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INDIANA UTILITY
REGULATORY COMMISSION

**SOUTHERN INDIANA GAS AND ELECTRIC COMPANY**
**d/b/a CENTERPOINT ENERGY INDIANA SOUTH**
**(CENTERPOINT INDIANA SOUTH)**

**IURC CAUSE NO.** 45564

**DIRECT TESTIMONY**
**OF**
**NELSON BACALAO**
**PRINCIPAL CONSULTANT, SIEMENS PTI**

**ON**

**INTEGRATED RESOURCE PLAN PROCESS AND RESULTS**

**SPONSORING PETITIONER'S EXHIBIT NO. 6**

**ATTACHMENT NB-1**

# DIRECT TESTIMONY OF NELSON BACALAO

## I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is Nelson Bacalao. My business address is 703 Detering St. Apt A Houston TX 77007.

**Q. By whom are you employed and in what capacity?**

A. I am a Principal Consultant at Siemens PTI ("Siemens PTI").

**Q. On whose behalf are you submitting this direct testimony?**

A. I am submitting testimony on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("Petitioner", "CenterPoint Indiana South", "CEI South", or" Company").

**Q. Have you previously testified before the Indiana Utility Regulatory Commission (the "Commission") or other public utility commission?**

A. Yes, I testified before the Puerto Rico Energy Bureau First and Second IRP, Cases No. CEPR-AP-2015-0002 and CEPR-AP-2018-0001, on behalf of the Puerto Rico Electric Power Authority ("PREPA").

**Q. What is the purpose of your testimony in this proceeding?**

A. The purpose of my testimony is to support CenterPoint Indiana South's 2019/2020 Integrated Resource Plan ("2019/2020 IRP") process, as well as Petitioner's Generation Transition Plan, and address issues related to the cost estimates and assumptions associated with the new Combustion Turbines additions proposed in the Preferred Portfolio from the 2019/2020 IRP.

**Q. Please summarize your education and experience relevant to your testimony in this case.**

A. My relevant education and experience are discussed within my resume, a copy of which is attached as Petitioner's Exhibit No. 6, Attachment NB-1. I hold a Ph. D. in Electrical

Engineering from the University of British Columbia, Vancouver, BC, Canada, earned in 1987. I hold a Master Engineering (Electrical) degree from Rensselaer Polytechnic Institute in Troy, NY, earned in 1980. I hold an Electrical Engineer degree from Universidad Simon Bolivar in Caracas, Venezuela, earned in 1979. I have been employed by Siemens PTI since January 2006. I am a Principal Consultant based in Houston and my professional experience covers technical and strategic consulting services to utilities, governments, regulators, independent project developers, and the financial community, in domestic as well as international assignments. My work has been centered on power system planning with emphasis on Integrated Resource Planning, integration of renewable generation and the impact on transmission and distribution systems.

**Q. Please summarize the history of Siemens PTI and your consulting relationship with CenterPoint Indiana South.**

A. Siemens PTI is the consulting unit of Siemens Industry and has been in the power system consulting business since 1969 under the name of Power Technologies Inc. PTI became part of Siemens in January 2006. Siemens PTI's continued growth led to the acquisition of Pace Global Energy Services, to strengthen our capabilities in market analytics and general Energy Business Advisory. Siemens PTI provided support for Petitioner's 2019/2020 IRP and continues to be engaged to provide testimony support. With Siemens PTI, I have provided consulting services to CenterPoint Energy Houston Electric[1] on the areas of interconnection studies and North American Electric Reliability Corporation ("NERC") Compliance (CIP-14).

**Q. Please summarize Siemens PTI's role in the 2019/2020 CenterPoint IRP process.**

A. Siemens PTI contributed to Petitioner's 2019/2020 IRP process in several key areas. The main contribution was the management and development of the IRP modeling (including some input development), strategic consulting, participation in the stakeholder process, and scorecard development.

[1] CenterPoint Energy Houston Electric is a subsidiary of the same parent company (CenterPoint Energy, Inc.) as CenterPoint Indiana South.

**Q. Please describe Siemens PTI's recent experience and expertise in structuring and leading integrated resource planning for utilities such as CenterPoint Indiana South.**

A. Siemens PTI is a leading consultant for integrated resource planning, with extensive experience in structuring and facilitating IRPs for utilities throughout the United Stated and Caribbean. The following list represents a selection of recent clients that have engaged Siemens PTI to contribute to their IRP processes: Orlando Utilities Commission (FL), Peninsula Clean Energy (CA), East Bay Community Energy (CA), San Jose Clean Energy (CA), Clean Power Alliance of Southern California (CA), Clean Power San Francisco (CA), Memphis Light Gas and Water (TN), and other utilities and load servicing entities with whom we are under confidentiality agreements in Missouri and other states. Siemens PTI also assisted Petitioner in its 2014 and 2016 IRP processes and is currently assisting another Indiana electric utility with its IRP, currently in the stakeholder process.

**Q. What have you done in preparation to develop opinions regarding the 2019/2020 IRP and CenterPoint Indiana South generation plan?**

A. I did not have a direct role in preparing the 2019/2020 IRP; hence, I am bringing my independent view of how the process was conducted. In order to conduct my review, I read the IRP reports, and reviewed the various stakeholders' filings and IRP workpapers.

## II. MODELING, GENERATION PLANNING, AND SCORECARD

**Q. Have you reviewed the documentation filed by CenterPoint Indiana South on the IRP and the corresponding workpapers and models?**

A. Yes, I have. The volume of information is quite substantial, and I have sought to became familiar with the rationale used by CEI South to identify the Preferred Portfolio with the support of my colleagues .

**Q. Are you aware that the Preferred Portfolio (High Technology) includes the installation of two gas turbines rated 236 MW each?**

A. Yes, I am aware of that recommendation of the Preferred Portfolio and reviewed the reasons behind the recommendation.

**Q. Describe your view on the approach used in the IRP for selecting the Preferred Portfolio's two gas turbines.**

A. In its Order in Cause No. 45052, the Commission explained that long-term risk is an important factor to be considered in the context of generation proposals: "Because unwinding assured cost recovery should an asset become uneconomic is not a commonly employed regulatory option, it is prudent to ensure during the pre-approval process that we understand and consider the risk that customers could sometime in the future be saddled with an uneconomic investment." Cause No. 45052 Order, p. 20. Petitioner's Witness Steven C. Greenley further addresses this concept in his testimony. I would describe this as the risk of buyer's remorse: the risk that a decision is made today which the Company and stakeholders later regret. Thus, the analysis should provide the decision makers information on the performance that these decisions have under future states of the world and identify which decisions are most likely to perform best and minimize the chances of buyer's remorse or regret.

The approach that Siemens PTI uses to analyze portfolios is to analyze in detail those portfolios that perform best across the relevant metrics and make a recommendation by identifying the portfolio that minimizes the risk. To achieve this, my approach is to review portfolio decisions and identify those that minimize the impact of having it wrong – the impact of an asset becoming "uneconomic" in the Commission's words. I sometimes call this identifying the risk and impact that a decision will later be regretted by the utility, and hence its customers and stakeholders. Based on my review of the analysis done by CEI South, I find it consistent with the approach above and I think the decision to build the two combustion turbines ("CTs") is consistent with the public convenience and necessity in part because it fulfills the Company's needs for capacity and peaking energy with generation resources that the Company and its stakeholders are unlikely to regret.

**Q. Can you please elaborate?**

A. We are entering a period of tremendous transition in the power generation industry. For decades, the industry has primarily relied upon fossil fuel for its generation resources, more specifically coal. In the recent past and over the coming years, much of that coal-fired generation will be retired as the industry transitions to portfolios consisting much more extensively of renewable resources. Our grid cannot switch entirely to renewable resources, however, because renewables must be supported by dispatchable power. This is not simply because of the intermittency of renewables but also is a function of the contribution that they provide to support the system peak and the required reserves. In the wintertime, with shorter days, there will not be sunlight during the evening peak and even for summer, as more photovoltaic generation is added to the system, net peak displaces to the evening, reducing the contribution of the renewable. So, the challenge becomes identifying the proper mix of renewable resources and dispatchable resources. Dispatchable resources will be more susceptible to regret if gas prices rise; renewable resources will be more susceptible to regret if capacity prices rise. A portfolio that mitigates the risk and impact of regret is a portfolio that navigates well through these often-competing risks. Let's take one risk factor at a time and assess how this decision plays out for the Preferred Portfolio with the CTs[2].

**Q. How do the portfolios compare when considering the risk of gas price volatility?**

A. The CTs' role in a portfolio is to provide peaking power and reserves. The peaking power functionally refers to the dispatch of generation during those peak load hours when there is insufficient base load generation or renewables in the system to supply the load. This typically occurs in relatively few hours per year. The reserve functionality refers to standing-by to supply the load in case a generation outage occurs. This all means that the CTs, as opposed to other base load generation (e.g., the Combined Cycle generators or Steam Turbine generation), run and burn gas only for a few hours during the year and hence are much less affected by gas price fluctuations. In the specific case of the Preferred Portfolio, the CTs have a very low capacity factor[3], an average of approximately 3% for the planning period for Reference Case conditions, which is much lower than those typical for base load generation (60% or higher). Another way of seeing this is considering that the cost of fuel for peakers typically represents about 2% of the net present value of the revenue requirements ("NPVRR"), thus the gas price may double and only have an effect of 2% increase in the NPVRR.

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[2] These are the other portfolios that had the lower net present value of the revenue requirement ("NPVRR") and performed well across a wide range of factors: Reference Case, Renewable + Flexible Gas, and Renewable 2030 (See Figure 8-8 of the 2019/2020 IRP Volume 1 pg. 251).
[3] Capacity Factor = Energy Produced / (Installed Capacity x hours of the year).

Another aspect to consider is that CTs can be turned on and off with great flexibility which makes them a good companion to intermittent renewables. In contrast, steam gas generation as would be the case of a converted A.B. Brown to gas is much less flexible and can be locked to run at minimum levels as it cannot be turned off and on as frequently. As a reference, the table below shows the NPVRR of the ABB1 + ABB 2 Gas Conversion scenario under reference condition and the present value of the fuel cost for the converted ABB1 and ABB2 and we see that represents 3.5% of the NPVRR. On the other hand, for the Preferred Portfolio (i.e., the High Technology Portfolio), the present value of the fuel costs represents 2%, 44% less. We also note in this table that with the exception of the Renewable 2030 Portfolio that stops using gas by 2030, the fuel cost of the Preferred Portfolio as a percentage of their NPVRR is the lowest among the least cost portfolios.

**Table 1**

| | NPVRR M$ | NPV NG Costs for Peaking Units M$ | NG Cost as % NPVRR |
|---|---|---|---|
| Bridge ABB1 + ABB2 | $2,887 | $101.92 | 3.5% |
| Preferred Portfolio – High Technology | $2,679 | $52.76 | 2.0% |
| Renewables 2030 | $2,678 | $37.78 | 1.4% |
| Reference Case | $2,616 | $65.47 | 2.5% |
| Renewables + Flexible Gas | $2,600 | $55.95 | 2.2% |

**Q. How does the risk of higher capacity prices affect the portfolios?**

A. As I explained previously, those portfolios that are more reliant on dispatchable power face a higher risk from gas price volatility; however, those portfolios more reliant on renewable resources will face a higher risk from capacity price volatility. CenterPoint Indiana South as a Midcontinent Independent System Operator ("MISO") member must meet the MISO Planning Reserve Margin Requirement ("PRMR"). In the IRP, a Planning Reserve Margin based on Unforced Capacity ("UCAP PRMR") requirement of 8.9% of the coincident peak load[4] was used, which is in line with MISO's requirements[5] and must be met by the capacity contributions of the resources in the portfolio or by market capacity purchases. Each of the resources owned or contracted by CenterPoint Indiana South

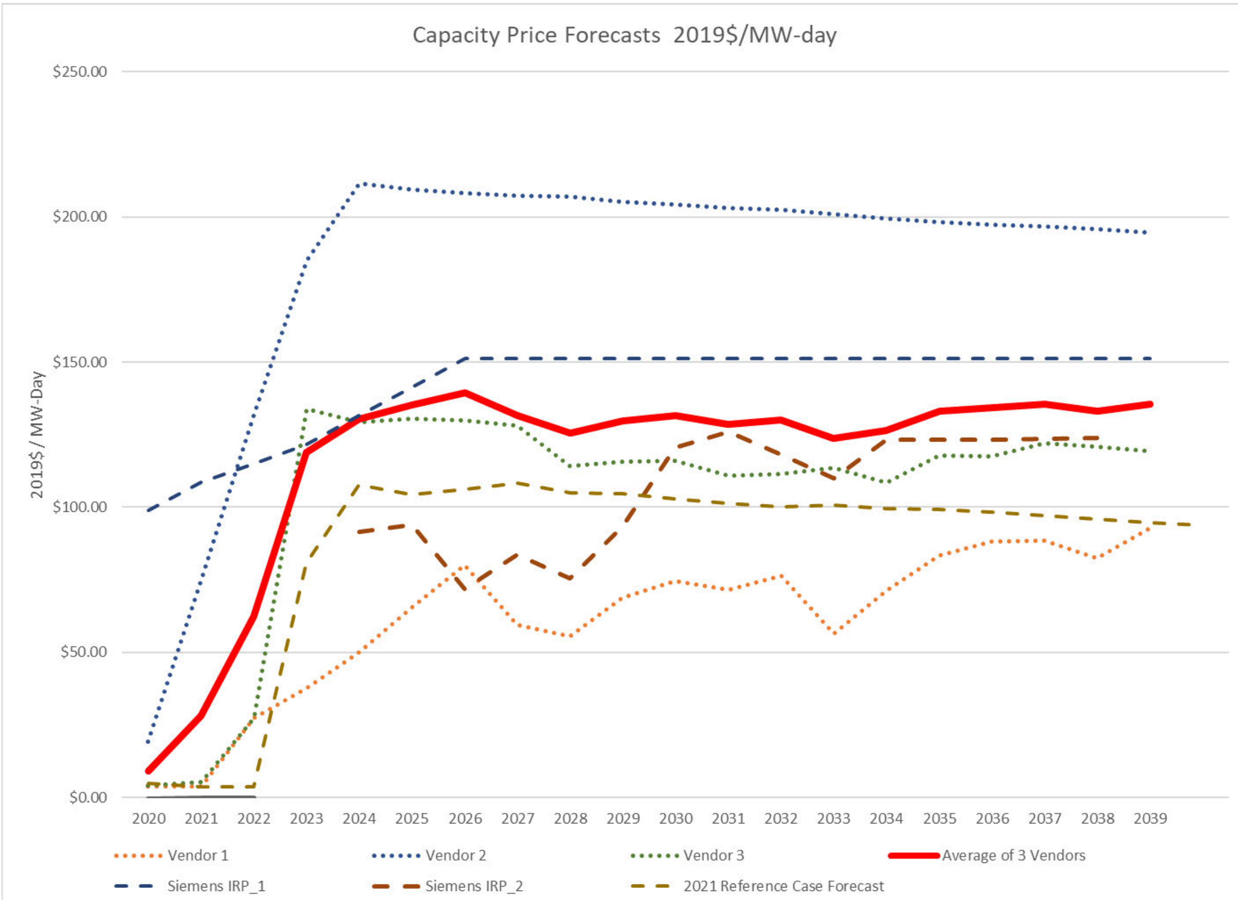
[4] This is CenterPoint Indiana South's load at the time of MISO's system wide peak.
[5] 2019/2020 IRP Volume 1, pg. 160 and MISO's Planning Year 2020-2021 Loss of Load Expectation Study Report.

contributes to meet the PRMR requirement and gas generators like the CTs contribute between 90% to 95% of its installed capacity to meet it[6]. Any shortfall must be procured in MISO's Capacity Auction, whose prices can be very volatile and difficult to predict as they depend on a tight balance between offer and supply. This can be observed by noting the widespread in the forecast as shown Figure 7-7 of the IRP Volume 1 and reproduced below, where we see that the high forecast is more than double the low forecast and gets close the MISO's ceiling equal to the cost of a new entry ("CONE") to provide the reserves ($257 MW/day).

Another aspect to consider is that in the below while the forecast for Vendor 1, which is PACE (a Siemens Company at the time), is the lowest, forecasts change as vendors have more information and consider the situations of the companies that will have to go to market to secure capacity (either spot or bilateral). In the figure I also added Siemens current Reference Capacity Forecast for MISO and the capacity forecast used for two IRPs in MISO that considered the particularities of the utilities. As noted, all updated forecasts are above those of Vendor 1 (PACE).

[6] Table 8-6 of CEI South IRP Volume 1, pg. 249.

**Figure 1**




Moreover, there are various risk factors that seem to indicate the potential for higher prices. The Local Resource Zone ("LRZ") 6, where CenterPoint Indiana South is located, does not have enough local resources to meet its Local Reliability Requirements ("LRR") and is dependent on imports from other MISO LRZs[7]. This makes Zone 6 dependent on the generation surplus in other zones, that may or may not materialize, adding practical deliverability risks and price risks. The capacity shortfall in MISO and specifically in Zone 6 is only expected to grow in the coming years, as noted in Petitioner's Witness F. Shane Bradford's testimony.

[7] Figure 5.9 of 2019/2020 IRP Volume 1 pg. 144 and Table 6-1 to 6-3 of MISO's Planning Year 2020-2021 Loss of Load Expectation Study Report.

The more heavily reliant a portfolio is on renewable resources, the greater the exposure to capacity price volatility risk. As more solar generation enters the market, the system resource adequacy determinations are likely to evolve from summer peaking to summer/winter peaking or a four seasonal construct as currently considered by MISO[8]. As I noted previously, there is a significant difference in the contribution of solar generation to meet the summer peak versus the winter peak. This is largely a function of the shorter days and the occurrence of the peak after dark. In the summer, much of the evening peak occurs while the sun is still shining; in winter, the evening peak occurs after dark. Additionally, as solar generation penetration increases, the summer peak contribution is also affected. As more renewable enter the system, the peak of the net load[9], which accounts for the reduction of renewable generation, displaces to later in the day when renewable resources also contribute less. This effect is captured in the industry with what is called the Effective Load Carrying Capability ("ELCC"), which is a measure of how much a resource can be depended on to supply the peak. For fossil fuel generation. this value is quite high — typically over 90% of the installed capacity; for solar it is currently 50% in MISO of the installed capacity for summer, and it reduces to only 5% for winter, as explained above. Both values for solar will reduce further as penetration increases. For wind generation, the ELCC is more uniform during the year and in the order of 15% for summer, spring, and fall, and 20% for winter.

As can be appreciated, as more and more fossil fuel generation retires and is replaced with renewables, the need for dispatchable power becomes more pronounced. A construct requiring meeting a winter PRMR requirement would have very low contribution of solar and would have to be met with thermal resources, wind resources, and storage[10]. As we have more and more solar penetration into the overall grid portfolio, this will drive up the cost of capacity in the market. The more reliant a portfolio is on renewables, the more it will rely on capacity purchases. If capacity prices rise more than forecasted, it increases the risk that a particular decision will be regretted.

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[8] RAN Reliability Requirements and Sub-annual Construct (misoenergy.org): https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf.

[9] The net load is the effective load of the system accounting for the effects of the renewable generation output.

[10] See Figure 8-6 and 8-7 of the 2019/2020 IRP Volume 1 pg. 249 for ELCC of thermal, wind and solar and its projections.

The Preferred Portfolio with the two CTs is much less susceptive to the impact on changes in capacity prices as it has the lowest forecasted amount of capacity purchases of the four least cost portfolios[11] and hence it has the lowest exposure to this risk. The table below shows for the four least cost portfolios and for the case where A.B. Brown is converted to gas, the average market capacity purchases, the present value of the associated cost and how much it represents as a percentage of the Net Present Value for the portfolio revenue requirements ("NPVRR"). We observe that the Renewable 2030 has the greatest exposure followed by the Reference Case and Renewable + Flexible Gas, A.B. Brown Conversion (Bridge ABB1 +ABB2) and the preferred portfolio (High Technology) has the least exposure.

**Table 2**

| Scenario | Average Capacity Purchases (2020-2039) MW | NPV of Cost M$ | % NPVRR |
|---|---|---|---|
| Bridge ABB1 + ABB2 | 207 | 50.97 | 1.8% |
| Renewables 2030 | 152 | 62.05 | 2.3% |
| Reference Case | 124 | 46.12 | 1.8% |
| Renewables + Flexible Gas | 121 | 45.43 | 1.7% |
| Preferred Portfolio- High Technology | 33 | 2.97 | 0.1% |

Another aspect to consider is that the ELCC of storage declines as penetration increases[12] and the Preferred Portfolio would be only marginally affected by a reduction of ELCC of storage as it only has 50 MW installed in 2039, which is not the case for the Renewable

[11] Renewable + Flexible Gas
[12] Storage was conservatively modeled in the IRP with a constant ELCC of 95%, however this value is likely to decline as more storage is added to system. For example, on a recent study for NY we are using 75% for a 4 hours battery as recommended by NYSO for penetrations greater than 1000 MW (see Expanding Cap. Eligibility: https://www.nyiso.com/documents/20142/5375692/Expanding%20Capacity%20Eligibility%20030719.pdf/19c4ea0d-4827-2e7e-3c32-cf7e36e6e34a) and in an study for CAISO a value as low as 54% was identified for high levels of storage penetration (see Energy Storage Capacity Value on the CAISO System: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/2019-20%20IRP%20Astrape%20Battery%20ELCC%20Analysis.pdf).

2030 that has 360 MW of storage by 2031. Simply put, as the level of storage increases in the MISO Market, the level of accredited capacity would go down. It is the same phenomenon discussed regarding solar resources. This risk was not considered within the IRP but is an important factor to consider when evaluating a portfolio that relies heavily on storage.

**Q. What conclusions do you derive from the above?**

A. I conclude that the Preferred Portfolio with two CTs has very low exposure to the risk of high fuel prices while providing almost full protection to the risk of high capacity prices. The Preferred Portfolio has nearly the least exposure when considering gas price risk, with only Renewables 2030 being less exposed. On the capacity side, the Preferred Portfolio has the lowest risk of exposure and by a large margin. Notably, the Renewables 2030 is most exposed on the capacity side. The Preferred Portfolio navigates these two competing variables very well and better than the other portfolios. In other words, compared to other portfolios, the effects of being wrong and regretting the decision are less pronounced.

**Q. How does the possibility of battery storage affect the analysis?**

A. Storage is a useful tool that can help address solar's inherent incapability to meet the system peaks and shift energy to those times when the sun is not shining. To address whether battery storage would have been a more economical solution than constructing two CTs, CenterPoint Indiana South conducted a sensitivity analysis where the CTs were replaced by storage that would provide similar amounts of reserve as the CTs. The storage was selected from a bid received on the All source RFP[13] and consisted of eight modules with 76.2 MW of three-hour storage each, totaling 609.6 MW. With expected ELCC of 71%, the resulting capacity value of 434.3 MW is slightly higher than the capacity value of the two CTs (409 MW).

**Q. Have you reviewed that sensitivity analysis?**

A. Yes. I reviewed the sensitivity calculations and identified that the building storage resulted in an increase of 5% on the NPVRR of the portfolio. This was driven by the higher capital and fixed O&M costs of the storage that are approximately 54% higher than corresponding

[13] See Section 6.1.1 of the 2019/2020 IRP Volume 1 pg. 149.

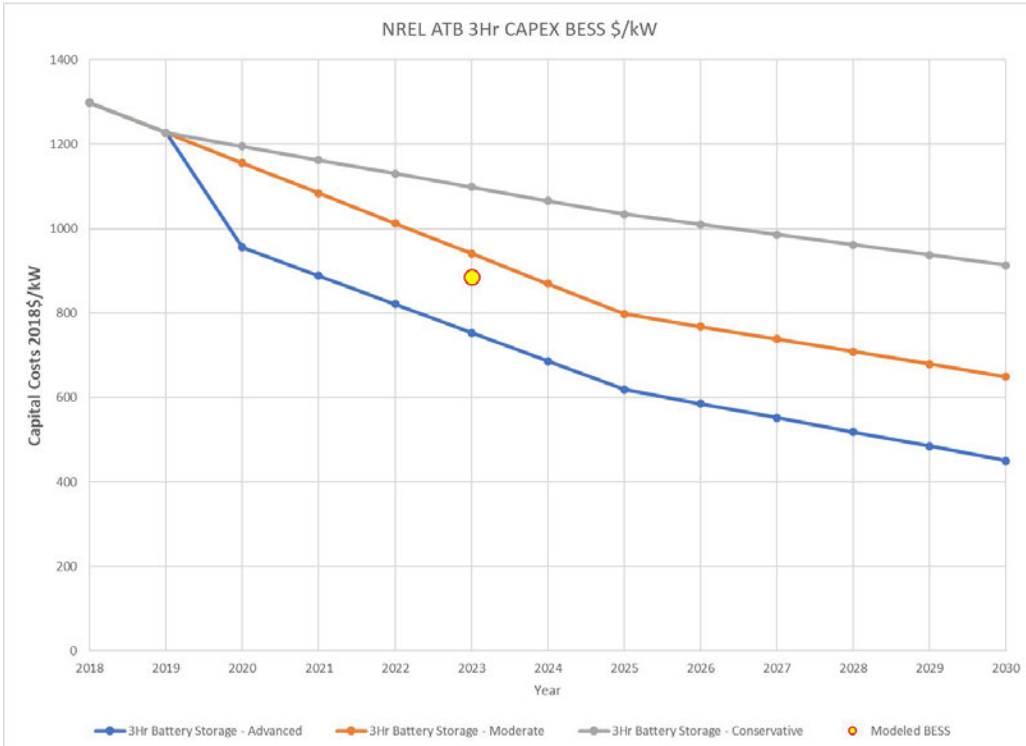
costs of the CTs and result in an 17% increase in the overall capital and fixed O&M costs component of the NPVRR. This increase in cost is partly compensated by a reduction in fuel costs (5% reduction) and emissions cost (2% reduction).

**Q. Are the prices for storage assumed in CenterPoint Indiana South's sensitivity analysis reasonable?**

A. Yes. First, these are actual prices that were submitted in response to an actual RFP. But given the importance of the Storage PPA costs in driving the results above, I further compared this cost with the 2020 NREL's ATB forecast[14]. To get a comparable capital cost in $/kW, I subtracted from the PPA yearly payments the expected component for Fixed O&M costs (using the ATB forecast) and then determined the implied capital using the same discount rate used in the IRP with a 15 year life. I further considered that CenterPoint Indiana South would have to enter this contract approximately two years ahead of the in-service date of the project (i.e., 2023). The figure below shows the result of the analysis where we note that the cost is below the expected trend (Moderate) and somewhat higher than the minimum expected costs (Advanced), thus confirming the adequacy of the values used in Petitioner's 2019/2020 IRP. In short, I agree with the conclusion that additional storage will be more costly than the two CTs and attempting to replace one or both CTs with storage would be an uneconomic decision.

[14] https://atb.nrel.gov/electricity/2020/data.php.

**Figure 2**




**Q. Are there other issues that should be considered besides economics when evaluating storage as a potential alternative?**

A. Yes. As discussed earlier, the ELCC of storage may not be constant over time and as the penetration increases, it could decrease and possibly significantly as identified in the California Independent System Operator (CALISO) study and in the New York Independent System Operator (NYISO) studies (see footnote 12 *supra*). Moreover, the storage considered was three hours duration and any real-life requirement with longer duration requirements could not be met. This is not the case with the CTs that can be in service for extended periods of time.

In summary, I think that the selection of battery energy storage in lieu of the CTs is not a robust solution and there is greater risk that it will result in higher costs and reduced services to CEI South's customers.

I think this summarizes well why I am of the opinion that CenterPoint Indiana South's decision to build the two CTs is a prudent decision for CenterPoint Indiana South and its customers and is in the public interest.

**Q. Can you describe the Balanced Scorecard Methodology used in CenterPoint Indiana South's IRP?**

A. The Balanced Scorecard is a method to present the results of an otherwise complex analysis effectively and concisely. Across the top are the key objectives to be assessed and this includes affordability typically measured by the NPVRR; environmental factors for example $CO_2$ emissions minimization; and risk factors such as risk of the NPVRR being higher than expected, or overreliance on an energy and capacity market that can be volatile. There can be other factors in the Balanced Scorecard, and I understand that the factors used by CenterPoint Indiana South were vetted via an extensive stakeholder process.

In the scorecard, each line contains the results for different portfolios allowing comparison.

The scorecard can be based on deterministic results, but in most advanced procedures the results of the Monte Carlo stochastic simulations are used. This was the case in CenterPoint Indiana South's IRP, which allowed, for example, to show the cost uncertainty by looking at the 95$^{th}$ percentile (i.e., the cost or value that would be exceeded only 5% of the time) across 200 iterations[15].

I have used the Balanced Scorecard in multiple assessments and in my opinion, it is a powerful tool to visualize the performance of multiple portfolios at a glance. The scorecard typically uses shades of the color green to depict favorable outcome and by inspection it is relatively easy to identify the best performing portfolios, allowing the identification of what is sometimes called the decision set, i.e., those portfolios that behave best in comparison with the rest and are likely to contain the preferred portfolio and should be

[15] The 95$^{th}$ percentile is the value that is exceeded only 5% of the time and the greater the difference of this value to the mean is indication of the sensitivity of the portfolio to one or more uncertainties. CenterPoint Indiana South considered the following variable uncertain (stochastics); Load (energy and peak), natural gas (high uncertainty variable), coal, $CO_2$ emissions costs, capital costs for solar, wind, BESS, CCGTs and CTs.

studied closely[16]. In the case of CenterPoint Indiana South's IRP, the Reference Case, the Renewable + Flexible Gas, the Renewable 2030 and the High Technology are clearly members of this decision set[17].

**Q. Is the Monte Carlo 95th percentile approach the only way that cost risk can be analyzed?**

A. No, there are other ways and I also looked at them to conclude that CenterPoint Indiana South's proposal to build the two CTs is prudent.

First, I look at how the different Portfolios NPVRR changes when subjected to different "states of the world" as described in the Scenarios that CenterPoint Indiana South considered[18]. For each of those scenarios, there is always a Portfolio that performs best (i.e., has the lowest NPVRR and performed well across other metrics) and would be the preferred decision if we had perfect foresight; this is sometimes called the No-Regret Portfolio for the given state of the world. Then I compare the other Portfolios under this state of the world (or future) and assess the difference with respect of the No Regret Portfolio and the difference is the degree of "Regret". With this approach we can factor the degree that different Portfolios benefit from a favorable outcome (e.g., a portfolio that could benefit more from a reduction in capital costs of renewable and storage than others)[19] and by how much they are shielded from adverse outcomes.

Using the results reported in in the IRP, I determined the Regret as defined above and calculated the simple average of the regret across the scenarios considered. Below I show the results of this assessment. This is a simple average of the deltas from the lowest NPVRR under the five different scenarios evaluated in the IRP. In other words, this analysis is focused purely on NPVRR, and each of the various scenarios are equally rated.

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[16] See for example the MLGW IRP (http://www.mlgw.com/images/content/files/pdf/MLGW-IRP-Final-Report_Siemens-PTI_R108-20.pdf) Exhibit 10 and subsequent analysis of Portfolios 5, 9 and 10 together with the TVA option that were included in the decision set.
[17] Figure 8-8 of Volume I of the 2019/2020 IRP.
[18] See Figure 2.5 of the 2019/2020 IRP pg. 94.
[19] The convenience of assessing the upside of Portfolios was also expressed in the Director's report where it indicates that "[CenterPoint Indiana South] uses the 95th percentile as the metric for cost uncertainty. This is reasonable but it ignores the uncertainty around the potential for lower-than-expected cost. It is possible that a portfolio has more downside cost benefit than other portfolios, but this was not considered by [CenterPoint Indiana South]."

For example, it assumes the risk of the "Low Regulation" scenario is the same as the risk of the "High Regulation." We see below that Renewable + Flexible Gas has the lowest average regret, i.e., the chances of regretting the decision under an adverse future are lower. This Portfolio is followed by the Reference and then the Renewable 2030 and High Tech (Preferred Portfolio) that are very close.

**Table 3**

**Regret assessment $000**

| Portfolio | Base Case | 80% CO2 Reduction by 2050 | High Technology | High Regulation | Low Regulation | Avg of Regret | Rank |
|---|---|---|---|---|---|---|---|
| P08 Renew ables + Peak Gas | $ - | $ - | $ - | $ 123,706 | $ 54,284 | $ 35,598 | 1 |
| Reference | $ 13,616 | $ 26,834 | $ 29,121 | $ 191,970 | $ - | $ 52,308 | 2 |
| P09 Renew ables 2030 | $ 78,052 | $ 55,902 | $ 180,539 | $ - | $ 239,400 | $ 110,779 | 3 |
| P10 - High Tech Portfolio | $ 85,673 | $ 76,146 | $ 64,432 | $ 272,291 | $ 69,030 | $ 113,515 | 4 |
| P04 Bridge ABB1 | $ 126,615 | $ 119,854 | $ 148,333 | $ 264,141 | $ 121,692 | $ 156,127 | 5 |
| P06 Diverse Small CCGT | $ 162,751 | $ 108,325 | $ 140,662 | $ 290,895 | $ 140,938 | $ 168,714 | 6 |
| P02 - Bridge BAU- 2029 | $ 234,682 | $ 177,416 | $ 254,987 | $ 367,092 | $ 25,078 | $ 211,851 | 7 |
| P03 Bridge ABB1 CCGT | $ 354,435 | $ 291,880 | $ 335,363 | $ 463,461 | $ 338,444 | $ 356,717 | 9 |
| P05 BridgeABB1 & ABB2 | $ 287,200 | $ 260,647 | $ 298,705 | $ 393,455 | $ 268,644 | $ 301,730 | 8 |
| P01 BAU | $ 540,376 | $ 430,441 | $ 579,651 | $ 653,076 | $ 32,426 | $ 447,194 | 10 |

**Q. This analysis would seem to suggest the Renewable + Flexible Gas would have the least adverse impact if the decision were later regretted under this simple analysis. Is that the correct reading?**

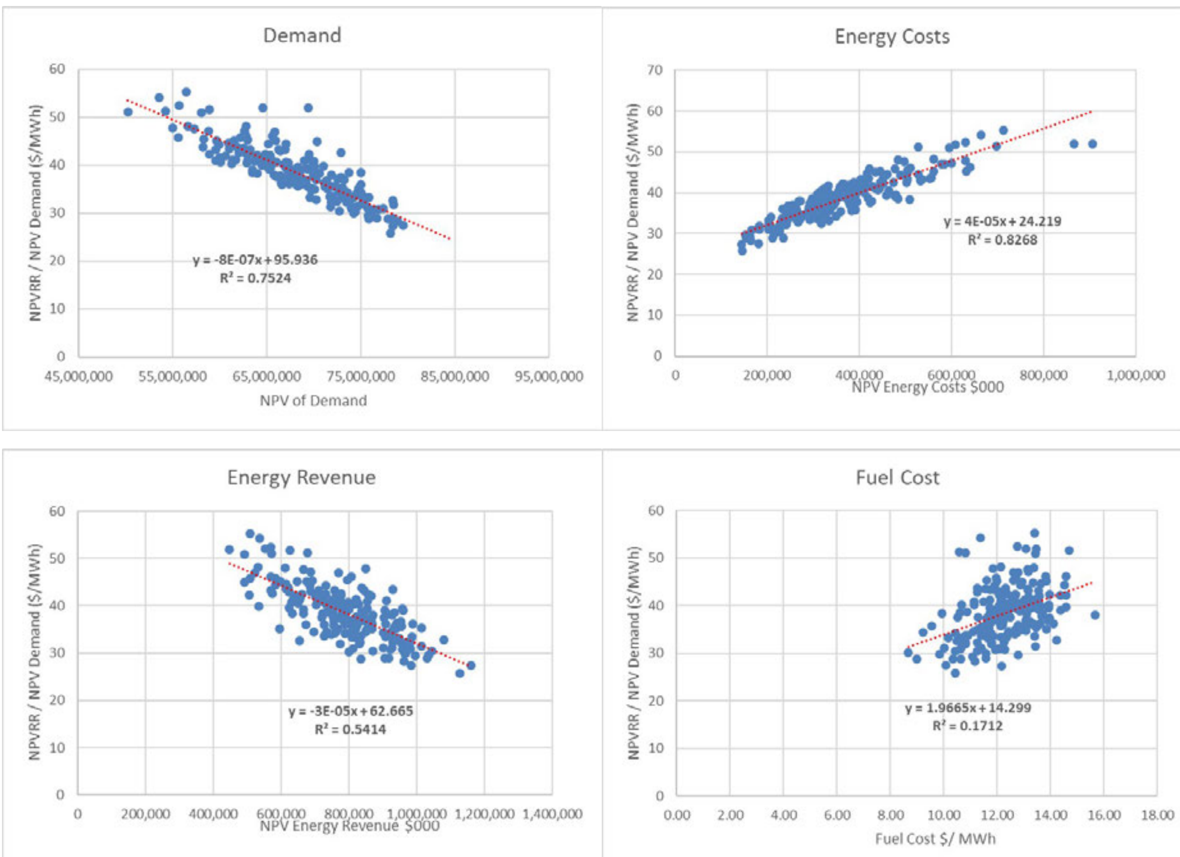
A. Yes, but with a qualification. Looking into this I noted that except for the Renewable 2030, all the Portfolios had a 236 MW CT built in 2024 and the Renewable + Flexible Gas had another built in 2033 versus the Preferred Portfolio that had it built together with the first unit. Thus, the option to delay the construction of the second turbine to 2033 in accordance with the Renewable + Flexible Gas should be considered. I investigated this and realized that first there are important construction efficiencies in building the two CTs together. As shown in Attachment 1.2 of Appendix 2 of the 2019/2020 IRP Volume 2, the cost of building the first unit (F Class Frame CT) is estimated to be in 2019$, $173 million and the cost of the second unit would be $121 million if they are developed at the same time, thus the construction efficiencies translate into $52 million savings. When I reviewed how the second unit was modeled, I noted that in both Portfolios, the fixed costs that include the capital recovery (amortization) were about the same, in fact the fixed cost for the second unit in the Renewable + Flexible Gas Portfolio was 98% of the cost for the same unit in the Preferred Portfolio. However, if the second unit were to be built later, these construction efficiencies would not be realized and the difference between the portfolios would be smaller. This benefit from construction efficiencies is not reflected in the table above. This difference alone, if included in the above analysis, would reduce the differences between the Preferred Portfolio and the Renewable + Flexible Gas to about 1.5%. Another aspect that would reduce the difference between the Portfolios is that Renewable + Flexible Gas Portfolio supplies a smaller load as it has 1% Energy Efficiency 2024 – 2026 compared with the High Technology (0.75%) and that it includes the retirement of F.B. Culley 3 in 2033 – 2034. If these additional factors were included in the High Technology case, the difference would be smaller and in the order of 1%.

Building simultaneously the two turbines also minimizes the market capacity risks that as I elaborated earlier are substantial. It minimizes disturbance on the system as there would major work being carried out at A.B. Brown once, and it preserves the interconnection rights that CenterPoint Indiana South has at A.B. Brown. As I noted previously, the simple averaging I have presented assumes the risk of all different scenarios is equal. I will demonstrate some of these differences later in my testimony.

**Q. Are there other approaches to evaluating the impact of the risk of choosing the wrong portfolio?**

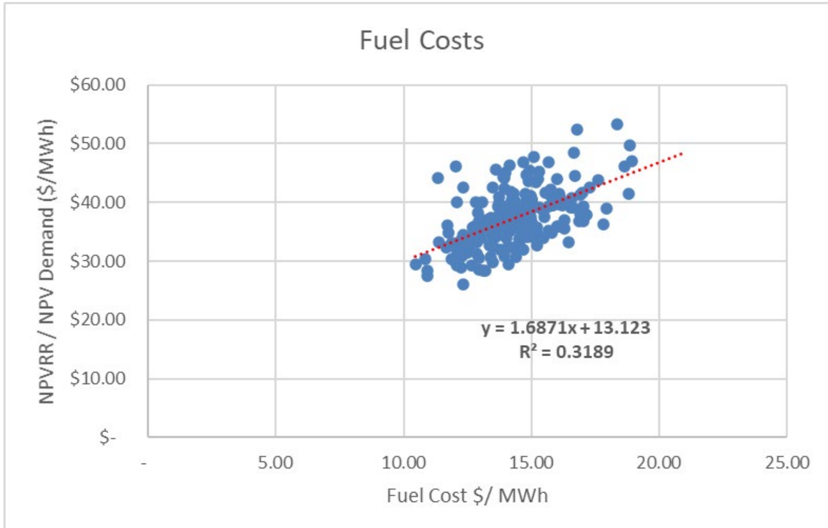
A. Yes. Another approach that I find useful is to identify the variables that most affect a Portfolio by reviewing the results of the Monte Carlo analysis. In this case, I look at how the average cost of the Portfolio under analysis changes as a function of uncertain variables. The Average Cost is determined by dividing the NPVRR by the NPV of the energy demand. I did this for the Preferred Portfolio and found that there is a clear correlation with the demand; higher demand to allocate the same fixed costs results in lower average costs per MWh, see first graph below that has on the X-axis the NPV of the Demand and the Y-axis the Average Cost. Also, there is a clear correlation with the Energy Cost (second graph) and with the Market Sales (third graph), as the first drives up the average cost up and second being an income rather than a cost. drives the average cost down. However, we note that changes in the fuel costs ($/MWh of NPV of Demand) are only weakly associated with changes in the Average Cost as can be noted in the fourth graph where we see a "blob" rather than a trend and we note the low $R^2$ (0.17) hence changes in fuel cost is not a significant risk for this Portfolio. I touched on this issue previously, when I evaluated the percentage of the NPVRR that was represented by fuel costs. But this analysis shows that the relatively limited risk of gas price volatility is fairly static: it correlates weakly with the portfolio costs.

**Figure 3**




To further illustrate this, I did the same exercise for the Portfolio where case where there is a small CCGT (433 MW) by 2026. This portfolio was expected to be still weakly correlated with the fuel prices but to a greater degree than the preferred portfolio as it has more fuel assets and this is shown in the figure below where we note an $R^2$ of 0.32, almost double that of the Preferred Scenario. So, for this gas conversion option, the risk of gas price is more closely correlated to the portfolio's average costs than the Preferred Portfolio and hence gas volatility has much greater impact.

**Figure 4**




**Q. Are there other aspects that you would like to highlight about the decision to build the two CTs?**

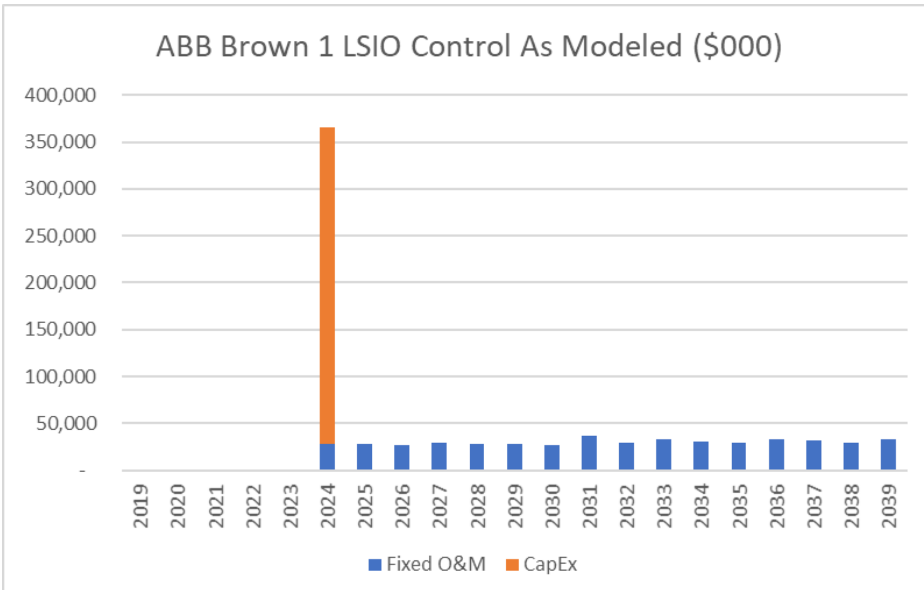
A. Yes, I find that the decision to build the two CTs adds flexibility to CenterPoint Indiana South's generation assets to deal with uncertainties that can affect demand growth or the future development of the CenterPoint Indiana South's and MISO's generation portfolio.

The CTs provide diversity in generation technologies and have option to be converted in the future.

**Q. Let's focus for a moment on the analysis of continued operations of A.B. Brown with upgraded emissions controls in the IRP. Is it a fair criticism to claim that the analysis was biased against the continued operation as the analysis considering the capital cost concentrated in 2025 rather than amortized over the life of the asset?**

A. No, I don't think it makes a difference at all and it was really the preference of the modeler. There is a time value of money and this works both ways in discounting for NPV calculations and for annualization of investments so it can be recovered over the life of the asset. We do this using the Capital Cost Recovery factor ("CCR") that multiplied by the capital investment of an asset converts it into a uniform stream of payments throughout the life of the asset. This was done for the capital investment of solar, wind and new generation offered to the model as candidates for selection. However, in the case of the A.B. Brown upgrades the modeler had the actual expected cashflow and modeled as such. This is shown in the figure below. The NPV of this cashflow stream is (2019) $401.2 million at a discount rate of 7.71% equal to the CEI South's weighted average cost of capital used in the IRP[20].

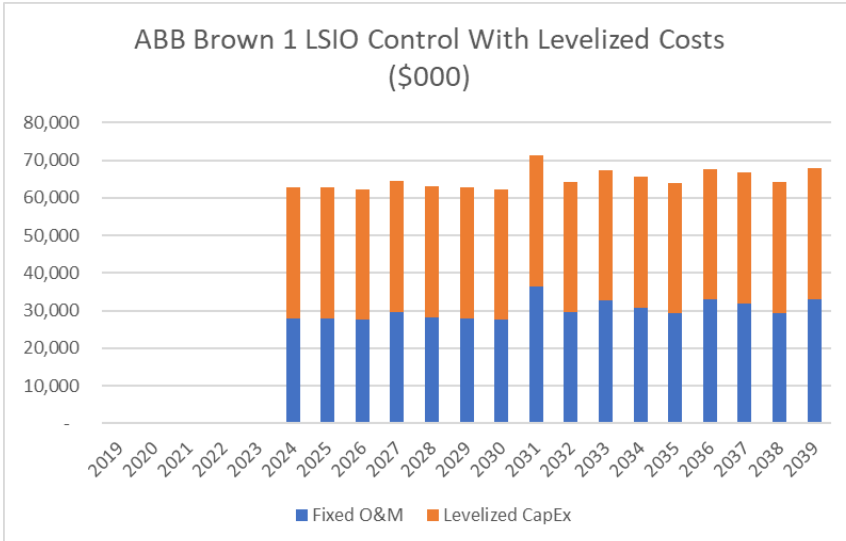
**Figure 5**




The analyst could have annualized the CapEx component above using the same discount rate above and 16 years amortization (the units would retire by the end of 2039) and produce a cashflow like the one below which has exactly the same NPV (2019) $401.2 million. Thus, there was no bias against the continuation of A.B. Brown, just the economics.

[20] See pg. 257 of Volume I of the CEI South 2019/2020 IRP.

**Figure 6**




**Q Should CenterPoint Indiana South have amortized the new CTs proposed in the Preferred Portfolio over a much shorter life?**

A. No, I don't think so. Even if in the future Indiana or the EPA were to adopt a net-zero policy as for example New York's CLCPA that requires the state's generation to be zero emissions by 2040[21], there is still a role for peaking generation like the CTs, which could be burning renewable natural gas ("RNG"), Green-Hydrogen or another net-zero emissions fuel. I was part of the team that conducted a study for the NY Research and Development Authority ("NYSERDA") to assess how the grid would evolve leading to a 100% emissions grid by 2040[22]. In the study we found that the optimal expansion plan was a mix of storage and thermal generation that by 2040 would use RNG at a cost of $23/MMBTU and subject to an availability limit of 32TBTU/year. We found that in the optimal plan there would be approximately 17,200 MW of thermal generation in the system, including some of the existing generation that did no retire and new CTs and combined cycle plants added as part of the expansion plan[23].

[21] The New York Climate Leadership and Community Protection Act sets a goal of having a 100% emissions free electricity by 2040 (CLCPA) (see https://climate.ny.gov/-/media/CLCPA/Files/CLCPA-Fact-Sheet.pdf).

[22] See Appendix E: Zero Emissions Electric Gris in New York by 2040 https://brattlefiles.blob.core.windows.net/files/20842_initial_report_on_the_new_york_power_grid_study.pdf.

[23] See Table 4-1 of Appendix E referenced in the prior footnote.

For this reason, I don't think it is necessary or prudent to reduce the life of the assets as proposed.

**Q As stated in "Response of CAC, Earthjustice, and Vote Solar to the Director's Draft Report for Vectren's 2019/2020 Integrated Resource Plan", do you agree that CenterPoint Indiana South's resource adequacy approach is inconsistent with the outcomes of MISO's policy change on the topic?**

A. No, I don't think the changes in MISO policy will have a significant impact on the plans. Upon my review of the models, I appreciated that CenterPoint Indiana South made sure that the portfolios would likely meet both summer and winter requirements, and any seasonal requirement for that matter. Yes, as noted in CAC, et. al. response, CenterPoint Indiana South used the same PRMR of 8.8% of the MISO coincident peak across all months, however I don't expect that this approximation will result in the plans being inadequate as I illustrate below.

First, Aurora's optimization ensured that there were enough resources to meet the most stringent yearly condition, which as expected happened in August of each year. This is shown in the figures below for 2030 for the Renewable+ Peak Gas, Renewable 2030 and High Technology portfolio, where the peak demand and reserve requirements are compared with the available capacity from resources across the year. In these figures the red line is the CEI South's coincident demand, and the dashed line includes on top of that the minimum reserve (8.9%) that Aurora maintained over this demand. This is compared with the capacity contribution, i.e., the ELCC I mentioned earlier, of all the resources in the portfolio including market capacity purchases that add up to a blue line "Total Resources" in the graphs.

As can be observed in the graphs even though the ELCC of renewable dropped in late fall, winter, and early spring (see the reduction in the top green area representing the renewable and effect in Total Resources - blue line), this drop in Total Resources is more than compensated in by the concurrent drop in demand resulting in greater margins between the requirement (dotted line) and the availability (blue line). This is particularly clear for the Renewable + Flexible Gas and Renewable 2030, where we see that in August the dotted line and the blue line coincide, and "Capacity Market Purchases" were required

(red band) that in an "Annual" construct needs to be maintained throughout the year. A similar situation is observed for the Renewable 2030, where again we see that during August the available total resources (blue line) meet the requirements (dotted line) and capacity purchases are required. We also note that in winter the margin of the resources over the requirement is small. Finally, we see that for the High Technology case the available resources were always above this year requirements and no market capacity purchases were necessary.

**Figure 7**

**Renewable + Flexible Gas Portfolio Demand, Reserves and Resources (MW).**

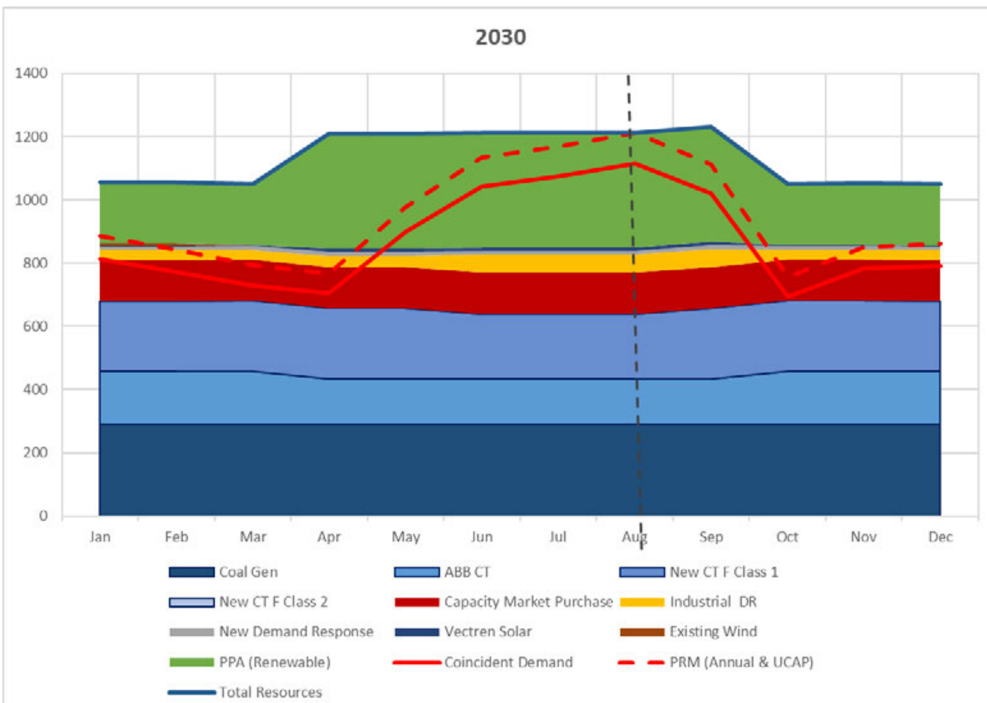


**Figure 8**

**Renewable 2030 Demand, Reserves and Resources (MW).**

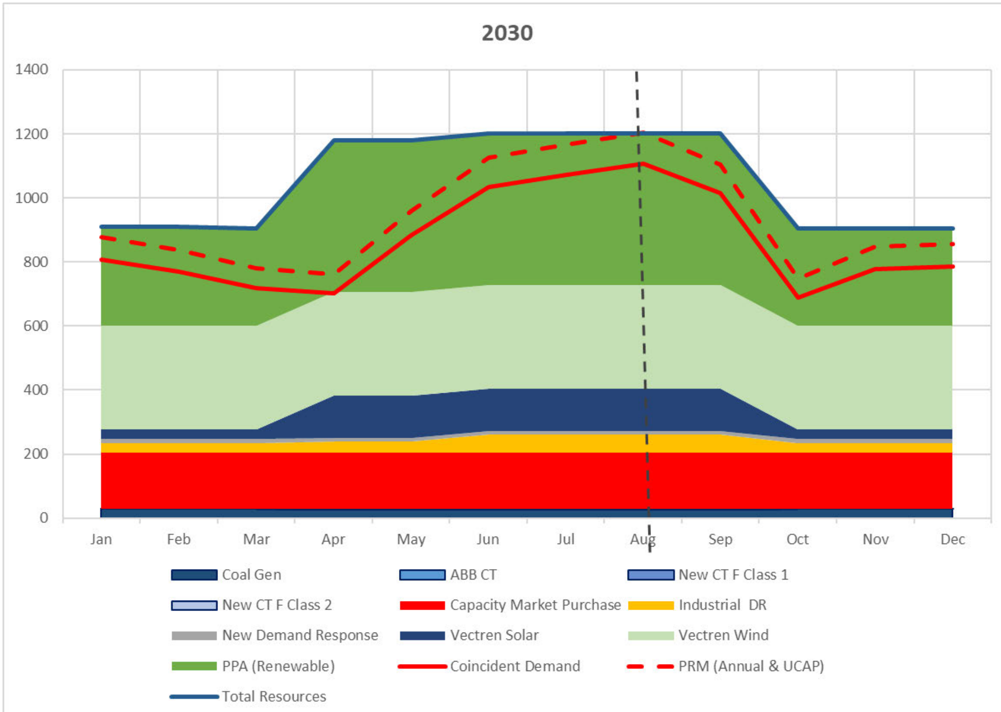
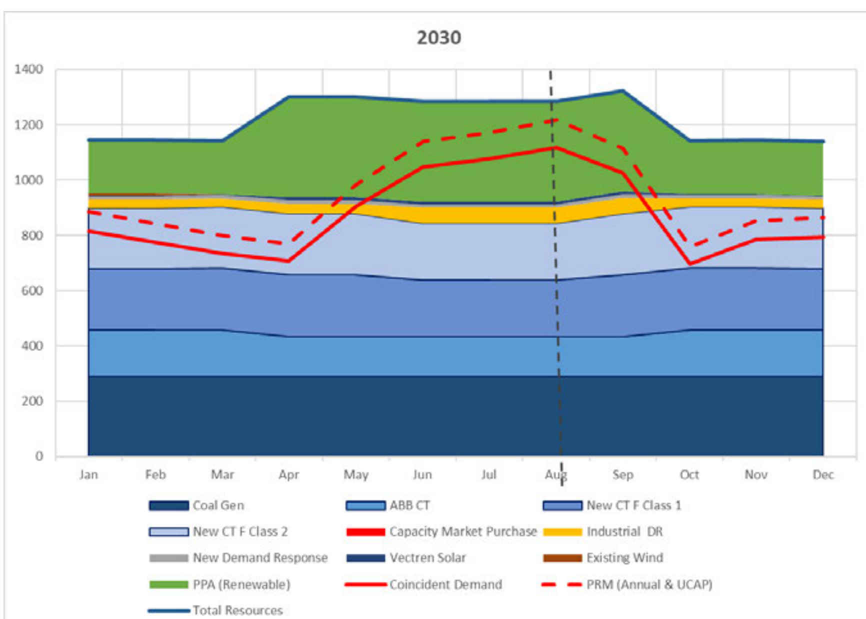



**Figure 9**

**High Technology Portfolio Demand, Reserves and Resources (MW).**



In summary, the August requirement defined the capacity needs of the portfolio and to meet it market capacity purchases are required on the Renewable + Peak and Renewables 2030 portfolio.

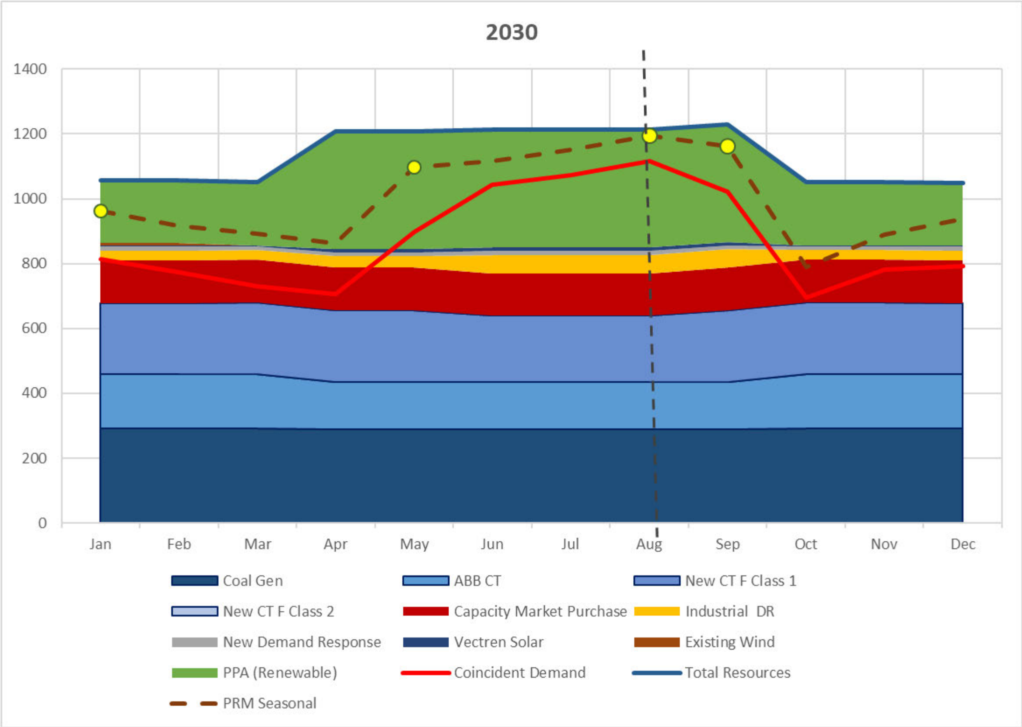
**Q. Please continue with your response to the comment of CAC/Earthjustice and Vote Solar, do you think a MISO Seasonal Construct would have a major impact?**

A. MISO has not yet defined what will be the final seasonal PRMR, however it is possible to illustrate how this may affect the Portfolios using the information shared by MISO on the "RAN Reliability Requirements and Sub-annual Construct"[24]. In MISO's document on page 23, the LRZ 6's Local Reliability Requirements ("LRR") (i.e., the amount of local resources to maintain an expectation that at maximum once every ten years there will not be enough resources to meet the load) are provided; and on page 31, the seasonal MISO wide PRMR% (UCAP) are also provided. On an annual basis for LRZ 6's and hence CEI South's, PRMR is given by the MISO System Wide PRMR. In MISO each LRZ needs to meet the largest of the MISO System-wide PRMR or a local reserve level called the Local Clearing Requirement (LCR), calculated as the Local Reliability Requirement less the LRZ's ability to import resources from MISO, which is given by the Zonal Import Ability (ZIA). Maintaining LRZ 6's Zonal Import Ability ("ZIA"), it is possible show that on a seasonal basis LRZ 6's PRMR should be given by the MISO System Wide PRMR, i.e., it is greater than LRZ 6's LCR. The figure below shows an illustrative impact of a MISO seasonal PRMR (UCAP based) of 7.1% in Summer, 18.5% for Winter, 22.3% for Spring and 13.8% for Fall for the 2030 demand and as before a comparison is made with the available resources. As can be observed the highest requirements occur in January, May, August, and September and are met by the available portfolio resources on those seasons. The only exception to the above is the Renewable 2030 for winter which may need to acquire a small amount of additional market capacity (~44 MW) to meet the requirement.

[24] RAN Reliability Requirements and Sub-annual Construct (misoenergy.org): https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf.

## Figure 10

**Renewable + Flexible Gas Portfolio Demand, Reserves and Resources (MW).**




## Figure 11

**Renewable 2030 Demand, Reserves and Resources (MW).**

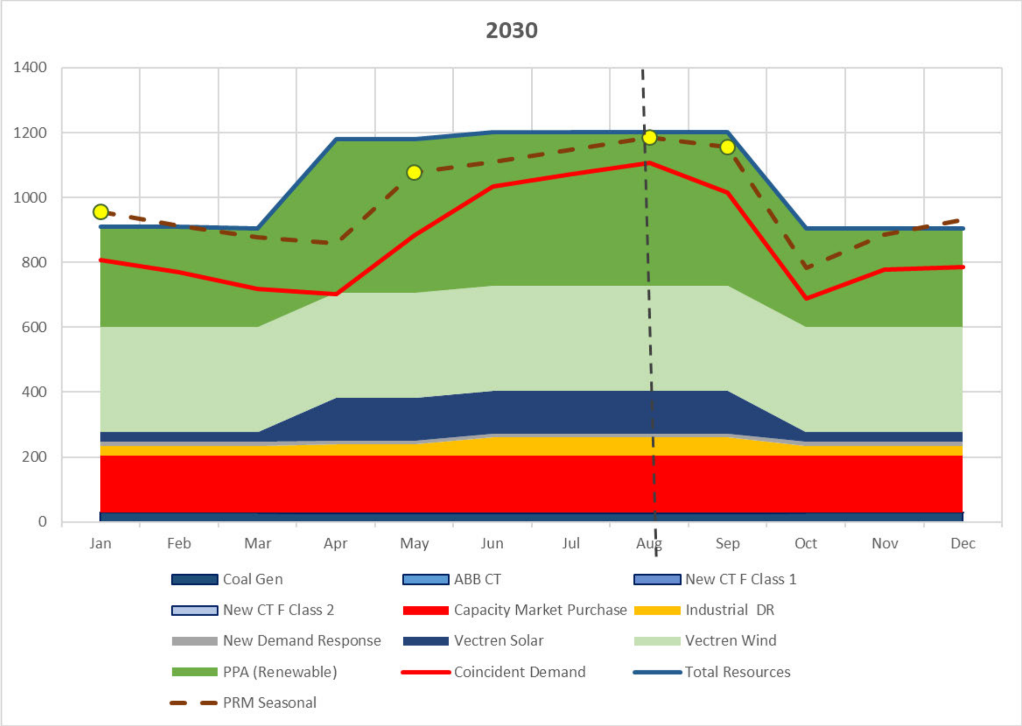
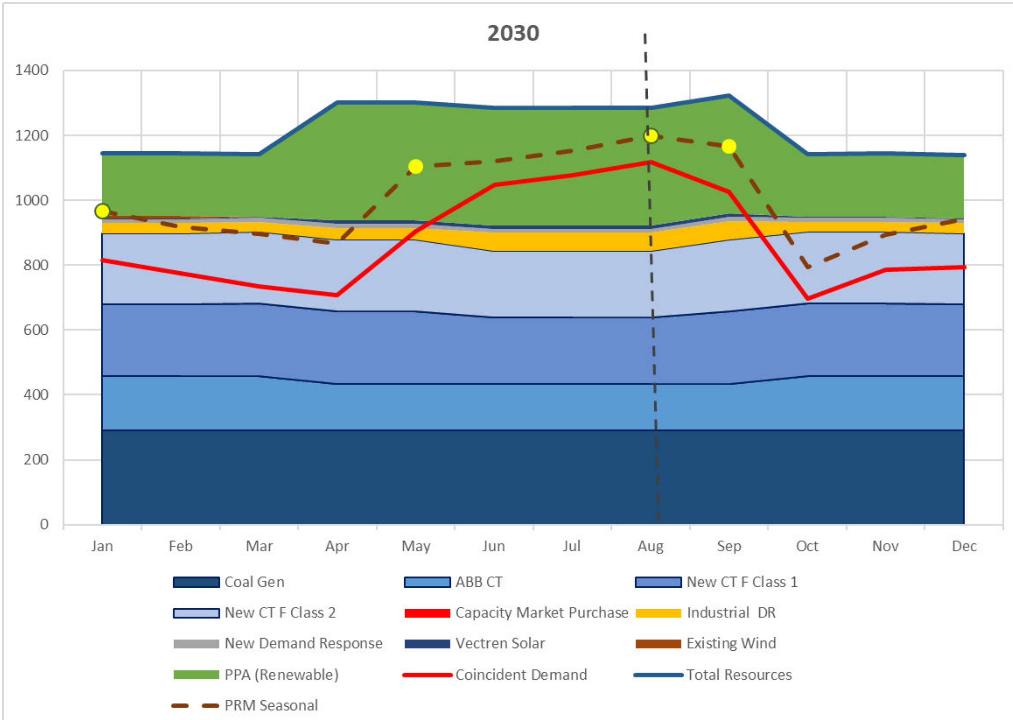


**Figure 12**

**High Technology Portfolio Demand, Reserves and Resources (MW).**



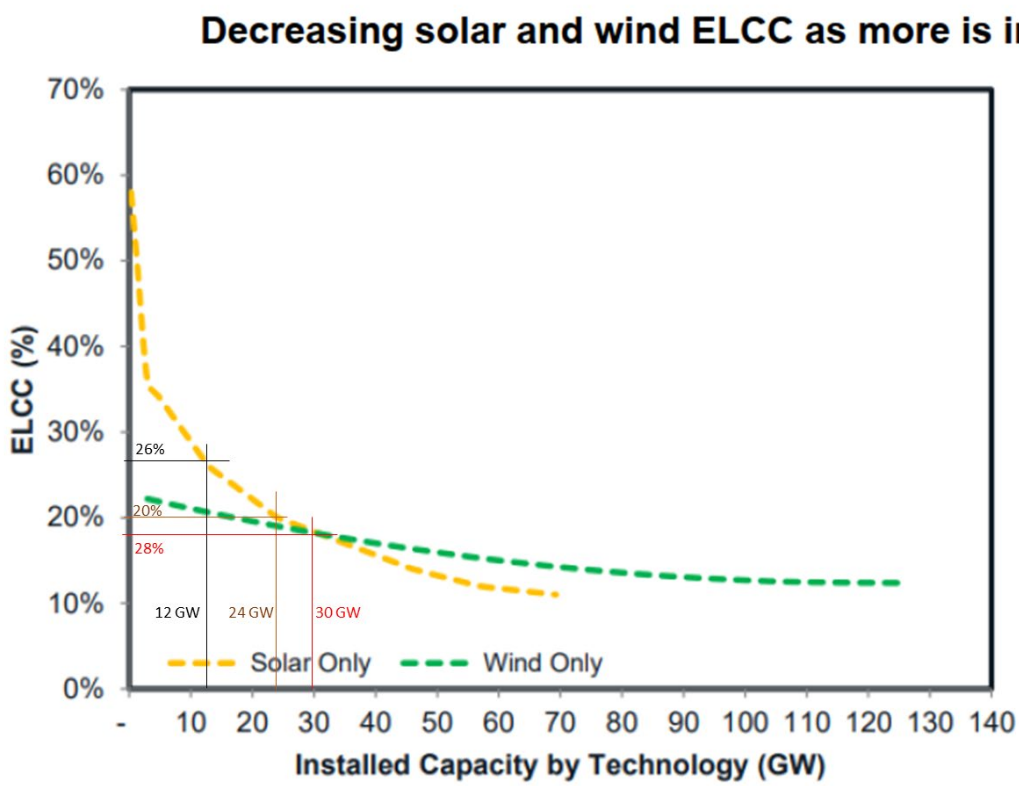

In summary the analysis above leads me to the conclusion that CenterPoint Indiana South's Preferred Portfolio as defined should fare well under a seasonal construct as well. Note again, the red band on Renewable + Flexible Gas and Renewables portfolios that show the capacity purchases, compared to the Preferred Portfolio.

Q **As stated in "Response of CAC, Earthjustice, and Vote Solar to the Director's Draft Report for Vectren's 2019/2020 Integrated Resource Plan", do you agree that the ELCC of Solar and Wind is understated and if CenterPoint Indiana South had used more appropriate values only one CT would be necessary?**

A. No, as I mentioned earlier the ELCC of renewable resources and storage decreases with the penetration and in this context, penetration is the amount of generation installed in the system as a whole, in this case MISO, not LRZ 6 or CEI South. For 2025 CenterPoint Indiana South used a ELCC for solar of 26% for summer and 6% for winter and reducing to 20% Summer and 4% winter for 2033, which is aligned with reasonable forecast of solar. As shown in Figure 5-5 of the IRP, derived from MISO´s Renewable Integration

Impact Assessment (RIAA) Assumptions Document and reproduced below[25], we see that MISO expects that solar will have an ELCC of 26% by the time the solar generation installed in its footprint reaches slightly over 12 GW and a value of 20% by the time the solar generation installed reaches slightly over 24 GW.

**Figure 13**




It is reasonable to expect that the higher rather than the lower forecast will materialize. By the end of 2020 MISO there were approximately 1,492 MW of solar generation in its footprint[26] and over 36 GW of solar in its interconnection queue[27]. Based on this alone it is reasonable to expect that by 2025 there will be more than 12 GW of solar in MISO's footprint and that by 2033 there should be 30 GW or more.

[25] See MISO Renewable Integration Impact Assessment (RIIA) assumptions document V6, https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v7429759.pdf.
[26] Planning Year 2020-2021 Wind and Solar Capacity Credit (https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf).
[27] See MTEP 2020 pg. 23 https://cdn.misoenergy.org//MTEP20%20Full%20Report485662.pdf.

However, this is not the only evidence I see of the reasonableness of this assumption. MISO's Futures, which have the goal to provide bookends for the different generation technologies[28], forecast that for 2033 there will be a minimum of 7.2 GW of Solar on the pessimistic Limited Fleet Change ("LFC") Future, increasing to 13.5 GW of Solar in the Continued Fleet Change ("CFC") Future, 30.4 GW of Solar in the Accelerated Fleet Change ("AFC") Future, reaching a maximum of 42.7 GW in the Distributed and Emerging Technologies ("DET") Future. This is a quite wide range, but once combined with the status of the interconnection queue and the current tendency for an acceleration of solar generation as municipalities, states and utilities address the challenges of climate change; it stands to reason that the future solar generation should be more aligned with AFC or even the DET forecasts.

Hence and looking at the figure above we see that with 30 GW or more of solar in MISO's system a solar ELCC of 20% or lower is to be expected.

For winter, MISO currently uses a solar ELCC of 5%[29] and this will reduce as penetration increases.

Based on the above, I disagree with the statement that on the High Technology Portfolio there would be adequate reserves with only one CT. To illustrate this, I show below the gap between the Total Resources (blue curve) and capacity needs (dotted brown curve) for 2033 using the illustrative seasonal PRMR. As can be observed there are gaps across all seasons.

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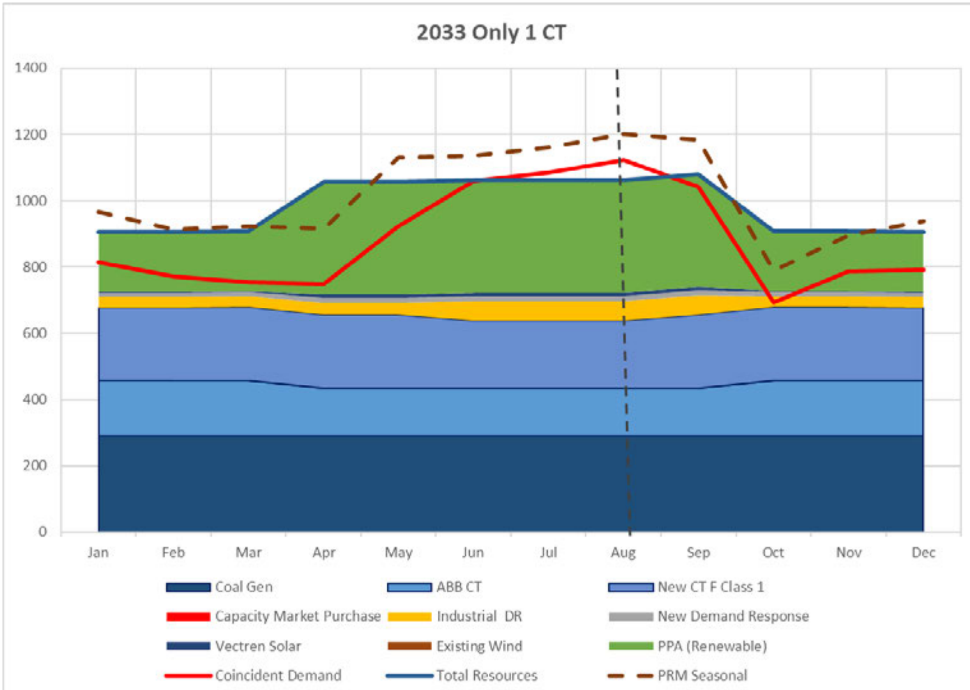
[28] See MTEP 2020 pg. 28 https://cdn.misoenergy.org//MTEP20%20Full%20Report485662.pdf.
**[29]** See page 24 of MISO RAN Reliability Requirements and Sub-annual Construct (misoenergy.org):
https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf.

**Figure 14**

**High Technology Portfolio Demand, Reserves and Resources (MW); 2033 with One CT.**




## III. CONCLUSION

**Q. Does this conclude your direct testimony in this proceeding?**

A. Yes, at the present time.

**VERIFICATION**

I, Nelson Bacalao, under the penalty of perjury, affirm that the answers in the foregoing Direct Testimony are true to the best of my knowledge, information and belief.

Nelson Bacalao
Principal Consultant, Siemens PTI

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Ingenuity for life

PTI Consulting

# Nelson Bacalao

## Principal Consultant

### Career Highlights

Dr. Bacalao has over 35 years of extensive experience in providing technical and strategic consulting services to utilities, governments, regulators, independent project developers, and the financial community, in the US and internationally. He combines a rigorous academic training in engineering and business with utility, government and consulting experience in the technical, economic, and regulatory aspects of utility systems.

Dr. Bacalao core competencies are in the areas of Production costing and Market Analysis, Transmission and Distribution planning, with recent year's emphasis in the Integrated Resources Planning Studies, the integration of renewable generation and system resiliency. Dr. Bacalao also provides expert testimony in support of regulatory processes and the approval of IRPs by regulatory commissions.

### Experience

Dr. Bacalao specializes in utility operations and planning. He has provided due diligence evaluation and/or assessment of transmission and distribution utilities for banks, investors and utility management for more than 30 transmission and distribution companies in 11 countries.

His consulting engagements typically include one or more of the following tasks: (a)system studies, i.e. load flow, stability and reliability, (b) market studies including production cost, and congestion analysis, (c) Review of generation and transmission capital cost forecast, load forecasts and fuel forecasts, (d) Formulation of long term generation capacity expansion plans, including the effects of DER, Battery Energy Storage System, Energy Efficiency and Electrification, (e) Revenue estimation, evaluation of rate structure and assessment on return on investments, and (g) formulation of medium and long-term strategic plans.

Given the difficulty of transmission planning in deregulated electric sectors and the special intermittent nature of renewable generation, Dr. Bacalao has developed strong transmission planning experience under uncertainty. He has performed or supervised numerous studies of this type for systems including voltages up to 765 kV. In these studies, Dr. Bacalao conducted or managed the system evaluations including the formulation of transmission expansion options, load flow and stability studies, production costing impact and, most importantly, the risk evaluations to determine minimum "regret option" and hedging strategies.

Dr. Bacalao has managed or participated in the development of Integrated Resource Plans, feasibility evaluations and technical due diligence analyses of numerous electric generation projects. These studies have included: definition of optimal plant sizes and timing (capacity expansion plans), system impact studies and feasibility (transmission interconnection definition), estimation of capital expenditures and construction time, definition of financing strategy, projection of fuel and non-fuel costs, and production of projected financial pro forma statements.

Dr. Bacalao has solid experience in regulation for the energy industry, with emphasis on grid codes reviews, transmission tariff formulation and periodic reviews. He has provided these types of services to regulators, investors and utilities in countries as diverse as the USA, Puerto Rico, Guyana, Mexico, Turkey, Malawi, Belize, Venezuela and South Africa.

Dr. Bacalao has solid experience in regulation for the energy industry, with emphasis on transmission tariff formulation

Dr. Bacalao has worked in countries across the globe for such multilateral institutions as the World Bank, the Overseas Private Investment Corporation (OPIC), and the Inter-American Development Bank (IDB).

## Areas of Expertise

- Transmission Planning
- Generation Expansion Planning
- Generation Interconnection Studies
- Distribution System Planning
- Capital Expenditure Evaluations
- Operating Expenditure Evaluations
- Financial and Economic Modeling
- Due Diligence Evaluations
- Load Forecasting
- Uncertainty and Risk Considerations
- Resiliency assessments
- Generation Transmission Deliverability Studies
- Production Costing
- Hydro-Thermal Dispatch Forecasts
- Optimal Thermal Unit Commitment
- Estimation of Renewable Generation Impacts on Ancillary Services such as Frequency Regulation, Load Following and Reserves
- Hydro-thermal Scheduling

## Education

- MBA level program, Advanced Managerial Program (PAG-VII) Instituto de Estudios Superiores en Administración (IESA), Caracas, Venezuela, 1990
- PhD, Electrical Engineering, University of British Columbia, Vancouver, BC, Canada, 1987
- Master Engineering (Electrical), Rensselaer Polytechnic Institute, Troy, NY, 1980
- Electrical Engineer, Universidad Simón Bolívar, Caracas, Venezuela, 1979

## Professional Memberships

- Member of the IEEE and its Power & Energy Society
- Member of the Colegio de Ingenieros de Venezuela

## Languages

- English
- Spanish

## Publications

1. "The Role of HVDC in Wind Integration in the Grid of the Future," presented at the CIGRE US National Committee 2012 – Grid of the Future Symposium, Kansas City, MO, October 28 – 30, 2012 (co-authors: W. Galli, A. Landon, and M. Korytowski).
2. "An Efficient Method for Planning Low Voltage Secondary Distribution Networks: Selection of Transformer Ratings and Conductor Types," presented at the DistribuTECH Conference and Exposition, Tampa, FL, March 23, 2010 (co-authors: J.C. Ledezma and P. Duvoor).
3. "Considerations on the Use of HVDC for CREZ Transmission," presented at the IEEE 2009 Power System Conference and Exhibition, Seattle, WA, August 2008 (co-authors: W. Galli, M. Hutson, and R. Nadira).
4. "Measuring the Performance of Distribution Utilities - A Top-Down/Bottom-Up Approach," in *Proc. 2006 IEEE PES Latin American T&D C&E*, Caracas, Venezuela (co-author: R. Nadira).
5. "Strategic Assessment of Supply Options in Power Systems with Significant Supply Uncertainty," in *Proc. Probabilistic Methods Applied to Power Systems (PMAPS-2004)*, September 12-16, 2004, Iowa State University, Ames, IA, pp. 867-872 (co-authors: R. Nadira, H. Fendt, C. Dortolina, and J. Di Bella).
6. "Supply Risk Analysis in Electricity Markets from the Perspective of a Large Customer," in *Proc. 2004 IEEE PES General Meeting*, Denver, CO, June 2004, pp. 180-185, vol. 1 (co-authors: H. Fendt, R. Nadira, C. Dortolina, and J. Di Bella).
7. "PCAP Program Adapted for Islanding Studies: Integrated Resource Planning in Developing Countries - A Novel Approach," presentation in panel session of IEEE PES General Meeting, Denver, 2004 (co-authors: C. Dortolina and M.P. De Arizón).

8. "Evaluation of Transmission Tariff Methods in Restructured Power Markets," in *Proc. IEEE 2003 PES General Meeting*, Toronto, ON, Canada, July 2003, vol. 2 (co-authors: R. Nadira, H.M. Merrill, and C. Dortolina).
9. "Evaluation and Design for Compact Transmission Lines," 4th Jornadas Hispano-Lusas, Oporto-Portugal, July 1995 (co-author: M.P. De Arizón).
10. A Model for the Synchronous Machine using Frequency Response Measurements," IEEE, San Francisco, CA, 1994 (co-author: M.P. De Arizón).
11. "Study for the Insulation Level Optimisation of 230 kV and 115 kV Substations," IEEE, Latincon 1992 (co-author: M.P. De Arizón).
12. "A New Methodology for the Optimisation of Insulation Levels in 230 kV and 115 kV Substations," CIGRE, Argentina, 1991 (co-author: M.P. De Arizón).
13. "Transient Stability Studies for the Venezuelan Bulk Transmission System Considering HVDC links," Erlac-Cigre Foz de Iguazu, Brazil, 1988 (co-authors: G. Pesse, J.M. Aller, M.P. De Arizón, and A. Negrin).
14. "Optimal Tuning of Power System Stabilizers," IV Power System Congress, Puerto La Cruz, Venezuela, 1986.
15. "Fast Stability Simulations Based on Frequency Responses," IV Power System Congress, Puerto La Cruz, Venezuela, 1986.
16. "Modeling of an HVDC Link in a Load Flow and Stability Program," IV Power System Congress, Puerto La Cruz, Venezuela, 1986.

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