPVRR (Ref Case) $M" metric was based on the results from the sub-hourly modeling performed in the ESOP model, as described in Section 9.2.6 of the IRP. Please refer to Section 9.2.6.6 of the 2021 IRP for the explanation of how the metric was calculated. As noted, the annual $/kW-yr incremental value from the ESOP analysis was attributed to each MW of storage, solar plus storage, or gas peaker capacity in all portfolios to arrive at an aggregate total net present value impact. This metric is intended to present the potential value that could be realized by flexible resources in the portfolios in the sub-hourly energy and ancillary services markets on an NPVRR basis. Please refer to the spreadsheet entitled "CAC Informal Request 1-021 Attachment A" for a documentation of the calculations performed to develop the scorecard metric. The "AS Value" tab contains the incremental $/kW-yr resource-specific values that were calculated from the ESOP model analysis in nominal $ across all four market scenarios. Note that these are the same values NIPSCO presented in Figure 9-33 of the IRP report, although the report figure is in real 2020$. These values are then applied to each new resource in the nine portfolios in the "AS Value owned resources Calcs" and "AS Value for PPAs Calcs" tabs. The "Summary" tab calculates the aggregate portfolio impact and summarizes the net present value of results. The summary across all scenarios matches Figure 9-34 from the 2021 IRP, with the Reference Case results (shown in Cells B3:B11) used for the scorecard metric.

CAC
Duke 2021 IRP
Data Request Set No. 3
Received: November 16, 2021

Confidential Attachment Referenced
CAC 3.1

Request:

Please provide the post process data for production cost runs.

Response:

See Confidential Attachment CAC 3.1-A.

Sierra Club
Duke 2021 IRP
Data Request Set No. 4
Received: September 24, 2021

Confidential Attachments Referenced
Sierra Club 4.1

Request:

Refer to Duke's response to Sierra Club request 2.1. Regarding the cost the Company modeled for new Gas Plants (Combined Cycle and Combustion Turbines):

a. Please provide the source for all capital cost and FOM cost assumptions Duke relied on in its modeling runs for Duke Indiana's footprint.
b. Please explain how the result from the Request for Information (RFI), Burns and McDonnell study data, and internal company data were used to develop the Company's gas plant cost assumptions.
c. Please provide the following:
    i. The results of the RFI
    ii. The Burns and McDonnell study
    iii. Any internal data, reports, or documentation on how much it cost Duke Indiana or any other Duke utility to build a new gas plant in the past 10 years.
d. Explain why the gas capital costs used in the MISO market runs differed from the costs Duke used for its own optimized runs.
e. Has Duke conducted any model runs with higher gas plant capital cost sensitivities to evaluate the optimal resource solution, assuming industry standard capital costs (such as NREL ATB)?

Objection:

Duke Energy Indiana objects to providing information not used by Duke Energy Indiana in the development of its 2021 Integrated Resource Plan as not reasonably calculated to lead to admissible evidence. Duke Energy Indiana further objects to subpart a. as vague and ambiguous and overly broad, particularly the use of the term "source." Duke Energy Indiana objects to subpart c(iii) of this request related to "any other Duke utility" as overly broad and not reasonably calculated to lead to admissible evidence.

Response:

Subject to and without waiving or limiting its objections and assuming the portion of the request seeking the "source" of the assumptions relied on in the modeling seeks information regarding the cost assumptions used in the Company's 2021 IRP modeling, Duke Energy Indiana responds as follows:

a. See objection. Duke Energy Indiana is providing Confidential Attachment SC 4.1-A, the Generic Unit Summary containing the cost and performance data for new technology options, and Confidential Attachment SC 4.1-B, the Fixed Charge Rate Model. These costs are inputs to Encompass for the Duke Energy Indiana level model runs.

b. The RFI data did not impact the development of the cost for the Company's gas plant assumptions. The gas plant assumptions were from Confidential Attachment SC 4.1-A. Internal company data was also not used but for certain financial assumptions explained in the response to subpart d. below.

c.
   i . The RFI data will be used as a sensitivity to assess the change in the selection of the resources in the portfolio optimized for the Reference w/ CO2 Regulation scenario. See Confidential Attachment SC 4.1-C.
   ii. Please see Confidential Attachment SC 4.1-A.
   iii. Duke Energy Indiana has not built a new gas plant in the last 10 years, so it has no cost information. As to other Duke utilities, see objection.

d. The costs used in both the MISO and Duke Energy Indiana level modeling are from Confidential Attachment 4.1-A. There are differing financial assumptions that are the source of the cost difference. Specifically, for the Duke Energy Indiana modeling runs, the Company used the technology-specific inflation rate and the LFCR from Confidential Attachment SC 4.1-B. In addition, Duke Energy Indiana uses the S.O. adders (also from Confidential Attachment SC 4.1-B) for solar and batteries. For the MISO level runs, the Company uses the Horizons Energy financial assumptions (which were previously provided in the modeling files for the MISO-level runs).

e. No.

CAC
IURC Cause No. 45654
Data Request Set No. 6
Received: February 10, 2022

CAC 6.1

Request:

Please refer to Figure V.1 on page 88 and 89 of the 2021 IRP.

a. Please explain the difference between "ST Capital Cost Inflation" and "LT Capital Cost Inflation".
b. Please explain if the hourly profile modeled in EnCompass for new solar resources assumes a 1.45 overpanel ratio for standalone solar and 1.65 for solar plus storage. If a different ratio is assumed for new solar and solar hybrid resources, please provide the ratio amount.

Response:

a. The ST Capital Cost Inflation is the expected cost rate of change of each technology over the first 10 years of the forecast. The LT Capital Cost Inflation is the expected cost rate of change of each technology from the end of the ST period through the end of the forecast (2036).

b. The Company assumed 1.4 overpanel ratio for both standalone solar and solar plus storage.

CAC
IURC Cause No. 45654
Data Request Set No. 6
Received: February 10, 2022

Confidential Attachments Referenced
CAC 6.18

Request:

Please provide the workbook, with all formulas and links intact, used to develop the levelized costs for new energy efficiency resources.

Response:

Please see Confidential Attachments CAC 6.18 A-F:

- Confidential Attachment CAC 6.18-A: Avoided T&D value of bundles
- Confidential Attachment CAC 6.18-B: Measure Summary & Levelized Costs - 2021-2023
- Confidential Attachment CAC 6.18-C: Measure Summary & Levelized Costs - 2024-2026
- Confidential Attachment CAC 6.18-D: Measure Summary & Levelized Costs - 2027-2034
- Confidential Attachment CAC 6.18-E: Measure Summary & Levelized Costs - 2035-2042
- Confidential Attachment CAC 6.18-F: Measure Summary & Levelized Costs - 2043-2050