located in LRZ 7; and (5) maximum PPA length of seven years beginning June 1 of any year between 2018 and 2022. *Id.*

Ms. Dimitry testified that the company requested bids on PPAs up to seven years "to gain insight on short term capacity options" and to "provide[] a bridge to the expected timeframe for the next round of coal plant retirements for the Company, which will trigger a new assessment of energy and capacity needs and possible solutions." 6 Tr 1615.

Ms. Dimitry opined that DTE Electric's bid requirements were reasonable for any third-party considering building generation or offering a PPA. According to her, a project could be completed by 2022, the locational requirement reflects resource adequacy rules, and merchant generators are able to obtain financing without long-term contracts. In addition, Ms. Dimitry testified that "[t]he Company also believes that a shorter PPA term minimizes the risks of misaligned incentives between the Company and a PPA supplier[,]" further explaining that additional risks of long-term contracts include: (1) risk that the counter-party will fail to perform; (2) risk of contract termination; (3) reduced operational flexibility; (4) change of ownership of the generating facility; and (5) balance sheet impacts because financial markets view long-term contracts as liabilities. 6 Tr 1616-1617.

Ms. Dimitry testified that DTE Electric received three bids in response to the RFP, one of which did not conform to the size requirement. One bid, offering a 1,100 MW unit was evaluated and was found to have a higher NPVRR than the proposed project. 6 Tr 1619, Exhibit A-2. Ms. Dimitry indicated, however, that the company is still considering the bids in the event the company requires some incremental capacity as plants retire. 6 Tr 1620.

Mr. Olling testified that the MCV did not participate in the competitive bid process because DTE Electric would not consider a PPA longer than seven years, despite the company's proposal to build a plant with an operating life of 30 years or more. Specifically, Mr. Olling testified that in response to DTE Electric's RFP, the MCV sent a letter requesting additional information necessary to develop different PPA options. 5 Tr 610, Exhibit MCV-1. According to Mr. Olling, DTE Electric responded by indicating that a long-term PPA would not be comparable to a self-build option and failing to provide any answers to the MCV's request for additional information. 5 Tr 611, Exhibit MCV-2. Mr. Olling stated that because DTE Electric refused to consider any PPA term beyond seven years, the MCV determined that it would be fruitless to respond to the company's RFP. Contending that DTE Electric failed to comply with the requirements of Section 6s, Mr. Olling posited:

> By categorically ruling out a long-term PPA commencing with the anticipated in-service date for the Company's self-build option, the Company foreclosed competitive proposals from merchant generators such as MCV that would require a similar lead-time to obtain permits, complete construction, and achieve commercial operation for new generating facilities. The Company thereby established RFP criteria that could not produce comparable alternatives to its preferred self-build approach.

5 Tr 613.

In response to Ms. Dimitry's claims about the risks associated with long-term PPAs, Mr. Olling points out that "company ownership . . . does not alleviate performance risk" further noting that DTE Electric failed to address the risk to its customers in the event the proposed project becomes obsolete before the end of its useful life. 5 Tr 618. Mr. Olling stresses that the remaining risks cited by Ms. Dimitry can be addressed through contract negotiations. With respect to balance sheet risk, Mr. Olling opined that such risk:

> . . . is shorthand for stating that the Company believes its shareholders would be better off by building a plant that can be included in rate base and upon which it can earn a return than they would be if the Company enters into a long-term power purchase agreement. Ms. Dimitry does not claim to have any financial experience with public utility credit ratings or the metrics that ratings agencies apply. She does not discuss the balance sheet implications of the Company's self-build option, or

> the fact that financing the roughly $1 billion cost to construct a 1,100 MW power plant would likely involve issuances of both debt and equity by the Company.

5 Tr 620. Mr. Olling continued, citing specific risks associated with the self-build option including construction cost overruns, plant performance, lack of adaptability under utility ownership, and permanent loss of the asset. Mr. Olling testified that DTE Electric did not account for these risks in its IRP. 5 Tr 621.

Mr. DiDomenico questioned why DTE Electric's RFP resulted in few bids:

> An 1,100 MW facility with an initially estimated cost of $989 million is a significant investment opportunity, and it is very reasonable to expect that far more qualifying bids would have been received. The lack of a robust market response to meet an 1,100 MW generating station need requires a very close examination of the RFP requirements and overall process to determine whether the scarcity of qualifying bids simply reflects competitive market conditions or whether some peculiarities related to the RFP chilled the market for alternatives in this case.

6 Tr 1568. He opined that DTE Electric's decision to restrict bids to resources located in LRZ 7, coupled with the seven-year PPA term, likely limited the response to the RFP, like Mr. Olling, noting the inconsistency between the short PPA length and the 30-year operating life of the proposed project. Mr. DiDomenico concluded that, "the Commission has ample grounds to seriously question the competitiveness of the market testing of the alternatives to the Self Build option," 6 Tr 1569. Accordingly, he made the following recommendations for future solicitations:

> I recommend that the Commission require that proposed resource RFPs be submitted at least 90 days in advance of issuance with an opportunity for stakeholders to provide comments on the proposed form, ground rules, timeline and other requirements of the RFP. The Commission could then consider these concerns before approving an RFP for a company to issue. Review and approval of an RFP in advance of issuance would enhance openness, fairness and transparency of the process, and should result in a more robust and competitive market response.

Id.

Ms. Simpson also testified that while the Staff acknowledged there is some risk to a long-term PPA, the company's proposed project also entails risk. Ms. Simpson indicated that PPA shortcomings could largely be addressed by careful contracting. 5 Tr 200.

Although the Commission's CON and IRP guidance does not include a requirement to conduct competitive bidding as an alternative to the proposed project, or details on how such bidding should be conducted, the Commission views competitive bidding as a standard business practice to ensure cost-effectiveness. It is integral to determining whether the proposed course of action is the most reasonable and prudent option by testing market response to alternatives.

The Commission has significant concerns with DTE Electric's RFP and bidding process particularly for a PPA option. The Commission agrees with the Attorney General that, given the size and expense of the proposed project, one would have expected a more robust market response to the solicitation. The Commission also believes that although there may have been opportunities to enter into a PPA, DTE Electric's insistence that any PPA be limited to seven years may have dampened potential responses. But, as DTE Electric, the Staff, and the Attorney General point out, under Section 6s(13), an existing supplier that meets the qualifications under that subsection may submit a proposal directly to the Commission; however, no alternative proposals were presented. Moreover, the Commission has not established guidelines or processes for Commission review of RFPs or bid evaluation (outside of renewable energy program) and DTE Electric provided a reasonable explanation for including certain constraints in the RFPs due to various risks. As Ms. Dimitry explained, "the financial exposure to the Company and its customers in the event of a counterparty default for a PPA of this magnitude could be significant. . . . In this instance, the Company and its ratepayers are at a significant risk if the level of financial remedy within the contract does not match the Company's penalties, or if the Company is unable to collect from the counterparty." 6 Tr 1627.

In light of Commission's findings on this issue, and the importance of ensuring confidence by third parties in the integrity of any RFP processes in the future, the Commission adopts in part the Attorney General's recommendation that the Commission provide more oversight of future RFPs that may be used to support a CON or IRP. Specifically, the Commission agrees that any proposed RFP should be submitted to the Commission at least 90 days before issuance for review by the Staff. As the energy industry continues to evolve and new technology solutions emerge, including solutions that may involve greater engagement of end-use customers or integration with the transmission or distribution system, it is also important to ensure that RFPs are truly open to allow a broad range of potential solutions to be considered. While this will make the bid evaluation process more complicated, it can avoid RFPs inadvertently placing barriers on options such as energy storage that could provide multiple values or attributes.

The Commission expects competitive bidding to be of increasing importance for the selection of resources and the approved amounts under the pre-approval provisions of CONs and IRPs. Accordingly, the Commission directs Staff to research approaches and best practices for RFP and competitive bidding in other jurisdictions.

7. Electric transmission options for the electric utility.

In his initial brief, the Attorney General explained that, with respect to resource adequacy requirements:

> When sufficient transmission import capability is not available, [load serving entities] LSEs within a transmission import-limited LRZ may be forced to rely more on capacity located inside the LSE's zone even though lower cost resources may be available outside the zone. Besides the system wide PRMR, MISO produces a LRZ specific PRMR which must be met by the LSEs within the zone. All the LSEs and utilities within the MISO region have the flexibility to meet their

respective PRMR by using a combination of self-supply, bilateral contracting, and residual procurements through MISO's centralized Planning Resource Auctions ("PRAs"). Besides the system wide and LRZ specific PRMR, MISO produces every year LRZ specific parameters.

MISO is obligated to calculate the following LRZ specific parameters on an annual basis : (i) Local Reliability Requirement ("LRR"), (ii) Capacity Export Limit ("CEL"), (iii) Capacity Import Limit ("CIL") and (iv) Local Clearing Requirement ("LCR"). The LRR represents the amount of resources needed by a LRZ to reliably meet its forecasted peak load without the benefit of imported capacity. CIL and CEL provide the maximum amount of capacity that can be imported –CIL –or exported –CEL-from a LRZ after respecting the established MISO reliability standards. LCR is the LRR reduced by CIL (LCR = LRR –CIL). These four parameters define system constraints and are used by MISO during the PRA in a way that capacity is procured in the most cost-efficient way while respecting resource adequacy and transmission reliability standards.

Attorney General's initial brief, pp. 8-9.

Mr. Weber testified that import capability into DTE Electric's service territory is currently constrained due to the loss of the major east-west 345 kilovolt (kV) lines into that territory. Mr. Weber indicated that he had reviewed the MISO transmission expansion plan for 2014 (MTEP-14) considering any projects with an in-service date of 2025. According to Mr. Weber, "no approved projects existed that would expand firm import capacity." 7 Tr 2171.

Mr. Osborn testified that DTE Electric has access to three electric markets: MISO, PJM, and Ontario. Mr. Osborn noted that the connection between MISO Zone 7 and MISO Zone 6 is fairly narrow and consists of a 345 kV MISO transmission line and several 345 kW transmission lines from PJM. 5 Tr 508. Currently, according to Mr. Osborn, there is an underutilization of imports from PJM to Zone 7, which results in higher costs for Michigan customers. Mr. Osborn opined that this was the result of Michigan utilities focusing more on in-state generation rather than on interconnection with the rest of the grid. 5 Tr 514. Mr. Osborn further observed that PJM has significant excess capacity for 2023 through 2029. Exhibit MEC-76. Thus, Mr. Osborn testified that lower-cost imports from PJM could defer or replace DTE Electric's proposed project. 5 Tr 514-515.

Mr. Osborn testified that in addition to the possibilities presented by the PJM market, Zone 7 is also interconnected with the Ontario independent system operator (IESO). According to Mr. Osborn:

> A recent MISO analysis found a Total Transfer Capability from IESO to MISO Central of 2,487 MW, more than double the capacity proposed in the CON. Ontario also appears to have energy that is not used by markets: IESO makes ongoing short-term projections of resource adequacy that report thousands of MW of excess capacity and thousands of MWh of excess energy.

5 Tr 517. Mr. Osborn further observed that Ontario prices are typically lower than Michigan's, concluding that it would be reasonable and prudent to evaluate imports from Ontario as an alternative to the proposed project.

In addition to the possibility of imports from Ontario, Mr. Osborn testified that that IESO is interconnected with Hydro Quebec, a winter-peaking utility with approximately 6,000 MW of excess summer capacity that can be exported. DTE Electric, on the other hand, has approximately 4,000 MW of excess winter capacity, raising the potential for power exchanges between DTE Electric and Hydro Quebec. 5 Tr 519.

Mr. Osborn disagreed with Mr. Weber's claim that the transmission into Michigan is currently constrained, contending that "Mr. Weber was not relying on current information about the state of the system." 5 Tr 520. Mr. Osborn observed that the constraint to which Mr. Weber was referring has been addressed, and "the 2017 MTEP Book 2 now list the Capacity Import Limit constraint for Zone 7 as being south of Detroit rather than on the east-west 345 kV line." 5 Tr 522, Exhibit MEC-84. With respect to the constraint south of Detroit, Mr. Osborn testified:

> Exhibit MEC-85 is a presentation from the December 6, 2017 1st East Subregional Planning Meeting for the MTEP18. Pages 10-11 of the presentation list two

> projects to address this transmission constraint. The projects are potential upgrades to the 345kV station equipment at Brownstown and Monroe, and at Monroe and Wayne. They have costs of $1.076 million and $580,000, respectively; and in - service dates of 2020 and 2018, respectively. Further studies will determine if the potential upgrades will be submitted for approval for construction.

5 Tr 523-524 (footnotes omitted). If additional import constraints develop in the future on the 345 kV east-west line, Mr. Osborn indicated that the retirement of the Palisades Nuclear Plant in 2022 may relieve these constraints. 5 Tr 524.

Mr. Osborn also disputed DTE Electric's reliance on the MISO CIL as a reason that firm transmission is not an option to defer or displace the proposed project. Mr. Osborn testified that "[t]he CIL restricts general imports from other MISO zones, such as through capacity auction purchases. It does not, however, apply to the import of power from a specific source or sources outside of MISO." 5 Tr 524-525. Mr. Osborn nevertheless acknowledged that if there were a capacity constraint, it would still need to be addressed through a Transmission Service Request, "a specific study, which DTE has apparently neither sought nor carried out." 5 Tr 525. Mr. Osborn explained that the CIL is a limitation on the amount of power that can be imported from one MISO LRZ to an adjacent LRZ and is not an expression of transmission limitations. 5 Tr 525-526. Mr. Osborn explained that transmission upgrades may not be necessary for DTE Electric to secure firm import, however, DTE Electric never explored this option. 5 Tr 528.

Mr. Berkow sponsored a transmission study, set forth in Exhibit MEC-89, which showed that the current transmission interface between Michigan and IESO is currently controlled by phase angle regulators (PARs) at three substations. According to Mr. Berkow, "It is possible that the PARs could change their operation to increase import capability of power from IESO into Michigan; however, additional analysis by ITC (the owner of the PARs on the United States side) and MISO would need to be performed to verify." 5 Tr 548. Without the ITC and MISO analyses, Mr. Berkow assumed a new high voltage direct current (HVDC) converter station could be built, to import 1,500 MW of capacity from Ontario into Michigan. Mr. Berkow testified that the cost of the HVDC converter station and transmission upgrades would be $320 million; however, [i]f the PARs are able to be used to their rated capacity, and the Ontario system is able to be dispatched to avoid the transmission upgrade, total cost would be just $15 million for the Michigan transmission upgrades." 5 Tr 549.

In rebuttal, Mr. Weber averred that DTE Electric undertook the required transmission studies set forth in the IRP guidance. With respect to transmission options, Mr. Weber testified that "I examined any projects with an in-service date of 2025 in the MTEP14 database and subsequent MTEP projects in close proximity to the proposed project. The results of the analysis were that no approved projects existed that would expand firm import capacity." 7 Tr 2171. Mr. Weber also pointed out that MEC/NRDC/SC failed to present any transmission alternatives that would constitute a viable option. He added:

> Any new transmission to relieve Michigan congestion or to increase import capability would require a lengthy study conducted by MISO through their MTEP and congestion study processes, and potentially the MISO-PJM Interregional Process. Additionally, it is important to understand that DTE Electric is not a transmission owner and does not possess the unilateral authority to compel MISO to approve transmission modifications.

7 Tr 2172. Mr. Weber concluded that:

> None of the high-level transmission modification ideas to address firm transmission import constraints, presented in Witness Osborn's testimony, have materialized into project proposals in the MISO transmission planning process. As already stated, DTE Electric does not possess the authority to unilaterally compel MISO to approve such projects, and therefore cannot risk its statutory obligation to serve on the uncertain outcome of the MISO stakeholder process and a decision from the MISO Board of Directors. In addition, the project study process to address firm transmission import constraints can be lengthy and uncertain, and the overall timeframe from study to completion, typically several years as witnessed on similar projects, would likely preclude them from consideration as a viable alternative to

> the proposed project. It is also important to note that any transmission alternatives would only work when a firm generation resource is available to import.

7 Tr 2173.

Ms. Wojtowicz responded to Mr. Osborn's suggestion that DTE Electric could import capacity from outside LRZ 7, testifying:

> If the Company were to rely on capacity from outside of MISO LRZ 7 (from another MISO LRZ or an adjacent RTO) to replace its retiring coal units, reliability in LRZ 7 would likely not meet acceptable standards as there would likely not be sufficient local capacity resources to meet the LCR. Based on recent MPSC Staff projections in Case No. U-18444, LRZ 7 could be as short as 1,407 MW (Exhibit A-55) to meeting the LCR after the retirement of DTE's River Rouge Unit 3, St. Clair Units 1, 2, 3, 6, & 7, and Trenton Channel Unit 9.

7 Tr 2248.

The Commission agrees with MEC/NRDC/SC and the Attorney General that DTE Electric's analysis of transmission options was unnecessarily weak. The Commission is especially concerned that the company chose to rely on an MTEP report that was a year out-of-date at the time of the company's review. As Mr. Osborn pointed out, some of the transmission constraints have been relieved, as a review of more recent MISO material would have shown. Nevertheless, the Commission finds Ms. Wojtowicz's and Mr. Weber's rebuttal persuasive, that given the time requirements for transmission studies and transmission build out, coupled with concerns about the reliability of imported capacity, there is no reasonable and feasible transmission alternative to the company's proposed project.

The IRP filing requirements adopted by the Commission under Section 6s, state "to the extent practicable, the IRP shall include analysis of existing transmission import and export capability, proposed transmission projects, and the availability and economic impact of power imports and exports." December 23 order, Exhibit B, p. 4. DTE Electric technically met this requirement. In the two prior CON cases, the Commission did not address in detail its expectations for consideration of transmission alternatives. In Case No. U-18224, without any challenges from the parties, the proposed plant was determined to be a lower-cost option to transmission upgrades that had been previously identified by the transmission company as necessary absent a local generation solution.

As DTE Electric points out, it has not been a transmission owner since it divested its transmission assets in 2004. And although ITC was a party to this proceeding, neither ITC nor any other transmission owner presented transmission options for Commission consideration. While DTE Electric is not precluded from proposing transmission solutions through the MISO regional transmission planning process, there are limits on the company's ability to identify and pursue transmission alternatives that other entities would need to build and own. Moreover, the import constraints affecting import capacity for LRZ 7, and solutions to these constraints, are not necessarily local, or even within the state, as shown in the MTEP 14, 15, and 16 reports. Therefore, it is challenging for a non-transmission owning utility like DTE Electric to identify, study, and implement transmission solutions, particularly to meet a near-term need. In addition, there is inherent risk in siting and permitting transmission facility upgrades, particularly if they are out-of-state with required siting and regulatory approvals and cost allocation.

Even though it is not a transmission owner, DTE Electric could have conducted a more in-depth investigation of transmission system constraints as well as transmission options to enable delivery of energy resources from outside of the MISO region by further engaging transmission owners and other entities in a stakeholder process. As MEC/NRDC/SC pointed out, the company relied primarily on existing approved transmission projects in the outdated MISO MTEP 14 Report. Mr. Osborn included references and exhibits in his testimony to more recent MISO loss os load expectation (LOLE) reports and MISO MTEP 16 that clearly indicate different constraints than those that existed in 2014. *See*, Exhibit MEC-84 and MEC-73.

Although Mr. Osborn and Mr. Berkow provide several transmission possibilities that may allow for energy resources to flow into LRZ 7, those options are not coupled with any currently qualifying external resources in MISO. According to Ms. Wojtowicz, external resources could count toward the Zone 7 LCR to the extent that those resources are willing to comply with MISO's rules. 7 Tr 2264. Because there aren't any existing, already qualified, external resources in MISO that could potentially meet DTE Electric's needs, coupled with the potentially changing MISO rules surrounding external resources as evidenced in a recent FERC filing by MISO in Case ER18-1173, significant risk surrounds the concept of relying on potential yet-to-be qualified external resources to meet near-term capacity needs.

With DTE Electric's planned coal plant retirements, and without the proposed 1,100 MW NGCC plant or other alternative new planning resources counting toward the LCR in 2022 and 2023, Zone 7's resource adequacy projections would be stark. Based on the Staff's Report in Case No. U-18441, and adjusting for the retirement of DTE Electric's coal plants, Zone 7 would be at risk of falling short of its LCR requirement by up to 716 zonal resource credits (ZRCs).[13] Falling

[13] The Staff's March 6, 2018 Report and Recommendations in Case No. U-18441 shows an LCR demonstrated position of 929 ZRCs for planning year 2021/22 for Zone 7. However, subtracting 1215 ZRCs for the retirement of the St. Clair units results in negative 716 ZRCs. In Case No. U-18444, Staff has indicated that concerns about Zone 7 not meeting the LCR are diminished because of the Staff's assumption that local utilities, due to inherent incentives to earn a return on capital investments, will build new generation in the zone (and other options) to replace retiring coal plants and the Palisades nuclear power plant when it is planned for closure in the early 2020s. See Staff's Initial Brief in U-18444, p. 14. If DTE Electric does not construct the 1,100 MW facility or otherwise ensure an equivalent amount of local planning resources in the zone (or defer the plant retirements), the LCR outlook would be decidedly uncertain given the lack of any public announcements to build generation in the zone.

below the LCR in the zone means that Michigan would not be meeting federal reliability standards, and it increases the probability of an outage due to inadequate supply. The Commission acknowledges that other local demand- and supply-side resources could help fill this gap without a new gas plant but as discussed above, there is uncertainty with the ability to scale EE and DR to the levels that would be needed in this timeframe, and uncertainty around the default and actual capacity credit of other resources such as solar under MISO rules. In addition to the risk of not meeting the LCR requirements in Zone 7, DTE Electric would likely fall significantly short of meeting its required PRMR without replacing the retiring coal plants with other planning resources. DTE Electric will indeed find itself in need of adding capacity resources to meet its capacity demonstration requirements pursuant to Section 6w, as well as planning reserve margin requirements at MISO.

There are also potential local operational reliability challenges associated with coal plant retirements if there is inadequate local generation to provide voltage support and other reliability support to the transmission grid. DTE Electric has submitted early requests to MISO to study any reliability impacts associated with the retirement of the Tier 2 units. The results of these studies were not available for inclusion in this record, but there are numerous instances in both the Upper and Lower Peninsulas of Michigan in which coal plant retirements have required new generation or transmission upgrades and/or delayed retirements to ensure near-term operational reliability under different contingencies. It bears emphasizing that reliability and resiliency issues extend beyond the counting of "ZRCs," or capacity credit, under the MISO's resource adequacy requirements and the Commission's implementation of section 6w in Act 341. Reliability is not just about ensuring adequate capacity on the peak summer day. Local generation—unlike all the alternatives presented in this proceeding—provides significant support to keep the grid operational and stable on a minute-by-minute basis, year-round. Michigan's generation fleet is undergoing a significant transformation with approximately half of its coal fleet retiring over the course of about a decade. The Palisades plant, which has been consistently operating nearly non-stop except during re-fueling, is slated to close in early 2022. Consumers Energy is also considering four additional coal unit retirements before 2025.

The Commission finds that this proposed gas plant, while quite large, fills only a fraction of the power needs to be addressed by retiring plants representing thousands of megawatts in the state. Moreover, unlike coal or nuclear or even older gas plants in the state, the proposed gas plant's expected 24/7 availability and ability to ramp output up and down quickly will better position the utility and regional grid operators to integrate additional renewable energy such as wind and solar. As Mr. Lucas pointed out:

> DTE must maintain sufficient capacity to keep its system reliable. Flexibility – both on the generation side and on the demand side – is key. As more variable resources such as solar and wind are introduced, matching supply with demand will require more attention. The ability for generators to respond quickly to changes in solar and wind generation, and to ramp their output up or down, is critical. Additional capacity resources and ancillary services capability from batteries, smart inverters, and synthetic inertia can help smooth the changes in variable energy resources.

5 Tr 758. This plant provides greater flexibility as Michigan moves toward a more diverse portfolio of resources with coal, nuclear, natural gas, wind, solar, biomass, expansions to pumped energy storage, demand response, as well as a strong commitment—on the order of 50% beyond statutory minimums—to energy efficiency.

The Commission encourages DTE Electric to continue to coordinate with MISO and ITC on reliability planning to accommodate the retiring coal plants. In addition, in DTE Electric's 2019 IRP, the Commission expects a far more robust analysis of transmission opportunities that might defer, displace, or optimize the amount, type, and location of additional generation based on up-to-date information about current and expected transmission system conditions and import/export capabilities. To ensure alternatives are fully considered in future IRP proceedings, and the system is optimized from a cost and reliability standpoint, the Commission also expects DTE to work closely and collaboratively with ITC and other transmission owners to explore transmission solutions and to work toward integrating the company's distribution planning efforts with resource planning.

After thoroughly considering alternatives, based on the Commission's findings and conclusions under MCL 460.6s(4), as set forth above, the Commission finds that DTE Electric's proposed project is the most reasonable and prudent means to meet the need for power in 2022. Therefore, the CON requested under MCL 460.6s(3)(b) should be granted.

E. Will the construction of the new facility be completed using a workforce composed of residents of this state?

DTE Electric provided substantial evidence that the construction of the new facility will be completed using a workforce comprised of Michigan residents. Mr. Fahrer testified:

> The total estimated craft labor workforce employed by the EPC Contractor for constructing the Proposed Project is anticipated to involve in excess of 1.5 million work hours with the demand for craft specialties shifting over the duration of the project. Based upon a typical project schedule, the simultaneous craft labor workforce is expected to peak around 520 full time equivalent (FTE) personnel roughly19 months after the start of Construction. In addition to craft labor, EPC on-site construction and management staff is estimated to include an additional 60 FTE[]s to support the construction project.

8 Tr 2614. In addition, Mr. Fahrer testified that there was adequate labor resources available in the state, and he estimated that 90% of the craft labor force would consist of Michigan residents.

The Staff agreed with Mr. Fahrer's estimates, and no other party took issue with DTE Electric's representations on this issue. The Commission therefore finds that the construction of the new facility will be completed using a workforce composed of residents of this state.

F. Summary

In summary, as required by section 6s(4), the Commission thoroughly considered the need for power; compliance with environmental laws; the reasonableness of the estimated cost of power; whether the proposed plant is the most reasonable and prudent option to meet the need relative to other resource options, such as energy efficiency, renewable energy, demand response, energy storage, transmission, PPAs, and any alternative proposals submitted by third parties; and the local workforce associated with the construction and investment in the proposed plant.

This application was examined under CON provisions in section 6s under Act 341, the CON filings requirements updated in May 2017 to conform to revisions to 6s, and the IRP guidelines approved by the Commission after section 6s was first enacted in 2008. Filing this CON under these legal standards and regulatory guidance was not unexpected during the development of the 2016 energy laws and the revisions to the CON filing requirements adopted by the Commission, with input from interested stakeholders, in May 2017. While the new IRP provisions and Commission guidance under section 6t are more detailed and prescriptive, the Commission benefitted from a robust record to make an informed decision under the applicable law in this proceeding. As discussed in this order, deferring such decision to the 2019 IRP filing by DTE Electric presents risks from a cost and reliability standpoint.

The modeling of options and analyses conducted by DTE Electric and the intervenors were extensive and tested many combinations of options to inform this critical decision, particularly the determination of whether the proposed gas plant is the most reasonable and prudent option. Over 70 modeling runs were presented. Given the importance of this decision, it is not surprising that there was significant debate over competing IRP assumptions and methodologies—many of which can have a major impact on the modeling results. While there is inherent risk with any decision of this magnitude and the inquiries to examine alternatives could be nearly endless, particularly with invariably changing assumptions and conditions affecting the energy industry, the preponderance of evidence shows there is a significant near-term need for power and the proposed gas plant – whether it goes into service in 2022 or 2023 – is the most reasonable and prudent option given the standards set forth by section 6s, the Commission IRP and CON guidelines, and the alternatives presented in this record. Aside from the modeling results, the Commission finds that there are important feasibility and grid reliability questions that were not adequately addressed about the near-term viability of various alternatives presented including transmission with imported power, PPAs, and incremental renewable energy and demand-side options. The evidence also clearly indicates that the costs for the plant, adjusted for Staff's lower contingency amount, are reasonable.

DTE Electric met the requirements set forth in section 6s and its applicable guidance for CONs and IRPs for the three requested certificates under MCL 460.6s(3)(a),(b) and (d).

VI. <u>OTHER ISSUES</u>

A. Cost Recovery under MCL 460.6s(3)(d)

Ms. Uzenski testified in support of current recovery of financing costs related to the proposed NGCC plant. Ms. Uzenski explained, that by "current recovery," "I mean that in a general rate case, the costs of construction work in progress [CWIP] for the proposed project, reflected in the projected test year, would be included in rate base without an AFUDC offset. Construction costs not included in rate base (due to regulatory lag) will accrue AFUDC until they are reflected in rate base." 5 Tr 1498. Ms. Uzenski testified that current recovery of financing costs, if approved, would "reduce the total capitalized cost of the asset reflected in rate base, thereby reducing future revenue requirements." *Id.* However, traditional accounting and ratemaking for financing costs would change the timing because financing costs would be accrued as allowance for funds used during construction (AFUDC). AFUDC would then be recovered once the plant is included in rate base. 5 Tr 1499.

Ms. Uzenski testified that there are approximately $400,000 in capital expenditures currently in rate base incurred from 2011 through 2013 and that the company included $6.5 million of capital expenditures and $26.6 million in CWIP, without an AFUDC offset, in the company's then-current rate case, Case No. U-18255. *Id.*

Mr. Nichols testified that the Staff supports the recovery of financing costs related to the proposed NGCC, provided the costs are included in a general rate case and are found to be reasonable and prudent. Mr. Nichols further testified that the Staff supports the company's request for traditional accounting and ratemaking treatment of financing costs in the event the Commission does not approve current recovery of financing costs. 6 Tr 1579-1580.

No party opposed the company's request for current recovery of financing costs for the proposed plant, and the Commission finds that the request should be granted. Because the Commission is granting CONs under Section 6s(3)(a) and (b), the Commission finds that the capital costs of, and the financing plan for, the proposed electric generation facility, including, but not limited to, the costs of siting and licensing a new facility and the estimated cost of power from the new electric generation facility, will be recoverable in rates from DTE Electric's customers.

B. Rate Impact Analysis

MEC/NRDC/SC contend that DTE Electric's rate impact analysis was misleading, because the analysis compared the cost of the proposed project to a no-build option that relies on expensive market purchases. Further, they argue that the CON IRP guidelines do not indicate that the analysis should be based on a comparison, let alone a comparison to a scenario that even DTE Electric admits was not viable.

The Commission finds that DTE Electric's purported rate impact analysis, as described by Mr. Chreston and set forth in Exhibit A-10, could be misleading. The guidelines state: "The IRP shall also present an estimated calculation of average customer rates as a result of the plan." December 23 order, Exhibit B, p. 7. While it is not necessarily unreasonable to compare rates to a "no build option," and the Commission's IRP guidelines in another section call for a "no build" analysis, it is important to be transparent about the actual rate impacts from the proposed plant. The Commission is not required to make any findings with respect to customer rates under Section 6s(4), but nevertheless finds that DTE Electric shall provide a straightforward analysis of how customer rates are expected to change as a result of the Tier 2 unit retirements and the addition of the NGCC plant over the first ten years of operation. The Commission is also interested in understanding the impact to rates if some or all of the unrecovered book value associated with the coal plant retirements were removed from rate base and addressed through securitization or other financial measures, rather than recovery through traditional depreciation schedules. While the Commission is not making a final determination on the unrecovered costs of the retiring plants, it is nevertheless interested in the impact that different options may have on customer rates.

C. NEXUS Pipeline

Mr. Beach and Mr. DiDomenico raised issues concerning the NEXUS pipeline. With respect to increased risks and costs associated with the NEXUS pipeline, Mr. Beach testified:

> [T]he new gas supplies from NEXUS may offset the upward pressure on the market basis that could result from the incremental demand from new gas-fired generation facilities such as the gas plant. However, the fact the DTE is likely to hold capacity

> on NEXUS increases the risks that the gas plant will result in above-market transportation costs for DTE's ratepayers, costs that are not included in DTE's gas forecast. Due to the NEXUS commitment, DTE's ratepayers are not just exposed to the risks of the volatility and uncertainty of the gas commodity market; they also are exposed to the risks of the markets for pipeline capacity in the region – specifically, the risk of whether new pipeline capacity from Michigan to western Pennsylvania and Ohio will be economic.

5 Tr 922. Mr. Beach raised concerns that the significant increase in pipeline capacity to the Marcellus/Utica region could result pipeline expansion that exceeds production. Mr. Beach also explained reasons for excess pipeline build-out. 5 Tr 924. Mr. Beach further testified that, because the long-term cost of NEXUS capacity is half the pipeline's as-billed rate, "The above-market pipeline costs of NEXUS would increase the gas plant's fuel costs by about $0.37 per MMBtu, resulting in a 5% increase in the gas plant's overall costs." 5 Tr 927.

In rebuttal to Mr. Beach, Mr. Swiech testified:

> First, Witness Beach appears to arbitrarily assume that the Kensington to MichCon CityGate basis spread will be 50% of the NEXUS transportation cost, and makes no attempt to support that assumption. Second, Witness Beach incorrectly applies his arbitrary basis spread assumption to the entirety of the proposed plant's approximately 180,000 [dekatherms per day] Dth/d required transportation capacity. He chooses to ignore the fact that only 45,000 Dth/d of NEXUS capacity is incremental to the decision to build the plant. Even if Witness Beach's basis spread assumption is correct, the impact on the levelized cost would only be 1.4% because it only impacts 45,000 Dth/ of transportation capacity. This fact is demonstrated by adjusting the calculation used in Witness Beach's model to only account for 45,000 Dth/d of capacity, and the corrected calculation and result is provided in Exhibit A-67.

8 Tr 2565.

Mr. DiDomenico testified that although supply from the NEXUS pipeline could be used by several of DTE Electric's gas plants, the pipeline is expected to also supply the proposed NGCC plant. 6 Tr 1560. Mr. DiDomenico added that it may be advantageous for DTE Electric to secure low-cost supply and transporting that supply via the NEXUS pipeline, rather than relying on third-party, potentially interruptible, supplies at the Mich Con City Gate. 6 Tr 1561-1562.

Despite the possible advantages presented by the NEXUS pipeline, Mr. DiDomenico stated "I am concerned that this strategy as presented in this filing, ignores the potential mismatch in the timing of the in-service dates for the Company's Proposed Plant versus that of the NEXUS Gas Transmission system[,]" noting that there have been several construction delays already as DTE Electric admits. 5 Tr 1563.

Mr. DiDomenico admitted that DTE Electric has not specifically stated that it intends to rely on the NEXUS pipeline for supply, noting that the company intends to enter into firm transportation agreements with several suppliers. However, according to Mr. DiDomenico, "[m]aximizing use of the NEXUS contract by flowing as much supply as possible by dedicating it to a baseload plant will reduce the average cost of gas per unit, which contributes to lower electric generation costs." Mr. DiDomenico also testified that DTE Electric has not developed plans or cost estimates for how it intends to deliver gas from the interstate pipeline to the NGCC plant, noting that the current distribution infrastructure cannot deliver the volumes required for the project. 6 Tr 1565.

In summary, Mr. DiDomenico opined that there are still some risks associated with the company's plan to obtain firm gas supply. He therefore recommended that DTE Electric develop a contingency plan to address these risks and provide the plan to the Commission for approval.

In rebuttal, Mr. Swiech testified that Mr. DiDomenico misunderstood certain aspects of the precedent contract between the company and NEXUS, noting that DTE Electric intends to submit the contract for Commission approval once the pipeline is operational. 8 Tr 2567. With respect to Mr. DiDomenico's concerns about delays Mr. Swiech testified that the delays were the result of issues at the FERC, but that FERC issued a certificate of public convenience and necessity on

August 25, 2017. Thus, according to Mr. Swiech, the NEXUS pipeline is expected to be in service September 2018. 8 Tr 2568.

With respect to the connection between the interstate pipeline and the proposed project, Mr. Swiech explained that on January 8, 2018, DTE Electric issued an RFP for the interconnection project, with proposals expected by mid-February. Mr. Swiech further explained that the cost of the interconnecting facilities is already included in the transportation costs included in the case. 8 Tr 2570.

ELPC did not address the company's rebuttal in its initial brief and the Attorney General did not address the NEXUS pipeline issue at all in his brief. The Commission finds that DTE Electric adequately addressed the issues related to the NEXUS pipeline in its rebuttal and briefing. Specifically, the Commission observes that Mr. Beach's testimony was speculative, and appears to have been based on a miscalculation of the amount of gas to be supplied to the proposed project by the NEXUS system. In addition, as pointed out by DTE Electric in its brief, the NEXUS pipeline contract is subject to approval in a PSCR proceeding, once the pipeline is in service. Finally, the Commission is satisfied that concerns about delays in the in-service date for the NEXUS pipeline have been resolved and that the interconnection costs between the interstate transmission system and the NGCC plant were included in the transportation costs that were modeled.

D. Michigan Environmental Protection Act

In their initial brief, MEC/NRDC/SC contend that, in addition to state and federal emissions and water discharge requirements, the Commission must also determine that the proposed project complies with MEPA. MCL 324.1705(2) provides:

> In administrative, licensing, or other proceedings, and in any judicial review of such a proceeding, the alleged pollution, impairment, or destruction of the air, water, or other natural resources, or the public trust in these resources, shall be determined, and conduct shall not be authorized or approved that has or is likely to

have such an effect if there is a feasible and prudent alternative consistent with the reasonable requirements of the public health, safety, and welfare.

In *State Highway Comm'n, v Vanderkloot*, 392 Mich 159, 185-186; 220 NW2d 416 (1974) our Supreme Court emphasized that that state agencies must consider environmental impacts in permitting decisions:

> While . . . [MEPA] creates a procedural cause of action, ... [it] also establishes substantive standards imposed upon those engaging in, or likely to engage in, pollution, impairment, or destruction of the air, water or other natural resources or the public trust therein. In relevant part, . . . [it] proscribes such pollution, impairment, or destruction unless it is demonstrated that '. . . There is no feasible and prudent alternative to (the polluting, impairing, or destroying entity's) Conduct and that such conduct is consistent with the promotion of the public health, safety and welfare in light of the state's paramount concern for the protection of its natural resources from pollution, impairment or destruction.' This substantive environmental guideline is applicable to the Commission's administrative condemnation determinations.

The applicability of MEPA to this proceeding is not clear based on existing case law. The Commission recognizes that MEPA applies to agency actions generally, but again observes that DTE Electric's request is not compulsory, and the company may build the proposed plant without a CON. Moreover, the granting of a CON does not authorize the company to actually proceed with construction as it would still need to obtain required environmental permits through other agency proceedings. But given the potential environmental impact power generation sources can have on the environment and how the review of "feasible and prudent" alternatives is an integral part of an IRP in a CON proceeding, the Commission concludes that, in addition to the requirements under Section 6s, it is appropriate to determine under MEPA: (1) whether the proposed project would impair the environment; (2) whether there was a feasible and prudent alternative to the impairment; and, (3) whether the impairment is consistent with the promotion of the public health, safety, and welfare in light of the state's paramount concern for the protection of its natural resources from pollution, impairment or destruction.

MEC/NRDC/SC argue that "When a *prima facie* case of harm or potential harm is established, the entity emitting the pollution must demonstrate that there is 'no feasible and prudent alternative' that would achieve the objective of the proposed action." MEC/NRDC/SC's initial brief, p 11.

DTE Electric strongly objects to MEC/NRDC/SC's "newly-announced MEPA claim" arguing that the claim "fails by MEC/NRDC/SC's own cited authority since MEC/NRDC/SC have not 'established' a '*prima facie* case of harm or potential harm.'" According to DTE Electric, "Indeed, they have not even attempted to make any showing and cite no evidence upon which any such potential harm could be found[.]" DTE Electric's reply brief, p. 9.

In addressing the substance of MEC/NRDC/SC's argument, DTE Electric points to evidence in the record showing that the proposed project will comply with all federal, state, and local environmental regulations, as well as evidence demonstrating that closure of eight coal-fired units, coupled with the proposed NGCC unit, will result in an overall reduction in emissions. 5 Tr 1444-1447, Exhibit A-36. Moreover, DTE Electric posits that no party offered a reasonable and feasible alternative to the proposed project, therefore the NGCC plant should be approved.

The Commission agrees with DTE Electric that a comprehensive view of the company's course of action, which includes the closure of eight coal-fired units and replacement with an advanced-class NGCC, results in lesser harm to the environment than the status quo. Accordingly, the Commission finds that, consistent with the agency requirements under MEPA, there is no environmental impairment as a result of the proposed project, and if there were, there is no reasonable and feasible alternative to the impairment. Thus, the Commission finds the environmental impairment consistent with the promotion of the public health, safety, and welfare in light of the state's paramount concern for the protection of its natural resources.

THEREFORE, IT IS ORDERED that:

A. DTE Electric Company is granted a certificate of necessity pursuant to MCL 460.6s that the power to be supplied as a result of the proposed construction of a 1,100 megawatt natural gas combined cycle unit at the site of the Belle River Power Plant in East China Township, is needed.

B. DTE Electric Company is granted a certificate of necessity pursuant to MCL 460.6s that the size, fuel type, and other design characteristics of the 1,100 megawatt natural gas combined cycle unit represent the most reasonable and prudent means of meeting the power need.

C. DTE Electric Company is granted a certificate of necessity pursuant to MCL 460.6s that the estimated purchase or capital costs of and the financing plan for the 1,100 megawatt natural gas combined cycle electric generation facilities, including, but not limited to, the costs of siting and licensing the electric generation unit and the estimated cost of power from the electric generation facilities will be recoverable in rates from the company's customers.

D. Pursuant to MCL 460.6s(6), the Commission approves $951.8 million for the construction of the natural gas combustion turbine electric generation facilities. This amount includes $934 million for power island equipment and engineering, procurement and construction costs and $17.8 million for contingency costs. Only actual amounts incurred up to $951.8 million shall be recoverable through rates.

E. DTE Electric Company shall file a list of environmental permits to be obtained, updated as necessary, and an affidavit attesting that the company has obtained all necessary permits as set forth in the order.

F. In DTE Electric Company's integrated resource plan filing on March 29, 2019, the company shall include an additional scenario that evaluates a portfolio consisting of energy efficiency, renewable energy, demand response, storage, and other non-fossil fuel options, ramping up over the years preceding 2029, that could augment the approved natural gas combined cycle plant in 2022, and replace the capacity and energy lost due to the retirement of the Belle River Power Plant.

G. In DTE Electric Company's integrated resource plan filing on March 29, 2019, DTE Electric Company shall provide an updated rate impact analysis related to the approved project, consistent with the discussion in this order.

H. DTE Electric Company and the Commission Staff shall collaborate with the Midcontinent Independent System Operator Inc. and International Transmission Company on reliability planning for coal retirements.

I. The Commission Staff shall evaluate and make recommendations for best practices for requests for proposals, competitive bidding, and risk assessment to be included in the integrated resource plan filing requirements and integrated resource plan guidelines.

J. In the detail specified by the Commission Staff, DTE Electric Company shall annually file, or more frequently if required by the Commission, reports to the Commission regarding the status of any project for which a certificate of necessity has been granted, including an update concerning the cost and schedule of that project pursuant to MCL 460.6s(7).

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so by the filing of a claim of appeal in the Michigan Court of Appeals within 30 days of the issuance of this order, under MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg, Chairman

Norman J. Saari, Commissioner

Rachael A. Eubanks, Commissioner
concurring in a separate opinion

By its action of April 27, 2018.

Kavita Kale, Executive Secretary

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **DTE ELECTRIC COMPANY** for approval of certificates of necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.	)	Case No. U-18419

<u>CONCURRING OPINION OF COMMISSIONER RACHAEL A. EUBANKS</u>

(Submitted April 27, 2018)

This proceeding, which has culminated in granting DTE Electric Company the three Certificates of Necessity that the company applied for, was extraordinarily complex and contentious. This is manifested in the thousands of pages of company and intervenor testimony that formed the evidentiary record, as well as public comment. With so much information available, a number of differing conclusions could be drawn. While it does not change the final outcome, I am making additional observations regarding the application, proceeding, evidence, and process.

As has been discussed numerous times throughout this order, DTE Electric made a clear and compelling case for the need to build a new facility in the near term. The upcoming wave of retirements of Trenton, River Rouge, St. Clair, and Belle River in the 2020s due to concerns related to age, ongoing maintenance expenses, and environmental issues and compliance costs are thoroughly discussed in the majority opinion and my concurrence in that finding will not be repeated here.

The question of whether this plant "represents the most reasonable and prudent means of meeting that power need" is far less clear cut, in my view. DTE Electric has applied for a 1,100 MW natural gas fueled combined cycle electric generation facility. While this proposal may be economically efficient from a construction and siting standpoint, the design introduces a level of risk due to the use of a single-fueled resource that has experienced historically volatile pricing. 5 Tr 232, 913-930. A single generating large-scale resource is also finite, leaving less room for emerging technologies, increased demand response, renewable energy technologies, or energy efficiency measures over its expected 30-year useful life. In short, I am not certain that putting all the eggs in one basket is the best, or only, strategy to follow. To me, DTE Electric did not make a strong showing that it had fairly and thoroughly explored alternative solutions to meet near term electricity demand that could have resulted in less risk for customers. Ultimately, however, no party proved that there was a more reasonable and prudent option to meet this essentially uncontested need for near-term investment in electric generation.

The potential risk this plant poses for customers was also not lost on intervenors who spent incredible time and resources to build their own models and run alternate scenarios without the benefit of having all the details necessary to do so. Because DTE Electric was not fully transparent in its modeling, it is understandable that intervenors were unable to perfectly replicate DTE Electric's set up and therefore did not provide a true "apples-to-apples" comparison. 5 Tr 210-211, 324, 452, 696, and 6 Tr 1570. This in and of itself is important to uncover; modeling applications, whether it's Strategist, PROMOD, or another option, depend on far more inputs than what DTE Electric made available to other parties. Instead of making their process more transparent and using it as an opportunity to gain stakeholder support for its approach, DTE Electric chose to entrench itself in unresponsiveness, denying crucial discovery requests, including the Commission Staff's request for DTE Electric to run additional scenarios. 5 Tr 195-196; October 10, 2017 Ruling Granting Motion to Compel Discovery. This is not an acceptable practice when the integrity of this Commission's process is dependent on stakeholder input and transparency so we as Commissioners can make an informed decision that best represents the public interest. Even with those challenges, I commend the work of the Staff and intervenors whose efforts were invaluable to me as I sorted through their analyses of different paths that demonstrated there is no one answer for filling DTE Electric's proven need. That said, the alternatives presented introduced other significant risks to the analysis given the near term need that I viewed as more significant than DTE Electric's proposal, such as depending on energy waste reduction or demand response to ramp up in an unprecedented time frame and quantity, or utilizing renewable energy technologies that have not been proven in Michigan's unique climate and geography. 6 Tr 1773-1839. Any economic benefits, once adjusted for DTE Electric's modeling assumptions, did not overcome a reasonable range of deviation considering the array of projections that have to be made in any scenario. *Id.*

Yet, in evaluating "other electric resources that could defer, displace, or partially displace the proposed generation facility," I found that there seemed to be gaps in the record that represented options I thought logical to consider. For example, in the DTE Electric IRP Exhibit A-4, multiple-sized gas plants were considered early in the modeling process but were not followed through or thoroughly vetted by the intervenors in the same manner as the "all or nothing" full displacement. As a result, partial displacement options utilizing a smaller plant were underdeveloped in the record. While perhaps somewhat more expensive on a per kilowatt-hour basis at the outset, fully modeling a smaller plant alongside additional renewable energy, energy efficiency programs, load management, and demand response may have been tremendously valuable in understanding ways to mitigate fuel risk for customers, and associated cost tradeoffs under various assumptions and scenarios. Unfortunately, the deficiency of the record in this area left me unable to realistically consider this option. As Staff witness Simpson pointed out in her direct testimony, DTE Electric did not demonstrate or explain that it crafted its model to select resources on an equitable basis and she had additional concerns with the modeled sizes of generic resources. 5 Tr 209-216.

Other alternatives, other than plant size, also did not seem to be fully evaluated by DTE Electric. Staff and witnesses in their testimony argued that DTE Electric did not assess and model demand response (DR) to its full potential and should have modeled scenarios with higher DR assumptions. 5 Tr 261, 696, 329-330, 424. Similarly, the Staff and intervenors argued DTE Electric should have used 2% energy efficiency in all of its models, as opposed to the 1.5% used in the majority of DTE Electric's model assumptions. 5 Tr 234, 209, 696, 329-330, 367. With respect to renewable energy, several intervening parties were concerned that DTE Electric's modeling of wind and solar were biased against renewable resources, specifically that the costs were overinflated and the blocks were too large. 5 Tr 456, 469, 471, 474. As a result, it was nearly impossible for these options to be chosen in any modeling scenario. 5 Tr 478. DTE Electric's alternatives analysis included a 950 MW combustion turbine in the model, making the alternatives unlikely to be chosen as they were crowded out. 5 Tr 444-499, 212-213. Further, gas price uncertainty once again came into play in modeling as intervenors disputed DTE Electric's use of a short-term Henry Hub gas price forecast from 2018-2022 which transitions to a long-term forecast from PACE Global. 5 Tr 915, 949. Such flaws cast doubt onto DTE Electric's modeling process, but in my view, the alternatives modeled by the intervenors also had flaws (6 Tr 1772-1839), albeit somewhat due to DTE Electric's lack of full transparency.

This Commission, including this Commissioner, carefully follows the letter of the law, and there is no question the provisions for the IRP in Section 6s governed this proceeding and we applied those provisions faithfully in our decision making. The provisions in that section of the law date back to 2008 and apply to this proceeding. They were updated in 2016, when the Legislature and Governor enacted an overhaul of Michigan's energy laws, which includes a comprehensive framework for how the Commission should shape Michigan's energy future, including reintroducing a standalone IRP (outside of a CON) in Section 6t that allows for a more holistic and inclusive process for how major resource decisions will be made. I am grateful for those changes because I believe it will improve our process and will better incorporate a variety of perspectives instead of starting from a specific utility proposal. In this case, intervenors argued that certain modeling runs or sensitivities that the Commission has laid out in its Section 6t IRP filing requirements should have been included because they would have produced a different result. While I disagree that the Commission should have evaluated DTE Electric's proposal through the lens of the Section 6t IRP, it is a fair question to consider how critical pieces of the legislation, once having had the ability to be fully implemented, would have impacted the results of this proceeding.

A number of other factors, including the impact of the Tax Cuts and Jobs Act (TCJA), were raised by intervenors – both in terms of the upfront cost of the plant and the TCJA's impact on the costs of the alternatives – yet were not quantified in a meaningful way. It is a given that even in an expedited 270 day proceeding for a CON, there will be changes to the project cost that are outside of the utility's control. To DTE Electric's credit, the company made attempts to mitigate potential cost fluctuations. We cannot restart the process for every possible change to those costs. However, had the record demonstrated a sense of the magnitude of the changes that occurred as a result of the TCJA, and that magnitude was meaningful, it could have warranted a revisiting of the upfront cost and alternatives analysis.

Another example of a concern I saw in this case was the bidding process that DTE Electric undertook when it sought alternatives to building itself. I see merit in the intervenors' arguments that limiting the term of the PPA to seven years to align with DTE Electric's capacity need limited the potential for a robust response to the solicitation. 5 Tr 200-201, 607-623. In addition, those parameters did not provide an appropriate comparison to the DTE Electric build option. Yet no entity utilized a provision in the law where they could approach the Commission directly with a proposal. In the absence of such a proposal I must assume that such alternatives are simply not viable for this particular need.

In the end, the need is too near term and the stakes for customers are too high for me to consider any alternate path contained in this record to be a more reasonable and prudent option than the one presented by DTE Electric. DTE Electric is taking on an enormous responsibility to the public in building this plant and I want to assure the public that the Commission and its Staff will be monitoring this build extremely closely. While the process of determining what to build will be different going forward, I ultimately see this plant as a part of Michigan's transition to an energy future that is adaptable, reliable, affordable, and protective of our environment.

MICHIGAN PUBLIC SERVICE COMMISSION

Rachael Eubanks

Commissioner, Rachael A. Eubanks

P R O O F   O F   S E R V I C E

STATE OF MICHIGAN)

Case No. U-18419

County of Ingham)

Lisa Felice being duly sworn, deposes and says that on April 27, 2018 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Lisa Felice

Lisa Felice

Subscribed and sworn to before me
this 27th day of April 2018

Steven J. Cook

Steven J. Cook
Notary Public, Ingham County, Michigan
As acting in Eaton County
My Commission Expires: April 30, 2018

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ORIGINAL

Ex. AA-S-3

TDO
SNK

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE GAS TURBINE GENERATION FACILITY ("CCGT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("CULLEY 3 COMPLIANCE PROJECT"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CULLEY 3 COMPLIANCE PROJECTS THROUGH VECTREN SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM; (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE REVENUE REQUIREMENT FOR COSTS, INCLUDING CAPITAL, OPERATING, MAINTENANCE, DEPRECIATION, TAX AND FINANCING COSTS ON THE CULLEY 3 COMPLIANCE PROJECT WITH CARRYING COSTS AND (B) POST-IN-SERVICE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CCGT AND CULLEY 3 COMPLIANCE PROJECT UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) ONGOING REVIEW OF THE CCGT; (7) AUTHORITY TO IMPLEMENT A PERIODIC RATE ADJUSTMENT MECHANISM FOR RECOVERY OF COSTS DEFERRED IN ACCORDANCE WITH THE ORDER IN CAUSE NO. 44446; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CCGT AND CULLEY 3 COMPLIANCE PROJECT ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 *ET SEQ*, 8-1-8.5-1 *ET SEQ.*, AND 8-1-8.8 -1 *ET SEQ.*	)	CAUSE NO. 45052 APPROVED: APR 24 2019

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Senior Administrative Law Judge

On February 20, 2018, Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") filed its verified petition in this Cause seeking, among other relief, certificates of public convenience and necessity for a new duct-fired F-class 2x1 combined cycle gas turbine ("CCGT") providing 700 MW of baseload and 150 MW of peaking capacity pursuant to Ind. Code ch. 8-1-8.5 and for certain environmental projects at its Culley Unit 3 generating station pursuant to Ind. Code ch. 8-1-8.4. Petitions to intervene were filed by the Vectren Industrial Group; Valley Watch, Inc., the Citizens Action Coalition of Indiana, Inc., and the Sierra Club ("Joint Intervenors"); the Indiana Coal Council, Inc. ("ICC"), Sunrise Coal, and Alliance Coal, LLC (the "Coal Parties"); SABIC Innovative Plastics Mt. Vernon, LLC; St. Joseph Energy Center, LLP; St. Joseph Phase II LLC; and Evansville Western Railway. All of these petitions to intervene were subsequently granted. A public field hearing was held in Evansville on July 11, 2018, at which time members of the public presented testimony. The Indiana Utility Regulatory Commission ("Commission") held an evidentiary hearing at 9:30 a.m. on October 9, 2018, in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana.

Based upon the applicable law and the evidence presented, the Commission finds:

1. **Notice and Jurisdiction.** Notice of the hearings in this Cause was given and published as required by law. Vectren South is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.5-1, an "energy utility" as defined in Ind. Code § 8-1-8.4-3, and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. Vectren South is subject to the jurisdiction of this Commission in the manner and to the extent provided by Indiana law. Pursuant to Ind. Code chs. 8-1-8.5 and 8-1-8.4, Vectren South may seek Commission approval of Certificates of Public Convenience and Necessity. Accordingly, the Commission has jurisdiction over Vectren South and the subject matter of this proceeding.

2. **Vectren South's Characteristics.** Vectren South is an operating public utility incorporated under the laws of the State of Indiana, with its principal office and place of business in the City of Evansville. Vectren South provides electric and gas utility service to the public in Indiana and is subject to the regulation by this Commission in the manner and to the extent provided by the laws of the State of Indiana. This proceeding pertains to Vectren South's electric utility business. Vectren South renders retail electric utility service to approximately 145,000 customers in seven counties in southwestern Indiana, and owns, operates, manages and controls electric generating, transmission and distribution plant, property and equipment and related facilities which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light and power for residential, commercial, industrial and municipal uses. Vectren South furnishes such electric utility service to retail customers located in Vanderburgh, Posey, Gibson, Pike, Warrick, Dubois and Spencer Counties, with a major portion of such customers residing in and around the City of Evansville, Indiana. Vectren South owns and operates 1,248 megawatts ("MW") of total net generating capacity. This generation capacity is primarily derived from the following five coal-fired baseload units providing a total of approximately 1,000 MW: A.B. Brown 1 (245 MW), A.B. Brown 2 (245 MW), F.B. Culley 2 (90 MW), F.B. Culley 3 (270 MW) and Warrick Unit 4 (150 MW[1]). Vectren South procures 100% of its coal supply from mines located in Indiana.

[1] Represents Vectren South's ½ interest in Warrick Unit 4, a 300 MW unit.

Vectren South's operations are subject to federal, state and local rules promulgated and/or implemented by, among others, the federal Environmental Protection Agency ("EPA"), the Indiana Department of Environmental Management ("IDEM") and by the Environmental Rules Board of the State of Indiana. Such rules establish environmental compliance standards that govern emissions and discharges from Vectren South's electric generating units.

3. Overview of the Evidence.

A. Condition of Current Fleet.

i. Vectren South. The main drivers behind Vectren South's proposal are the age and operating characteristics of Vectren South's existing baseload capacity and the upcoming deadlines for significant capital investments to address environmental regulations. Mr. Wayne D. Games, Vice President of Power Supply at Vectren South, testified regarding the condition of Vectren South's current generation fleet and the challenges facing the fleet. He testified Vectren South's fleet consists of five coal-fired baseload units totaling 1,000 MW. Mr. Games further testified that growth of renewable energy sources and low natural gas prices have negatively affected MISO's dispatch of Vectren South's coal-fired units. Instead of running continuously, Vectren South's units are now cycled up and down throughout the day, or are shut down altogether, decreasing unit efficiency and increasing wear and tear on the units. Mr. Games testified that because the units were not designed to cycle in this manner, the units cannot effectively compete with gas units in particular, which have far better operating flexibility. Continued market reforms are exacerbating this issue and jeopardizing unit availability and reliability.

Mr. Games also explained that the individual units face additional operating challenges. In particular, the A.B. Brown Units rely on scrubbers that utilize a technology that has been abandoned by the industry because of its high variable costs and the vapor it emits which causes corrosion of the unit structure. The scrubbers are already past their expected 30 year design life and present a significant risk to reliability and maintenance costs. He explained that Culley Unit 2 is Vectren South's oldest and smallest unit and that it has the worst heat rate of any coal unit in the state. Finally, he explained the unique circumstances related to the joint operation of the Warrick Unit which creates uncertainty as to the duration of its operation.

Ms. Angila Retherford, Vice President of Environmental Affairs and Corporate Sustainability, testified regarding two new major federal regulatory initiatives – Effluent Limitations Guidelines ("ELG") and Coal Combustion Residuals ("CCR") - impacting Vectren South's coal-generating units. Absent substantial investment at all of Vectren South's coal plants, they must cease operations by December 31, 2023. Ms. Retherford described Vectren South's environmental compliance strategy for the A.B. Brown and Culley units and testified future compliance costs were modeled in Vectren South's 2016 Integrated Resource Plan ("IRP") under the business as usual scenario. Ms. Retherford testified these rules and other existing federal regulatory requirements will require Vectren South to make significant further investment at the A.B. Brown and Culley generating facilities to continue their operation.

ii. Non-Utility Parties.

(1) OUCC. OUCC witnesses Lauren M. Aguilar – Utility Analyst, Anthony A. Alvarez – Utility Analyst and Peter M. Boerger – Senior Utility Analyst testified regarding Vectren South's request for a CPCN to construct the CCGT. These OUCC witnesses testified Vectren South's decision to construct the CCGT is premature because Vectren South has not explored all practical alternatives to extend the life of the A.B. Brown units. OUCC Witness Aguilar ultimately recommended that the decision to build the CCGT be delayed until the end of the 2019 IRP process, in order to allow Vectren South the opportunity to evaluate additional alternatives. The OUCC offered no alternative resource proposal, but argued for a "blended approach" with the possible continued use of existing assets, and suggested that the necessary expenditures to continue use of these assets could be viewed as buying an "option on the future." The OUCC witnesses asserted that deferring any decision until the conclusion of the 2019 IRP process would still allow sufficient time to take action without affecting reliability.

(2) Coal Parties. The Coal Parties' witnesses generally testified that Vectren South should wait to transition its baseload generation from coal to natural gas because the environmental regulations driving the transition, the ELG and CCR rules, are in flux and not yet final. Specifically, the Coal Parties' witnesses testified that recent and anticipated EPA reconsiderations of the ELG and CCR regulations, as well as the potential stay or replacement of the Clean Power Plan ("CPP"), create the potential scenario where Vectren South could operate the A.B. Brown and Culley units beyond 2023 without the need to make material investments in compliance measures. Coal Parties witness Michael J. Nasi – Partner with the law firm of Jackson Walker L.L.P. – further testified that Vectren South's decision to retire its coal plants is premature. He recommended that the decision be delayed until the environmental regulations driving the decision are better understood. With respect to the A.B. Brown units, the Coal Parties suggested that Vectren should investigate an alternative scrubber technology marketed by a Chinese firm to replace the existing dual alkali scrubbers. This technology which uses ammonia creates material that can be sold as fertilizer with revenues used to offset variable operating costs of the scrubber.

iii. Vectren South Rebuttal. Ms. Retherford, who is also a licensed attorney, testified regarding the risks associated with continuing to operate Vectren South's coal-fired fleet and delaying the decision to construct the proposed CCGT. Ms. Retherford testified that recent legal developments related to the CCR rule have made it impossible for Vectren South to continue operating its coal-fired fleet beyond 2023 without significant capital investment. She testified that the current water discharge permits require, and the groundwater monitoring results at the A.B. Brown and Culley ash ponds confirm, that Vectren South must cease discharging coal ash by December 31, 2023, pursuant to the ELG and CCR rules. She also testified that *Utility Solid Waste Activities Group v. Environmental Protection Agency*, 901 F.3d 414 (D.C. Cir. 2018), 2018 U.S. App. LEXIS 23547, confirms that the CCR Rule is final, including the final compliance deadlines at issue in this proceeding. Ms. Retherford testified that pond retirement delay is not an option, and therefore Vectren South must either make investments to comply with the CCR rule or retire the plants before 2024.

In response to the Coal Parties' position that the current administration could alleviate environmental carbon regulations applicable to the coal units, Ms. Retherford testified that the Administration's proposed replacement for CPP does not alleviate the problems. On August 31, 2018, the EPA published its proposed Affordable Clean Energy ("ACE") rule in lieu of CPP. She explained that ACE would increase uncertainty and could actually increase the cost of compliance. For units with high heat rates – such as A.B. Brown – ACE would cause significant future compliance costs.

Vectren South also presented the testimony of Richard McMahon from Edison Electric Institute ("EEI") regarding the growing importance of Environmental, Sustainability and Governance ("ESG") reporting and metrics to the financial community, and the focus of all public electric utilities on being responsive to these topics and establishing explicit carbon reduction targets as part of their public disclosures. Mr. McMahon described the coordinated electric industry response to the demands for ESG reporting, and provided specific examples of lenders and large institutional investors who are putting pressure on companies to transition from dependence on coal units. He explained that Vectren South's 60% carbon emission reduction was in line with similar targets publicly disclosed by its electric utility peers. He also presented information regarding the industry transition from reliance on coal to use of gas as part of the ability to reduce carbon emissions.

As to the potential for alternative scrubbers, Vectren South witness Paul Farber – Principal of P. Farber & Associates, LLC – testified regarding the shortcomings of the technologies presented by Sunrise Coal witness Dombrowski and OUCC witness Aguilar and explained why, from an operational and financial perspective, it would not be prudent for Vectren South to adopt those technologies. With respect to the ammonia based scrubber technology presented by witness Dombrowski, Mr. Farber testified the technology has very limited deployment in the United States and would present a number of operational challenges if installed at baseload coal-fired units like A.B. Brown. These uncertainties and risks posed by adoption of this technology include its cost, its impact on operation of the units (including that it might cause Vectren South to be out of compliance with regulations for other constituents such as mercury and particulate matter absent further types of investments), the unknown ability to sell fertilizer output, and the complications associated with dealing with vendors with no domestic history. He discussed in depth the substantial operational burden and health and Homeland Security risk associated with handling the large amount of ammonia required by such a scrubber. Mr. Farber concluded that the Coal Parties had failed to provide any evidence that the capital costs of this scrubber technology would be any less than the scrubber modeled in Vectren South's 2017 IRP Update. In rebuttal testimony, Jon K. Luttrell, Senior Vice President, Utility Operations and President of Vectren Utility Holdings, Inc., also discussed the cyber security complications and risks posed by adoption of Chinese scrubber technology.

Mr. Farber also responded to OUCC witness Aguilar's criticism that Vectren South "only" evaluated wet limestone and her presentation of potential costs for other technologies. Mr. Farber testified that dry scrubbing is not an applicable technology at A.B. Brown for technical and economic reasons, and therefore it was logical for Vectren South to evaluate wet limestone technology at A.B. Brown. He also testified the cost estimates presented by Ms. Aguilar are not comparable cost estimates to replace the existing scrubbers at A.B. Brown Units 1 and 2.

Mr. Games testified on rebuttal that there simply is no time to delay a decision and await the outcome of another IRP. The Vectren South coal units must be retired or retrofitted by December 31, 2023. Given that there has been nothing to suggest more delay would change the overall economics that the F-class 2x1 CCGT is part of the lowest cost solution under every scenario, there is no reason to believe that modeling in the next IRP would change that result. Mr. Games provided an exhibit setting forth a timeline showing that a delay to allow the next IRP to proceed would leave Vectren South with essentially no baseload capacity for almost three years. During that entire period, Vectren

South customers would be completely exposed to the market for capacity and energy. Per the redirect examination of Justin M. Joiner, Director of Regulatory Policy and MISO Affairs for Vectren Utility Holdsings, Inc. ("VUHI"), this would be during the period when MISO is projecting its largest capacity shortfall for Zone 6 (Indiana). The Commission's Director's Report states "[a]n appropriate planning aspiration is to maintain flexibility while also waiting as long as reasonably possible to commit to a resource." Mr. Games testified on cross-examination that Vectren South has waited as long as reasonably possible.

B. Modeling and Results. Only two parties presented modeling evidence and results. Vectren South presented the modeling from the 2017 IRP Update and the 2016 IRP. Sunrise Coal Witness Philip Hayet presented alternative modeling whereby Vectren South's Preferred Portfolio was delayed by seven years in order to allow existing coal units to continue to operate beyond 2023. Other parties offered criticism of Vectren South's modeling but presented no alternative modeling.

i. 2016 IRP. Vectren South's case was filed in the context of a proposed new rule to govern the IRP process. While our new rule was not effective during the 2016 IRPs, all participating electric utilities complied. This new process is significantly more transparent. It includes the participation of stakeholders, the convening of public meetings, and the submission of and response to comments. Mr. Matt Rice, Director – Research and Energy Technologies, testified regarding Vectren South's IRP process and the results of that process. Mr. Rice described Vectren's approach to its 2016 IRP process and testified Vectren South engaged several industry experts, including Burns & McDonnell and Pace Global, to conduct technical modeling. Mr. Rice testified Vectren South worked with these experts and IRP stakeholders to conduct scenario analysis to evaluate 15 portfolios, each representing a different mix of supply and demand side resources to meet customer load over a 20-year time horizon. He further testified Vectren South worked with Pace Global to conduct a risk analysis and evaluate the 15 portfolios using a balanced scorecard approach. From this analysis, Vectren South identified the "preferred portfolio" which consisted of replacing all existing coal fired generation other than Culley Unit 3 as well as gas peaking units Northeast 1 and 2 and Broadway 1 by 2024 with an F-class .05 Fired CCGT. Mr. Rice testified Vectren South incorporated stakeholder input throughout the process and described the steps Vectren South took to engage stakeholders both before and during the process. This engagement included having stakeholders develop two portfolios which were then modeled and included in the risk analysis.

Mr. Matthew Lind – Associate Project Manager, Burns & McDonnell – described the modeling Burns & McDonnell conducted in the 2016 IRP on behalf of Vectren South to evaluate its resource needs over the next 20 years. He testified the results of Burns & McDonnell's modeling identified a low-cost portfolio that ceased coal operations at Vectren South's coal fired facilities (A.B. Brown Units 1 and 2, F.B. Culley Units 2 and 3, and Warrick Unit 4) and replaced this capacity and energy with the combined cycle facility proposed here along with a simple cycle facility. Mr. Gary Vicinus – Managing Director for Utilities at Pace Global – described Pace Global's role in identifying and defining the objectives, metrics and risks in order to select the preferred portfolio among the many options. He testified Pace Global used a balanced scorecard approach to apply a risk analysis to a selection of portfolios ultimately to recommend a preferred portfolio. Mr. Vicinus further testified regarding revisions Pace Global made to its risk analysis and explained that, even with these revisions, the risk analysis indicated the preferred portfolio was the best approach.

Mr. Rice described the preferred portfolio and explained why it ranked the best on the balanced scorecard. He testified it performed the best because the portfolio is diversified as it contemplates keeping FB Culley 3 (a coal unit) and existing wind contracts, building a CCGT and introducing solar and continuing to offer energy efficiency. He further testified it is among the lower cost portfolios (within 4% of the predominantly gas lowest cost portfolio) and ultimately performed best overall when viewed across multiple measures on the balanced scorecard. Because the all-gas portfolio represented the lowest cost portfolio, it is the retention of Culley Unit 3 and the accelerated addition of the 50 MW solar project that increases the costs of the Preferred Portfolio over the lowest cost all-gas portfolio. Retention of coal and the addition of solar are essential to diversity.

ii. 2017 IRP Update. Mr. Lind testified Vectren South requested Burns & McDonnell to update the 2016 IRP modeling and the re-evaluated low-cost portfolio was consistent with the low-cost portfolio identified in the 2016 IRP. He explained that several modeling inputs were updated, including the capital cost for solar resources, variable production costs and revenue requirements for existing units, an assumed operation of Warrick Unit 4 through 2023, and updated cost assumptions for capacity, energy, natural gas, coal, and energy efficiency.

OUCC witness Peter Boerger testified regarding Vectren South's 2017 IRP Update economic modeling. Mr. Boerger testified that Vectren South's 2017 IRP Update did not adequately consider viable options for serving its customers—including making use of existing resources and adequately considering the addition of a smaller CCGT unit rather than the 2x1 unit being proposed. Mr. Boerger also testified Vectren South's modeling of the proposed CCGT understated its capital cost by $200 million, an error which disadvantaged other options in Vectren South's modeling. Mr. Boerger ultimately recommended Vectren South reevaluate its future needs and model additional alternatives.

CAC witness Tyler Comings – Senior Researcher at Applied Economics Clinic – testified on behalf of the Joint Intervenors. Mr. Comings criticized Vectren South's modeling, testifying it was too convoluted to yield a sufficiently transparent or credible result. He testified Vectren South used too many models in the selection of the preferred portfolio and that the use of many models created ample opportunity for flawed and/or inconsistent input assumptions and other settings that could create bias in favor of the preferred plan. Mr. Comings ultimately recommended Vectren South's petition be denied because, in his view, Vectren South did not provide sufficient justification for its choice to build the CCGT and continue the operation of Culley 3.

Indiana Coal Council witness Emily Medine – Principal in the consulting firm of Energy Venture Analysis, Inc. – also testified regarding Vectren South's modeling. Witness Medine testified Vectren South should have fully updated its 2016 IRP analysis, including its scenario analysis, in order to confirm its preferred resource portfolio. She further testified that such an update should include a broader analysis (including sensitivity analyses) of the relevant assumptions and factors as of a time as close to Vectren South filing its Petition as possible. Ms. Medine attributed the decision to build a CCGT to financial motivations and also opined that approval of the CCGT might be a condition to closing the Vectren South merger transaction.[2] Ms. Medine recommended that Vectren South's Petition be rejected because Vectren South has failed to show that proceeding with building the CCGT at this time is prudent, less risky, and a better decision for both customers and the environment.

[2] While this case was pending, it was announced publicly that Vectren South's holding company was the subject of an acquisition at the holding company level, which was the subject of Cause No. 45109.

Mr. Lind responded to Mr. Boerger's testimony about an alleged $200 million "error." He explained that approximately $67 million of the alleged error identified by Mr. Boerger was due to Mr. Boerger's mistaken assumption about whether modeled option costs are stated in 2017 dollars or nominal dollars in the year of incurrence. The remainder is due to Mr. Boerger's efforts to compare apples and oranges. As Mr. Lind explained, the modeling was done prior to the more refined cost estimates for the CCGT that were developed for this case. Rather than based on a design level accuracy of plus/minus 50%, the CCGT design has been refined to a plus/minus 10%. All of the other portfolios were still at plus/minus 50%. As Mr. Lind explained, to compare the other less refined portfolios to the more refined CCGT would require some additional risk factor for the other portfolios. But even if one includes the updated cost estimate, Mr. Lind testified that it doesn't change that the lowest cost portfolios still include the CCGT. Mr. Lind prepared additional modeling involving coal-to-gas conversion (which we will describe later) and which did include the more refined CCGT cost estimate. While this additional modeling used the more precise CCGT cost and therefore impacted every portfolio that included the CCGT by increasing the overall net present value ("NPV") by $54 million, the portfolios that included the CCGT were still the lowest cost portfolios compared to portfolios that did not include the CCGT. Regarding the use of the models, witnesses Lind and Vicinus confirmed that the process and modeling for Vectren South's IRP and risk analysis were consistent with the resource planning approach Pace and Burns & McDonnell have used for numerous other utilities.

(iii) Size of the Proposed CCGT. Joint Intervenors' witness Tyler Comings testified regarding the size of the proposed CCGT. Witness Comings testified that Vectren South has not provided a sufficient justification to build a CCGT of the size included in its proposal. Witness Comings also criticized Vectren South's Request for Proposals ("RFP") (which we will describe in greater detail later) which sought resources between 600 and 800 MW, because he believed Vectren South could have considered combinations of small resources that added up to 600 MW. He further testified that considering smaller options would limit the market risk exposure for ratepayers, as well as permit a combination of bids to make up a least cost alternative. Mr. Comings testified that in order to reduce ratepayers' risk, Vectren South should explore cost effective alternatives that do not require intensive capitalization, but still provide benefits to ratepayers.

OUCC witness Anthony Alvarez also testified regarding the size Vectren South is proposing for the CCGT. Mr. Alvarez testified that Vectren South currently has excess supply, and there is no resource shortfall or inadequacy that supports Vectren's proposed 850 MW CCGT. He also questioned the load forecast used in the IRP and testified Vectren South has excess supply after serving its peak load and therefore has excess capacity to offer into the market and serve new customers.

Industrial Group witness Michael Gorman also testified regarding the size of Vectren South's proposed CCGT. Mr. Gorman testified Vectren South's proposal to build an 850 MW CCGT will result in excess capacity and have a compound impact on Vectren South's cost of service because the plan increases the costs of new generation resources and results in unrecovered stranded costs from the retired resources. Mr. Gorman recommended the Commission implement mitigation measures to reduce the cost burden on customers related to stranded costs and the cost of the new CCGT. He also recommended the Commission modify the off-system sales margin treatment so that 100% of future wholesale revenues be provided to customers to offset the cost of the proposed resource plan.

Vectren South witness Carl Chapman testified on rebuttal regarding Vectren South's decision to construct an 850 MW CCGT. Mr. Chapman explained the CCGT is essentially two units -- a 700 MW baseload unit to replace 730 MWs of retiring coal unit capacity and 150 MWs of duct fired peaking capacity to replace older peaking units and provide available low cost capacity for growth and wholesale sales opportunity. The additional peaking capacity is provided by the decision to duct-fire the CCGT. The incremental cost of duct-firing the CCGT is $15 million, and that decision must be made at the time the CCGT is constructed (i.e., it cannot be added at a later time.) Mr. Chapman testified that if only the unfired 700 MW baseload CCGT is built, then by 2025, Vectren South has a projected surplus above MISO's Planning Reserve Margin ("PRM") (which fluctuates) of only 51 MW. He further testified that by 2030, the surplus is only 5 MWs and by 2031 Vectren South will fail to meet its PRM. He testified that by 2036, Vectren South will be short 39 MWs, and all of this assumes Vectren South will not add significant new load. Mr. Chapman testified that with its low capital cost, firing makes sense from a customer perspective. For an incremental cost of 2%, the firing provides a 21% increase in capacity. Nevertheless, if the Commission approves the baseload 700 MW CCGT without firing, Vectren South will proceed to construct the unfired CCGT to replace its baseload coal units. He stated that Vectren South would also consider investing the incremental $15 million to duct-fire the unit and be at risk to recoup its investment via retention of the wholesale revenue produced by that peaking capacity.

Mr. Chapman also testified regarding Industrial Group witness Gorman's recommendation that Vectren South pass off-system sales margins on to retail customers. Mr. Chapman testified that Vectren South has decided to commit to provide 100% of wholesale sales revenue from the CCGT (baseload and peaking) to customers. Mr. Chapman explained that once the CCGT is placed in rate base, the benefits from the wholesale revenue produced by the unit will go to reduce customer costs. Mr. Chapman testified that providing 100% of wholesale revenue to customers further improves the NPV of the CCGT, will provide a larger offset to customer costs in general, and adds even more support to the $15 million incremental investment to duct fire the unit.

C. **<u>Coal Parties' Modeling</u>.** Indiana Coal Council, Inc. witness Philip Hayet – Vice President of J. Kennedy and Associates, Inc. – testified regarding Vectren South's 2016 IRP modeling and the 2017 IRP Update. Mr. Hayet testified that Vectren South's modeling analyses were flawed due to errors, inconsistencies, and a lack of consideration of important factors. Mr. Hayet performed his own analysis and testified that using the same model with certain corrections, including a deferral of a decision to add a CCGT, produced a slightly lower cost result on a NPV basis. He predicated his modeling on the assumption that the A.B. Brown 2 scrubber will continue to operate reliably through 2030. He ultimately recommended that Vectren South defer its decision to construct the CCGT.

On rebuttal, Vectren South witness Matthew Lind testified regarding Indiana Coal Council witness Hayet's alternative modeling. Mr. Lind testified that when Mr. Hayet's modeling is corrected for obvious errors, it reaches the same preferred portfolio conclusion as Vectren South's modeling. Mr. Lind provided corrections to Mr. Hayet's modeling in the form of an updated Strategist model and spreadsheets documenting the corrections. Mr. Lind outlined each of the errors he identified in Mr. Hayet's modeling and the impact of the individual errors on his analysis. The first of several errors he identified was that Mr. Hayet failed to include cost escalation during the seven years of delay that he was urging and that correcting this error alone would change Mr. Hayet's overall conclusion that delay would be less costly. Mr. Lind also testified regarding the cumulative effect of addressing all of the errors. As part of this analysis, Mr. Lind testified that he included the increased cost of the CCGT to reflect the more recent cost estimates based on a plus or minus 10% confidence level. He testified that when correcting Mr. Hayet's modeling for all of these errors and inconsistencies, the NPV favors Vectren South's preferred portfolio, even under Mr. Hayet's no carbon regulation scenario. Witness Hayet corrected his testimony after Mr. Lind filed his rebuttal to add the escalation during the period of delay he was urging, and this correction changed his original conclusion that delay was less expensive. Mr. Hayet did not address the other modeling issues raised by Mr. Lind.

Mr. Games' rebuttal testimony also addressed witness Hayet's assumption that the A.B. Brown 2 unit and scrubber could be operated without added cost and reliability risk through 2030. Apart from the reliability issues created by the frequent cycling of the unit, he explained the structural damage resulting from the corrosive environment created by the unique characteristics of these scrubbers, and based on his direct experience with this equipment, Mr. Games concluded that he could not agree that it would be prudent to continue to operate the A.B. Brown 2 scrubber for another 12 years beyond 2018.

D. Renewables and All-Source RFP. Joint Intervenor witness Tyler Comings criticized the costs assumed in Vectren South's modeling for most renewable energy sources. Mr. Comings testified that Vectren South's forecast of the capital costs of future wind resources is higher than he would have recommended for the type of planning analysis and its forecast of the fixed O&M costs are lower. Mr. Comings recommended the use of the National Renewable Energy Laboratory's Annual Technology Baseline ("ATB") to develop the forecasts. With respect to future solar resources, Mr. Comings testified Vectren South's forecasts are too high for both the capital and fixed O&M costs. Mr. Comings recommended the reliance on the ATB to develop wind and solar price forecasts. For utility-scale PV, he testified that the ATB midpoint projection would be appropriate. As part of his discussion of renewable costs, he noted that Northern Indiana Public Service Company ("NIPSCO") had recently conducted an RFP and obtained solar and wind bids. Mr. Comings testified that Vectren South's overestimation of renewable costs compared to the ATB data biased the modeling results against renewable resources in favor of non-renewable resources, such as natural gas.

On rebuttal, Mr. Lind responded to Mr. Comings' testimony related to the cost of renewables included in Vectren South's modeling. With respect to wind resources, Mr. Lind noted that prior to revising his testimony, Mr. Comings' originally filed testimony included an inaccurate and inappropriate comparison of assumed capital cost for wind resources between Vectren South and ATB because Mr. Comings failed to account for the declining cost curve over time utilized by Vectren South. Mr. Lind testified that when Mr. Comings updated his testimony to reflect this decline, he recognized that Vectren South's wind costs are only "slightly higher" than what Mr. Comings recommends. Mr. Lind further testified that even with this correction, Mr. Comings' comparison to the ATB figures is incorrect because the ATB figure excludes a 2.1% construction finance factor and is thus understated. Mr. Lind testified that when the 2.1% construction finance factor is included, the ATB capital cost will exceed Vectren South's modeled capital cost for wind over more than half of the planning period. Mr. Lind pointed out that Vectren South assumed a higher capacity factor than the ATB survey and also assumed lower O&M costs compared to the ATB survey, and as a result, it is likely that the wind prices recommended by Mr. Comings are actually higher than those modeled by Vectren South.

With respect to Mr. Comings' criticisms of Vectren South's solar costs, Mr. Lind testified Mr. Comings again failed to account for the declining cost curve over time in the original version of his testimony. Mr. Lind further testified that while Mr. Comings did update his comparison to reflect the decline, he did not update it to include the 2.1% construction finance factor in the ATB comparison. Moreover, Mr. Lind explained that the national survey costs relied upon by Mr. Comings were presented on a direct current (DC) basis, whereas the 2017 IRP Update stated cost in terms of alternating current (AC), thus requiring that Comings' costs be converted to AC to allow for a valid comparison to be made. When correcting for these additional errors, Mr. Lind testified the solar costs used by Mr. Comings and Vectren South are nearly consistent over the last half of the study period and fairly similar from 2024 onward, which is the point at which capacity is needed.

Mr. Lind also testified regarding the impact of network upgrades and congestion costs on a portfolio that would rely more heavily on renewables. Mr. Lind testified that a portfolio which would rely heavily on renewables to supply power to Vectren South's customers is more likely to source some or all of these resources remote to Vectren South's service territory given the acreage required for such projects, the grid issues that can be encountered, and the enhanced production that can be obtained in certain locations (e.g., northern Indiana). Mr. Lind explained that when significant amounts of power are sourced from off-system resources, congestion costs to Vectren South's customers increase substantially. Because such costs were not part of the 2017 IRP Update assumptions, Mr. Lind concluded that any small differences between the solar costs presented by Mr. Comings and those modeled by Vectren South would be more than offset by the congestion costs associated with greater reliance on such resources. Finally, Mr. Lind noted that even assuming lower renewable costs could be achieved, such resources would likely displace Culley Unit 3's 270 MWs of capacity because that could be done incrementally to reduce the effects of network upgrades and congestion, whereas the CCGT would remain the optimal low cost choice to replace the remaining 730 MWs of retiring coal capacity in 2023. Further, wind and solar are intermittent sources of power; given that Culley Unit 3 would be Vectren South's only baseload capacity under its preferred portfolio, dispatchable baseload generation from a CCGT provides greater flexibility to respond to intermittent resources.

E. **<u>Capacity Price Forecasts</u>.** Mr. Comings testified regarding Vectren South's ability to purchase future needed capacity from the MISO market. Mr. Comings testified that Vectren South overestimated future capacity prices in MISO in its modeling, and in reality, the MISO market has had an oversupply of resources and tempered demand, leading to low capacity prices. He testified Vectren South's assumption of higher capacity prices is critical, because it makes the economics of building a new resource more attractive. He concluded that Vectren South was placing risk on its customers if the price of capacity is lower. To reach his conclusion, he relied on the MISO auction clearing results for Zone 6 (Indiana) for the past five years. Indiana Coal Council witness Hayet had a similar criticism of Vectren South's modeled capacity prices. He agreed that the cost of new entry ("CONE") served as the upper end of future capacity prices but that, also based on MISO historic auction clearing prices, it was inappropriate for future assumed capacity prices to approximate CONE. Instead, witness Hayet proposed to use 75% of CONE.

On rebuttal, Vectren South witness Joiner responded to Mr. Comings' testimony related to Vectren South's alleged overestimation of MISO capacity prices. Mr. Joiner testified he disagreed with Mr. Comings' contention that Vectren South should assume it will be able to purchase capacity and energy from the MISO market at low prices based upon recent market conditions. Mr. Joiner explained that the MISO market has been volatile in recent years and is experiencing shrinking capacity, and such factors have prompted MISO to evaluate changes to its market structure. Mr. Joiner testified that MISO's recent and pending market reform initiatives, including MISO's Resource Availability and Need ("RAN"), are aimed at increasing capacity and energy prices to incentivize new generation development and are thus leading to higher prices as capacity tightens. As such, Mr. Joiner testified that while MISO's historical capacity and energy prices are indicators of recent trends, contrary to Mr. Comings' MISO auction clearing price testimony, they are not good indicators of expected, long-term future pricing. Moreover, the reported potential for a capacity shortfall by 2024 shows the risk of increased market prices.

F. Refueling Options. OUCC witness Boerger recommended that Vectren model a smaller 440 MW CCGT option in conjunction with gas refueling of one or both A.B. Brown units in order to consider a lower capital cost alternative. This option, which replaces retired coal units with a smaller gas baseload unit, was consistent with his stated concern that implementation of large quantities of intermittent renewables could create grid difficulties and that the extension of the life of small coal units is not common in the industry.

Mr. Lind's rebuttal presented the results of additional modeling in response to the OUCC's interest in further analysis related to resource plan options including coal-to-gas conversion that would make use of the A.B. Brown unit boilers. Burns & McDonnell performed that modeling and analyzed four additional portfolios, each where the conversion of one or more units to natural gas was considered. Mr. Lind testified that this updated rebuttal modeling used the more refined cost estimates (at the plus/minus 10% confidence level) for the CCGT for comparison with the coal-to-gas conversion portfolios (which were stated at plus/minus 50% accuracy.) Mr. Lind described the results of the updated analysis and testified that when compared with the coal-to-gas conversion portfolios, the preferred portfolio still produces a lower NPV and projected customer cost. Witness Games explained that this is due in part to the high heat rates of refueled units which result in very poor dispatch rates and resulting reliance on the market for energy needs. He explained that such a portfolio would result in customers significantly depending on market purchases for energy. Witness Games testified the fuel cost per MWhr from a converted gas plant is roughly $20 more expensive than the cost from the proposed CCGT when gas price is $4.000/dkt. He showed the much higher heat rates and lower capacity factors at converted plants that were completed between 2013 through the first quarter of 2018. Mr. Games testified during the hearing that the problem of high heat rates means that the refueled units continue to cycle and ramp up and down when dispatched, leading to wear and tear and the risk of additional maintenance costs.

G. Docket Entry Question & Response. As a follow-up to the additional modeling performed by Vectren South on rebuttal of gas conversion options, we issued a Docket Entry requesting further iterations of gas conversion portfolios. These included refurbishment of Broadway Unit 2 coupled with delays of removal of Warrick Unit 4 and installation of either a simple cycle or combined cycle gas turbine. Vectren South's response included the more refined cost estimate of the CCGT at plus/minus 10%, excluded additional environmental compliance costs at Warrick Unit 4 that would allow for the delay, and were presented with and without the commitment by Vectren South on rebuttal to pass 100% of wholesale revenues to customers if the CCGT is approved. All of the additional modeling requested by our docket entry produced a higher NPV than the lowest cost refueling portfolio presented on rebuttal (to convert A.B. Brown and instill a simple cycle gas turbine). With the sharing of 100% of wholesale revenues, all of the additional modeling produced a higher NPV when compared to the preferred portfolio ranging from 3.5% to 7.0%. Given that the preferred portfolio was within 4% of the lowest cost 2016 IRP portfolio (CCGT, an additional simple cycle turbine, and delayed renewables), that means the gas conversion portfolios ranged anywhere from 8-12% higher than the lowest cost portfolio.

H. Estimated Cost of CCGT and RFP Process.

i. Vectren South. Mr. Games testified that, consistent with the 2016 IRP results, the 2017 IRP Update, and the Pace risk analysis, Vectren South is proposing to build a CCGT with 700 MW of baseload capacity and 150 MW of peaking capacity to replace retiring coal-fired capacity. Mr. Games testified Vectren South is proposing to build a unit with an output of approximately 850 MWs in order to hold some additional capacity to meet its obligations as a public utility, as well as to serve potential new customers and foster economic development. The 850 MW replaces 865 MW of retiring capacity (730 MW of baseload and 135 MW of peaking capacity, including Broadway Unit 2 in 2025). Mr. Games further testified the estimated cost of the CCGT is $781 million (+/-10%). The estimate includes owner's costs and allowance for funds used during construction ("AFUDC"). This figure was based on cost estimates developed by witness Diane M. Fischer, Central Regional Area Director and Associate Vice President with Black & Veatch. Those estimates were derived from a request for proposals for all equipment comprising the CCGT as well as construction. Mr. Games testified Vectren South is proposing to construct the new CCGT on its existing A.B. Brown generating site which will provide a conservative cost savings of $50 million resulting from reusing the existing site, facilities and equipment. He explained the critical timing of the in-service date of the CCGT which will be operational for the 2023/2024 MISO capacity year in order to retire the Culley 2 and A.B. Brown units and thereby avoid material capital investments otherwise required to operate those units beyond 2023. Similarly, the Warrick Unit 4 joint operating agreement will terminate at the end of 2023. To continue to operate Warrick would also require further investment to comply with environmental regulations.

Mr. Luttrell testified regarding the other replacement generation options Vectren South considered. He described the solicitation of competitive bids for either purchased power or ownership of all or a portion of a new CCGT unit. Mr. Luttrell explained Vectren South engaged Burns & McDonnell to manage the entire power supply RFP process, and testified this process allowed Vectren South to compare the best competitive offers for dispatchable baseload capacity to several self-build alternatives, including a partnership alternative. Mr. Luttrell testified that based on this economic and qualitative comparison, Vectren South made the decision to pursue building the duct-fired version of the proposed CCGT at the existing A.B. Brown site.

Mr. Lind testified in greater depth regarding Burns & McDonnell's role in developing and managing the RFP process to address Vectren South's power supply needs. He testified Vectren South received 11 unique proposals from six different developers. He further testified each of the conforming proposals was ranked and the top two proposals were compared with Vectren South's self-build proposals. Mr. Lind testified that based on NPV cost and qualitative risk factors, including a congestion analysis related to an off-system generation project developed by a third party, Vectren South determined that the self-build option was the best resource for reliable, long term service.

ii. OUCC. Witness Alvarez testified that, while Vectren South conducted an RFP, Vectren South did not competitively bid the actual CCGT it seeks to build in this case. OUCC witness Aguilar testified that Vectren South has not yet identified a manufacturer, chosen an exact type of CCGT, or issued any bids for the project.

iii. Coal Parties. ICC witness Medine criticized Vectren South's RFP process for a number of reasons, including the contention that Vectren South was involved in the process and the self-build project did not submit a bid as part of the RFP process. ICC witness Hayet stated a similar concern. Ms. Medine also disagreed with the position that self-build projects represent less risk than merchant projects. Ms. Medine further testified regarding the risks associated with self-builds, including cost over-runs. She testified that most if not all new Indiana plants have experienced cost over-runs that utilities look to customers to recover, and unless Vectren South is willing to guarantee costs, this is a risk that should be considered.

iv. Joint Intervenors. Witness Comings testified Vectren South did not facilitate a competitive bidding process, which limited resources and discouraged bidders from offering purchased power agreements ("PPAs"). He further testified the RFP should not have been limited to MISO Zone 6 and should have been similar to other investor-owned utility solicitations.

v. Vectren South Rebuttal. Mr. Luttrell responded to the Intervenors' criticisms of Vectren South's RFP process. With respect to Mr. Comings' criticisms that Vectren South did not facilitate a competitive bidding process, including limiting resources and discouraging bidders from offering PPAs, Mr. Luttrell testified Vectren South is retiring over 70% of its baseload capacity and the RFP was specifically designed to fill that deficiency with reliable cost-effective supply identified by the IRP. Mr. Luttrell further testified PPAs were not discouraged and all four of the responsive bidders offered a PPA. Mr. Luttrell also responded to Ms. Medine's criticisms that Vectren South was involved in many aspects of the solicitation and that Vectren South did not submit a bid as part of the RFP Process. Mr. Luttrell testified Vectren South used two separate teams—one focused on the RFP and evaluation and one focused on developing the cost estimate for the Vectren South-build CCGT—and each of these teams were separate and walled off from the other. He testified Vectren South's involvement in the RFP process was critical to help ensure the RFP would meet the needs its modeling indicated was necessary. He further testified he did not believe the RFP process was negatively impacted as a result of the self-build alternative being developed parallel to the evaluation of the RFP bids, and Ms. Medine acknowledges "there is no evidence that there was inappropriate information transfer." Mr. Luttrell explained that ultimately, an evaluation of congestion costs associated with the off-system resource proposal was the driver of selecting the CCGT project at A.B. Brown as the best option.

Mr. Luttrell also responded to Ms. Medine's position that a PPA does not pose a greater risk than having a regulated utility own the generation facility. Mr. Luttrell testified that Vectren South believes that an on-system project at an existing utility site subject to regulatory oversight and financed by a public utility, is less risky than relying on a developer. He further testified that when 70% of baseload capacity is at stake, a utility should consider all risks to project completion and to ongoing service in the long term. Mr. Luttrell provided a real-life, recent example of the risks associated with relying on a developer to construct a project. Further, Mr. Luttrell testified that a PPA does represent greater risk compared to a self-build option because the financing, construction, operation, and future financial stability of the seller is not in control of either the regulated public utility or the Commission. Mr. Lind also explained that while the cost estimate for the CCGT is stated at plus/minus 10%, the risk is actually higher (plus/minus 50%) for all portfolios that do not include the CCGT.

I. Construction of Gas Lateral to Serve CCGT.

i. Vectren South. Mr. Perry Pergola – Director, Gas Supply – testified regarding Vectren South's decision to secure the interstate pipeline services of Texas Gas Transmission ("TGT") to provide natural gas service to the proposed CCGT. He testified Vectren South selected TGT because it was the least cost pipeline option to serve the CCGT at the A.B. Brown location. Mr. Pergola further testified Vectren South will build and operate a new gas lateral to interconnect with TGT and serve the CCGT.

Mr. Steve Hoover – Director of Engineering – testified regarding the 23 mile gas lateral Vectren South will construct to connect the CCGT with TGT. He testified Vectren South will construct the pipeline itself because, by virtue of its experience building, operating and maintaining new or existing gas facilities in the Vectren South service area, Vectren South is uniquely qualified and positioned to construct the new pipeline. Mr. Hoover further testified the estimated cost to construct the gas pipeline is approximately $87 million. This is not included in the estimated cost of the CCGT as presented by witnesses Fischer and Games, as it is expected the costs of the gas pipeline will be reflected in the delivered cost of the gas.

ii. OUCC. OUCC witness Alvarez testified regarding Vectren South's proposal to build the gas lateral to serve the CCGT. He testified Vectren South did not include the costs necessary to build the gas lateral in the $781 million CCGT cost estimate and should have.

iii. Industrial Group. Industrial Group witness Gorman also testified regarding Vectren South's proposal to construct a gas lateral to serve the proposed CCGT. Mr. Gorman testified Vectren South's proposal to self-build the gas lateral is not consistent with protecting the public interest and is anti-competitive. He testified that Vectren South should have considered a third party or TGT to develop the gas lateral. Mr. Gorman testified that to the extent TGT can construct a gas lateral at a lower cost than the Vectren South self-build option, then this option should be adopted. Mr. Gorman further testified that Vectren South's proposal to recover the pipeline costs as part of the fuel costs for the CCGT is not reasonable because the fixed cost to build the gas lateral will not vary with energy generation or volume of gas delivered to the CCGT. He testified instead it would be appropriate to allocate the gas lateral cost as part of the CCGT fixed capital cost of the facility and allocate it on a capacity basis.

iv. Coal Parties. ICC witness Medine testified regarding Vectren South's proposal to construct the gas lateral. Ms. Medine characterized Vectren South's proposal as a proposal to build the lateral using an affiliate without competitive bidding. She also criticized Vectren South's decision to self-build the gas lateral instead of soliciting bids from third parties. Ms. Medine testified that Vectren South did not solicit bids for the lateral from third parties, and, therefore, it cannot represent that it was the lowest cost option for the construction of the lateral.

v. Vectren South Rebuttal. Vectren South witness Steve Hoover responded to criticisms raised by the Intervenors related to Vectren South's proposal to construct the gas lateral. Mr. Hoover testified that Ms. Medine's characterization of the proposal as an "affiliate transaction" has no bearing on the overall substance of the proposed transaction because there are many reasons why it is advantageous for Vectren South to construct the gas lateral. He reiterated that the Vectren South engineering, land services, and construction management teams have already successfully completed two similar projects to deliver gas to Duke Edwardsport and IPL Eagle Valley generating units. He testified it is therefore in the best interest of Vectren South's customers for it to enlist the experience and expertise of its gas utility in the pipeline construction and operations. Mr. Hoover also responded to criticisms raised by witnesses Gorman and Medine that the lateral project is anti-competitive and being conducted without competitive bidding. Mr. Hoover testified that Vectren South requested TGT to provide a cost estimate to construct the lateral early in the process, and TGT's cost estimate was 10-15% higher than Vectren South's estimate. He further testified that Vectren South will complete a competitive procurement process to select a contractor to construct the lateral. Mr. Hoover testified that during the course of bidding and the evaluation process, Vectren South will also incorporate cost protections and performance incentives to ensure both competitive and fair pricing.

Mr. Hoover also responded to Mr. Gorman's preference that the lateral be placed in Vectren South's rate base as opposed to the costs being recovered via the Fuel Adjustment Clause ("FAC"). Mr. Hoover testified that like IPL and Duke, Vectren South has chosen to have a qualified local distribution company ("LDC") own and operate its gas delivery pipeline. Therefore, the pipeline will not be an electric utility asset and the costs associated with it will be recovered through gas rates.

As to the allegation that Vectren South's owning the gas pipeline as a gas utility asset is anti-competitive, witness Pergola testified on cross-examination that nearly all of the pipeline (more than 22 of the 23 miles of length) is located in Kentucky and therefore presents no opportunity for bypass, because Vectren South does not possess the right to serve customers in Kentucky.

J. Warrick Unit 4.

i. Vectren South. Mr. Wayne Games testified regarding the uncertain future of Warrick Unit 4. Mr. Games explained that Vectren South and Alcoa co-own the unit pursuant to a Joint Operating Agreement ("JOA") whereby each has 50% ownership in the unit. Mr. Games testified that while Warrick Unit 4 will continue to operate in the near term, the long term outlook for the unit is uncertain. He testified the future of the unit is tied to the Alcoa industrial site, and at any time Alcoa could decide to close the smelter unit, which utilizes significant quantities of electricity produced by Warrick Unit 4, based on price volatility in the aluminum market. He testified that the decision to shut down the smelter unit would jeopardize the future of Warrick Unit 4 and this uncertainty makes it difficult to justify investment in the unit or to depend upon it in the long run.

Vectren South witness Carl Chapman also testified regarding the future of Warrick Unit 4. Mr. Chapman testified that Vectren South has agreed to retain its involvement in the unit through 2023 to support the re-opening of the Alcoa smelter. However, he testified beyond 2023 it does not makes sense to continue to invest in a unit that could be subject to shut down if Alcoa decides it has no continuing need for the capacity.

ii. OUCC. OUCC witness Aguilar testified regarding Warrick Unit 4. Ms. Aguilar testified she does not agree with Vectren South's assessments of the risk of continuing to operate Warrick Unit 4 under the JOA and she disagrees with Vectren South's "presentation of the agreement." She further testified that Vectren South could continue to operate Warrick Unit 4 beyond 2023 with environmental compliance updates.

iii. Vectren South Rebuttal. Mr. Games responded to OUCC witness Aguilar's contention that Vectren South could continue to operate Warrick Unit 4 beyond 2023. He testified that due to compliance requirements coming in Alcoa's next National Pollutant Discharge Elimination System ("NPDES") permit, it is anticipated that the unit will require significant capital investment to meet environmental standards in the future. He testified that these investments coupled with the uncertainty related to whether Alcoa will continue to operate Warrick Unit 4[3] under the JOA and performance issues at the unit, warn against continued reliance on Warrick Unit 4.

Mr. Chapman also testified regarding the continued operation of Warrick Unit 4. He testified that the partnership with Alcoa jointly to operate Warrick Unit 4 has become highly uncertain in terms of duration and no longer represents a viable long-term resource option. Mr. Chapman further testified that while Vectren South's IRP recommended retirement of Warrick Unit 4 well before 2023, Vectren South examined each of the coal units to determine whether such units should be retained. He testified that while Culley 3 and Warrick Unit 4 had better profiles in terms of environmental equipment as compared to Vectren South's other units, Culley 3 ultimately had a better operating history based on cost, availability and heat rate. Mr. Chapman reiterated that a strike against continued operation of Warrick Unit 4 is the uncertainty surrounding the longevity of the Alcoa partnership. He reiterated the continued operation of Warrick Unit 4 is dependent on the aluminum market, and if Alcoa's industrial operations cease at the site, the environmental requirements facing Warrick Unit 4 will become significantly more stringent. Mr. Chapman ultimately testified the bottom line is assuming Warrick Unit 4 can continue on post-2023 presents great risk.

As noted previously, in response to our Docket Entry question seeking additional modeling of a portfolio with delayed retirement of Warrick Unit 4, Vectren South indicated that an additional capital investment cost of as much as $50 million may be required to retain the unit if IDEM determines not to renew a variance in the unit's current NPDES permit that allows water discharge at a higher temperature. The new draft renewal NPDES permit allows IDEM to terminate this variance at any time, which will likely require the construction of a cooling tower. Coupled with both Alcoa's and Vectren South's ability to terminate the joint operating agreement, this even further increases the risk of reliance on Warrick Unit 4 beyond 2023.

K. **Culley Unit 3.** While making investments to preserve some coal-fired generation is not part of the lowest NPV under the 2016 IRP modeling, Vectren South proposes to make investments at Culley Unit 3, its most efficient plant, in order that it may continue to operate beyond 2023. This decision became part of the preferred portfolio as a result of the risk assessment in the 2016 IRP. Preserving Culley Unit 3 promotes greater diversity in fuel sources and it also lessens the impact on the local coal industry. Witness Retherford described the environmental controls that are needed as a result of CCR and ELG. The Culley 3 Compliance Projects consist of (1) conversion of the current wet bottom ash collection system to a dry handling bottom ash system; (2) installation of a spray dryer evaporator system; and (3) the closure of the Culley West ash pond and construction of a new lined process water and storm water retention pond in its place. This new retention pond will be constructed on the location of the existing ash pond due to space limitations. Witness Fischer developed the cost estimates for the former two and Ms. Retherford provided the cost estimate for the latter. Recovery of the associated costs through a rate adjustment mechanism under Ind. Code ch. 8-1-8.4 was opposed by OUCC witness Aguilar and Industrial Group witness Gorman.

[3] With proper notice, Alcoa can also terminate the JOA.

4. **<u>Pending Summary Judgment Motion and Motion to Dismiss under T.R. 41(B)</u>.** On July 19, 2018, the Coal Parties, Joint Intervenors, Evansville Western Railway, the OUCC, and the Industrial Group filed a Motion for Summary Judgment asking the Commission to vacate the schedule, arguing that we cannot grant Vectren South's request for authority to construct facilities until we have completed a "final" statewide analysis pursuant to Ind. Code § 8-1-8.5-3(a). Alternatively, the Movants asked us to grant them an extension of time to file their pre-filed testimony until at least 45 days after we post a "final" statewide analysis. We took the matter under advisement. At the conclusion of Vectren South's case-in-chief, Alliance Coal made an oral motion to dismiss under T.R. 41(B) on the same grounds. The T.R. 41(B) motion was joined by the OUCC and all of the other Movants except the Industrial Group and Evansville Railway.

In construing a statute, we start with its plain language and "attempt[] to give words their plain and ordinary meanings." *Indiana Wholesale Wine & Liquor Co., Inc. v. State ex rel. Indiana Alcoholic Beverage Com'n*, 695 N.E.2d 99, 103 (Ind., 1998) (citations omitted). "[I]n seeking to give effect to the legislature's intent, [the court] read[s] an act's sections as a whole and strive[s] to give effect to all of the provisions so that no part is held meaningless if it can be reconciled with the rest of the statute." *Fort Wayne Patrolmen's Benev. Ass'n, Inc. v. City of Fort Wayne*, 903 N.E.2d 493, 497 (Ind. Ct. App., 2009) (citation omitted).

The Motion is based primarily on Section 3(a) of Ind. Code § 8-1-8.5, which provides that "[t]he Commission shall develop, publicize, and keep current an analysis of the long range needs for expansion of facilities for generation of electricity," and Section 3(c), which provides that "[t]he commission shall consider the analysis in acting upon any petition by any utility for consideration." The Movants interpret these provisions to mean that we cannot consider a certificate of public convenience and necessity ("CPCN") request absent a "final" statewide analysis. We disagree.

Neither provision requires or implies there must be a "final" or conclusive statewide analysis. Nor does any other provision in Chapter 8.5. Section 3 directs us to undertake an "analysis" that is subject to ongoing review and revision. An analysis that must remain "current" cannot possibly remain static or culminate in a finished product. We find that the analysis detailed in the draft and final versions of the Statewide Analysis meets the requirements of the statute.

To the extent the Movants argue that we cannot grant Vectren South's Petition until we complete our annual report on the analysis, their Motion also fails.

Section 3(h) requires us "[e]ach year" to "submit to the governor and to the appropriate committees of the general assembly a report of its analysis regarding the future requirements of electricity for Indiana or this region." Ind. Code § 8-1-8.5-3(h). Section 5(b)(2) provides that a certificate may be granted if the Commission finds the project (A) "will be consistent with the Commission's analysis (or such part of the analysis as may then be developed, if any)"; or (B) is "consistent with a utility's specific proposal submitted under Section 3(e)(1) of this chapter and approved under subsection (d)." Ind. Code § 8-1-8.5-5(b)(2)(A) and (B).

This unambiguous language reflects the Legislature's understanding that new generation needs may arise at a time while the analysis or even the annual report is being developed or under revision. The Legislature granted the Commission authority to issue a CPCN rather than hold the request in abeyance until the annual report is issued.

It must be presumed that "'the legislature intended the language used in the statute be applied logically and not to bring about an unjust or absurd result.'" *D.B. v. Review Bd. of Indiana Dept. of Workforce Development*, 2 N.E.3d 705, 710 (Ind. Ct. App., 2013) (quoting *Penny v. Review Bd. of Ind. Dep't of Workforce Dev.*, 852 N.E.2d 954, 960 (Ind. Ct. App., 2006), trans. denied). Reviewing bodies also avoid "interpreting a statute in such a manner as to render its provisions mere surplusage." *Id.* (citing *In re Adoption of D.C.*, 887 N.E.2d 950, 959 (Ind. Ct. App., 2008). The Legislature cannot have meant for the Commission to hold off assessing petitions until its analysis becomes "final" (which will never occur), or even until its annual report is submitted. Thus, the statute is clear that in considering a CPCN request, pursuant to Section 5(b)(2) we can rely on whatever current statewide analysis exists or simply determine whether the proposal is consistent with the utility's own plan and reports.

In sum, the Commission retains authority to review a project at any time. Ind. Code § 8-1-8.5-5.5 expressly allows us to "commence a review of any certificate granted under this chapter" when, "in the opinion of the commission, changes in the estimate of the probable future growth of the use of electricity" call for such review. Further, "[i]f the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate." Id.

For all of the foregoing reasons, and each of them, the Motions for Summary Judgment and for Dismissal under T.R. 41(B) are denied.

5. **Commission Discussion and Findings.**

A. **Vectren South's Request for a CPCN for a CCGT.** Vectren South requests a CPCN for a proposed CCGT (approximately 850 MW) to be constructed at the current site of the A.B. Brown power plant in Posey County. Under Chapter 8.5, a public utility may not begin the construction, purchase or lease of any steam, water, or other facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service without first obtaining from the Commission a certificate that public convenience and necessity requires, or will require, such construction, purchase or lease.

In considering a CPCN request, Chapter 8.5 requires the Commission to consider options other than the construction, purchase, or lease of an electric generating facility. *See* Ind. Code § 8-1-8.5-4.

Further, Ind. Code § 8-1-8.5-5 sets forth specific findings the Commission must make in order to approve and grant the requested CPCN. First, the Commission must make a finding, based on the evidence of the record, as to the best estimate of construction costs. Second, the Commission must find that either (a) construction will be consistent with the Commission's Statewide Analysis, if any, for the expansion of electric generation facilities, or (b) the proposed construction is consistent with a utility-specific proposal as to the future needs of consumers in the State of Indiana or in the petitioning public utility's service area [i.e., the utility's IRP]. Third, the Commission must find that public convenience and necessity require the facilities for which the CPCN is requested.[4]

[4] A fourth finding relating to coal-consuming facilities, pursuant to Ind. Code § 8-1-8.5-5(b)(4), does not apply to the proposed natural gas facilities.

"We have indicated in previous CPCN cases that 'least-cost planning' is an essential component of our [CPCN] law." *Joint Petition of PSI Energy, Inc. and CINCAP VII, LLC*, Cause No. 42145, at 4 (IURC Dec. 29, 2002), *quoting Southern Indiana Gas & Electric Co.*, Cause No. 38738, at 5 (IURC Oct. 25, 1989). "We have defined 'least-cost planning' as a 'planning approach' which will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined." *Id.* "However, we have emphasized that the [CPCN] statute does not require the utility to automatically select the least cost alternative. Nor does the statute require the utility to ignore its obligation to provide reliable service or to disregard its exercise of reasonable judgment as to how best to meet its obligation to serve." *Id.* As this Commission has previously ruled: "[i]f an Indiana utility reasonably considers and evaluates the statutorily required options for providing reliable, efficient, and economic service, then the utility should, in recognition that it bears the service obligations of IC 8-1-2-4, be given some discretion to exercise its reasonable judgment in selecting the option or options to implement which minimize the cost of providing such service." *PSI Energy, Inc.*, Cause No. 39175, at 14 (IURC May 13, 1992); *see also Joint Petition of PSI Energy, Inc. and CINCAP VII, LLC*, Cause No. 42145, at 4.

The pre-approval of long-lived power plant investment and the concurrent regulatory assurance of that investment's recovery is, at its base, the creation of fixed costs that customers will be required to pay several years into the future, perhaps as long as 30 years or more into the future. Accordingly, our consideration in this and other pre-approval requests, especially in periods of seemingly quickening technological change, must not ignore the risk that any such investment may become uneconomic over the long-term. We must acknowledge that the economic forces at work may come from other supply side options or even demand side opportunities. The supply side and demand side certificating statutes implicate this by recognizing that an optimal balance of energy resources should consider both aspects in meeting customer needs.[5] A complication in the optimizing effort is the often disparate time horizons of the supply and demand sides of the balance. The inability to adjust the long-lasting nature of the supply side of the equation in the event market conditions or demand side expectations change in a lesser time horizon introduces a risk that some measure of the supply side investment may become uneconomic within its lifetime.[6] Demand side efforts by customers as a result of the uncontroverted improving economics of customer-scale generation resources may further compound the challenge of the optimal balancing act. Reducing demand in the near term does not necessarily correspond with reduced assured supply side investment cost recovery.[7] Because unwinding assured cost recovery should an asset become uneconomic is not a commonly employed regulatory option, it is prudent to ensure during the pre-approval process that we understand and consider the risk that customers could sometime in the future be saddled with an uneconomic investment. Outcomes that reasonably minimize such potential risk and serve to foster utility and customer flexibility in an environment of rapid technological innovation on both the utility and customer side of the meter are, therefore, a lens through which we will review Vectren South's request.

[5] Indiana Code §§ 8-1-8.5-4 and -10(c)(3).

[6] This effect can be see through the recovery of lost revenues a statutory component of utility DSM programs, which is in part a function of investment, of fixed cost, that is not being consumed at the expected rate.

[7] This timing inconsistency can reduce the value of demand side efforts because they are not avoiding long-lived fixed costs previously approved and included in rates. The full incremental impacts of demand side actions which occur after the approval of long-lived fixed costs are only affected over longer periods of time when future resources must be acquired and the timing and type of resource might change as a result of cumulative demand side activities.

i. Ind. Code §§ 8-1-8.5-4.

(1) Ind. Code § 8-1-8.5-4(1). In evaluating a utility application for approval to construct new generation, the Legislature has directed us to take into account the utility's "current and potential arrangements with other electric utilities for (A) the interchange of power; (B) the pooling of facilities; (C) the purchase of power; and (D) joint ownership of facilities."

As a member of MISO, Vectren South interchanges power on a daily basis, and Vectren South's modeling considered and factored this arrangement into its decision to seek a CPCN. In addition, early in its resource selection process Vectren South identified a potential partner for a joint generation project. Witness Luttrell explained that this partner was interested in owning a minority share of a larger CCGT, and agreed to study locating such a unit on Vectren South's system. As studies ensued, the partnership appeared to be a viable resource option. As a result, the parties studied this joint ownership opportunity throughout 2017, but ultimately in January 2018 the potential partner provided notice that it would not proceed with such a project. Both Vectren South and the Commission have considered the interchange of power and pooling of facilities.

When assessing a CPCN petition, the Commission also considers the potential purchase of power by Vectren South. On June 20, 2017, Vectren South issued a RFP for dispatchable resources located in MISO Zone 6. Vectren South explained that its RFP specified this location requirement in order to satisfy MISO's requirement that a load serving entity have at least 67% of its resources located within its zone. The RFP sought dispatchable resources based upon the 2016 IRP analysis, which recommended that Vectren South retire nearly all of its baseload coal-fired capacity by the end of 2023. As a result, the RFP was designed to solicit baseload capacity to replace the 730 MWs provided by the retiring coal units. In response, Vectren South received nine qualified bids offering both PPAs and offers to build a CCGT and sell that unit or a partial interest in that unit to Vectren South. Using the expertise of Burns & McDonnell ("BMC"), Vectren South evaluated both quantitative and qualitative aspects of the competing bids. Based on BMC's analysis of the levelized cost of energy ("LCOE") of the bids, Vectren South selected the bid with the most favorable LCOE to compare to a self-build option. BMC's analysis was that Vectren South's self-build option had a better net present value than this best bid, and also exposed Vectren South to less risk versus long-term reliance on a merchant developer. Vectren South's rebuttal testimony noted that the merchant developer in question had in fact, even prior to its bid submission, withdrawn its project from the MISO queue without informing Vectren South.

The Commission acknowledges Vectren South's issuance of an RFP but believes the RFP was unduly restrictive given the rapid changes in technology and costs being seen in the market, especially regarding renewable energy. The narrow RFP with its focus on a large baseload dispatchable resource limited the options Vectren South evaluated to those larger than 600 MW. As a result, Vectren South foreclosed consideration of combinations of smaller resources that might have offered greater resource diversity, flexibility and cost efficiencies than reliance on the acquisition of a single large natural-gas facility. As discussed further below, expansion of the RFP to consider a broader spectrum of resource options would have also gone a long way to improve the metrics to limit risks from exposure to changes in market conditions and technologies.

Based on Vectren South's unduly restrictive RFP the Commission cannot conclude that Vectren South thoroughly evaluated the purchase of power in connection with Vectren South's request.

(2). Ind. Code § 8-1-8.5-4(2).

(a) The Refurbishment of Existing Facilities. In acting upon a petition for the construction of an electric generation facility, we must consider other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities. Ind. Code § 8-1-8.5-4(2). Ms. Aguilar summarized the following alternatives that Vectren South failed to fully analyze: (1) Retain Coal at Vectren South's existing plants and invest in refurbishments; (2) Retain the agreement with Alcoa for Warrick Unit 4; (3) Refuel the A.B. Brown unit(s) with gas; (4) A blended option, such as refueling one or more A.B. Brown units to gas and building a smaller CCGT; (5) Enter into a PPA with one of the bidders who responded to Vectren South's RFP; and (6) Retain its Broadway Avenue Unit 2. Pub. Ex 1, p. 8. Ms. Aguilar argued that Vectren South unfairly screened out these alternatives during the IRP process.

We agree with Ms. Aguilar and Dr. Boerger that Vectren South did not fully consider options to extend the life, or refurbish, existing units as required by Ind. Code § 8-1-8.5-4(1). *Id.* and Pub. Ex. 3, p. 6. This failure began during Vectren South's IRP process, when Vectren South screened out, without further study, viable refurbishment options. Pub. Ex. 1, p. 11. Vectren South's stated reason for shutting down the A.B. Brown units is premised on the need to replace the flue-gas desulfurization ("FGD") units at a cost of approximately $350 million. Pub. Ex. 3, p. 7. Dr. Boerger stated that with the exception of the current FGDs, the units operate quite well and are sized appropriately for a small utility like Vectren South. But as noted by Ms. Aguilar and Dr. Boerger, Vectren South's chosen FGD replacement technology was the most expensive and only technology reviewed. *Id.*, Pub. Ex. 3. Dr. Boerger pointed out that Vectren South did not consider lower-cost FGD replacement options, even though such options were available. He said that this decision made the continued use of the A.B. Brown units look less attractive in modeling than if those options had been included. A reasonable alternative would have been the refurbishment of these units through refueling. Pub. Ex. 3, p. 7. Refueling is viable, proven technology that could be accomplished at a fraction of the price of the CCGT – approximately $45 million for both A.B. Brown units.

Vectren South considered a smaller 440 MW CCGT option in its last IRP, but Vectren South did not include it as part of any refueling options. Pub. Ex. 3, p. 9. Further, when Vectren South issued its RFP, it did so for 600-800 MW of dispatchable power, precluding smaller units that might have combined with refurbishment of other Vectren South units. Tr. B-25 - B-26. Vectren South did not fully model the conversion of one of the A.B. Brown units in its rebuttal testimony. Tr. E-45 – E-46.

On cross-examination, Vectren South witness Mr. Swiz estimated that the value of the stranded assets at the A.B. Brown unit alone will equal $220 million and that the system-wide total will be $270 million. While Vectren South argues that the CCGT option is the lowest cost, we find for the many reasons stated throughout this Order, including Vectren South's failure to sufficiently consider the refurbishment and continued operation of its existing facilities, we are not able to verify this claim. Through the lens of minimizing risk and providing future flexibility the refurbishment option would seem to provide a potential bridge to the future, providing system capacity value that was not sufficiently evaluated. This conservative solution and risk avoidance strategy stands in stark contrast to proposed CCGT. Vectren South plans to submit a new IRP in 2019. We instruct Vectren South to closely consider our analysis in this Order and the Director's Report on the 2016 IRP of the flaws in their modeling for the 2016 IRP and the 2017 IRP Update and to present a more thorough analysis that fully evaluates all possible options for continuing to provide reliable, efficient, and economical electric service.

(b) Conservation and Load Management. The evidence demonstrates that Vectren South has evaluated the CCGT against other reasonable generation alternatives, and included demand side management and energy efficiency ("DSM/EE") levels consistent with the targets approved in Cause No. 44927. Vectren South's modeling concludes that, even when the cost of energy efficiency has been significantly lowered, the CCGT is still the least cost reliable resource alternative to meet Vectren South's customers' future energy resource needs.

The Joint Intervenors criticize the assumptions used by Vectren South to model the cost of DSM/EE, arguing that the assumptions used by Vectren South were too high resulting in a higher cost of DSM/EE. Ms. Harris stated in her rebuttal that for purposes of this proceeding, Vectren South opted only to update its growth factors in its revised cost analysis in order to show the impact lower DSM/EE costs would have on the energy resources selected in its IRP. Ms. Harris explained that limiting the updates to the growth factors preserved the integrity of Vectren South's 2016 IRP. Petitioner's Exhibit No. 8-R, p. 3. We find that while some of the cost assumptions used by Vectren South could have been updated, on the whole it does not render Vectren South's analysis of DSM/EE unreasonable.

(c) Cogeneration and Renewable Energy Sources. Vectren South's IRP modeling process considered the potential for cogeneration facilities to serve its customers and adjusted its load forecast to reflect the potential for cogeneration facilities. Petitioner's Exhibit No. 5, Attachment MAR-1, pp. 99-103. Consequently, the potential for customer-owned generation resources, including renewable generation, to reduce Vectren South's load was evaluated as part of the IRP process that concluded the CCGT was necessary as part of least-cost planning. Nonetheless, while Vectren South may have considered renewable energy in the IRP, there is a lack of evidence that Vectren South made a serious effort to determine the price and availability of renewables. In addition, the economics of customer-scale renewable and cogeneration facilities appears likely to continue to improve and we anticipate that additional well-developed efforts to understand their customers' interest would serve to provide clarity to the lens of risk avoidance by minimizing the potential for unexpected demand side efforts. Therefore, we would expect Vectren South to ensure an enhanced consideration of renewable energy and customer-generator opportunities in future IRPs.

(3) Ind. Code § 8-1-8.5-5. A certificate may be granted only if the Commission makes the followings findings:

(a) Best estimate of construction, purchase, or lease costs based on the evidence of record. The cost estimates for Vectren South's proposed CCGT were developed and presented by witness Diane Fischer. Black & Veatch developed a design basis and conceptual design and thereafter developed a cost estimate. Several conceptual designs were first developed. From that, ten plant alternatives for purposes of estimating costs were identified. This was later narrowed to seven alternatives for which detailed costs were developed. Competitive bids were obtained for the equipment and materials. Based upon Black & Veatch's experience as an engineering, procurement and construction ("EPC") contractor, Black & Veatch was able to estimate indirect costs, contingency, overhead, and profit for the EPC contractor. Bids were also received for construction. Ultimately, Ms. Fischer testified that the cost estimate for the proposed CCGT had been refined to +/- 10%. The total estimated project cost (excluding owner's costs) was $582,000,000. The owner's costs were then provided by witness Games, including insurance, contingency, study, and AFUDC. The total cost estimate was $781,000,000.

(b) Consistency of the CCGT with Vectren South's Utility-Specific IRP and the Statewide Analysis. Ind. Code § 8-1-8.5-5(b)(2)(A) directs the Commission to determine whether Vectren South's proposed construction of a new CCGT will be consistent with the Commission's 2018 Statewide Analysis. The final version of that report was issued after the parties' pre-filing deadline, but before the evidentiary hearing and was admitted into evidence as Pet. Admin. Not. Ex. 2. Included in that report is a synopsis of information taken from the most recent IRP projects of Indiana utilities, including Vectren South.

In Appendix 12 of the Statewide Analysis, the concept of Resource Diversity is explained:

> In an electric system, resource diversity may be characterized as utilizing multiple resource types to meet demand. A more diversified system is intuitively expected to have increased flexibility and adaptability to: 1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks. In this way, resource diversity can be considered a system-wide tool to ensure a stable and reliable supply of electricity. Resource diversity itself, however, is not a measure of reliability. Relying too heavily on any one fuel type may create a fuel security or resilience issue because the level of resource mix diversity does not correlate directly with a resource portfolio's ability to provide sufficient generator reliability attributes.

Vectren South's proposal to concentrate its base load capacity from five different generating units located at three different sites down to just three generating units (one of them constituting 70% of Vectren South's baseload capacity) located at two sites appears to be contrary to the concept of resource diversity.

On page 5 of the 2018 Statewide Analysis it says:

> A key consideration in long-term resource planning is the need to retain maximum flexibility in utility resource decisions to minimize risks. An IRP developed by a utility should be regarded as illustrative and not a commitment for the utility to undertake.

In explaining the importance of sound long-range planning on page 56 of the 2018 Statewide Analysis, it says, "[t]he credibility of the analysis is critical to the efforts of Indiana utilities to maintain as many options as possible, which includes off ramps, to react quickly to changing circumstances and make appropriate changes in the resources." However, we find nothing in Vectren South's evidence convinces us that its proposal provides any off ramps that would allow Vectren South to react to changing circumstances and make appropriate changes in resources. To the contrary, Vectren South's proposal seems to close most off ramps for the foreseeable future.

The parties offered diametrically opposed views on the modeling offered to support the CPCN, with Vectren South pointing to its CCGT conclusion as consistent with its IRP. But that conclusion is but one part of the analysis. We have criticized utilities in the past for modeling infirmities and even penalized a utility for analysis we found lacking. In IPL's MATS case, we ordered a $10 million credit to customers to "send[] an appropriate message" to the utility. *Indianapolis Pwr. & Light Co.*, Cause No. 44242, 2013 WL 4479081 *38, 307 P.U.R.4th 311, Order p. 36 (IURC Aug. 14, 2013). We found IPL's cost/benefit study "disappointing" and noted our own "responsibility to insure that the regulatory process involves the presentation of the best evidence possible, given the facts and circumstances of a particular case." *Id.* at 35.

At the outset, Mr. Games testified that Vectren South sent a request for information ("RFI") to original equipment manufacturers ("OEM") for CCGT pricing information before Vectren South's 2016 IRP. Tr. E-89 – E-91. Mr. Chapman stated that under any of the IRP models, the CCGT is the least expensive. Tr. A-27 - A-28.

Dr. Boerger testified that Vectren South did not consider other viable options such as refueling and smaller combinations of generation assets to meet its needs, Pub. Ex. 3, p. 1 – p. 2, which would be more prudent for a small utility like Vectren South. Pub. Ex. 3, p. 5. Vectren South excluded possible options such as maintaining Culley 2, Pub. Ex. 3, pp. 11-12, and did not allow the refueling of the A.B. Brown units to be included in any of its model runs. *Id.* Vectren South kept a smaller, 440 MW CCGT from being combined with a refueled A.B. Brown unit. Pub. Ex. 3, p. 13. Mr. Games admitted that Vectren "never [ran] a risk analysis of portfolios including a 1 X 1 CCGT instead of a 2 X 1[.]" Tr. E-50. Vectren South also did not allow for proposals of joint projects to be built at it's A.B. Brown site, which would eliminate the potential for congestion problems Vectren South identified as a problem in its RFP responses. Vectren South's Strategist model limited the amount of capacity purchases that a given portfolio could make. Tr. D-73. This had the effect of automatically screening out PPAs that could have been combined with other resources to meet Vectren South's capacity needs. The Director's Report on Vectren South's 2016 IRP noted that Vectren South failed to model a wide range of gas prices, making the "range of fuel price projections… unduly limited[,]" Tr. D-85, and Vectren South's re-run of gas costs did not model higher prices in a wide enough range. Tr. D-86. As noted by Mr. Alvarez, Vectren South's model retired the BAGS 2 unit in 2024 without evidence of any engineering reason to do so. Pub. Ex. 2, pp. 13-14.

Dr. Boerger also found that Vectren South modeled the cost of its proposed CCGT to be $200 million less than the cost of the project presented in the testimony of Vectren South witness Games. Pub. Ex. 3, p. 2. The consequence of excluding $200 million in Vectren South's NPV calculation had the effect of making the CCGT option look more favorable. Pub. Ex. 3, p. 14. Without adding the $200 million back into the model runs, Vectren South's analysis is skewed. Pub. Ex. 3, p. 18 – p. 19. Mr. Games admitted that his testimony about the estimates was confusing, stating "[w]e started off with 2017 dollars, and those were -- then overheads were added, anticipated profit with the EPC, contingency for EPC, and escalation was added to get to the 582 million." Tr. E-15 – E-16. Mr. Lind took issue with Dr. Boerger's analysis, but admitted that Vectren South did not include $130 million in owner's costs when it compared its self-built CCGT to other options offered in the RFP and otherwise. Tr. A-36 – A-38; Tr. D-7 – D-8. When questioned why BMC did not use the $781 million figure, Mr. Lind stated that the $630 million estimate used for modeling was a +/- 50% estimate; the $781 million had a more certain +/- 10% range of accuracy. Tr. A-35; Tr. C-61 - C-62, C-74. BMC's projected cost of $580 - $650 million was used to weigh the economics of potential projects. Tr. A-

36 – A-38. And Vectren South witness Mr. Vicinus ran his "low regulatory" model using the $630 million estimate. Tr. D-98.

In response to the OUCC's criticism of its modeling, Vectren South's rebuttal included a new model run that refueled one of the A.B. Brown units, and added 200 MW of solar. Tr. D-12 – D-13. Vectren South used this rebuttal modeling to try to reinforce its original request for a 850 MW CCGT. Both Mr. Lind and Mr. Games acknowledged, however, that the addition of 200 MW of solar was not the best choice to meet MISO's PRM, because MISO would only give Vectren 100 MW of credit for the 200 MW of solar. Tr. E-15. The revised model also did not take into account the fact that solar costs between $1,200 - $1,800 per MW, Tr. D-16 – D-17, and Vectren South did not model any storage to counter the inherent intermittency of solar resources. Tr. D-14.

While we find Vectren South's request is "consistent" with its 2016 IRP, the subsequent modeling for this case effectively screened out multiple less-expensive alternatives. Vectren South did not allow its models to choose refueling or smaller units in combination. While Vectren South's rebuttal modeling runs included refueling of the A.B. Brown units in various configurations, the rebuttal modeling was not used to make Vectren South's decision of what generation form to choose. Tr. D-14. We view the rebuttal modeling as an after-thought used to buttress Vectren South's initial request.

Vectren South had sufficient time to conduct its analysis in a way more open to smaller-scale options that would correct the modeling deficiencies that have been identified. It seems straightforward to suggest that smaller-scale options, especially for a relatively small electric utility, serve to minimize the risk should a challenge arise at any one option. As noted above, minimizing supply side long-term investment risk in an environment of rapid technological innovation is an attractive characteristic in a utility resource proposal. Vectren South should use its scheduled 2019 IRP process to address problems in its modeling, incorporate more options for partnering with other entities and competitive inquiries into smaller-scale options that can be acted upon swiftly to meet the end-of-2023 date upon which additional capacity may be needed.

(c) Public Convenience and Necessity. Ind. Code § 8-1-8.5-5(b)(2) requires that we find that public convenience and necessity requires or will require the proposed CCGT. Such consideration of the public interest is not only a statutory requirement at the outset but would become a continuing obligation should the Commission grant a CPCN. Ind. Code § 8-1-8.5-5.5 provides that if, after granting a CPCN for construction of a new generator, "the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate."

"[P]ublic interest may be taken to encompass a wide range of considerations, from environmental, health, and safety concerns, to the financial concerns of employers, employees, and ratepayers." *General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752, 762 (Ind. Ct. App., 1995). In *General Motors*, the court approved the Commission's consideration of the impact on employment in the coal industry in its public interest determination. *Id.*

The parties dispute whether Vectren South accurately and adequately evaluated risk in its analysis of alternative portfolios and selection of the proposed CCGT. As noted earlier, under Ind. Code § 8-1-8.5-4, we are required to take into account other methods for providing reliable, efficient, and economical service, and we find utility risk analyses play an important role in comparing alternative portfolios.

Joint Intervenors argued that Vectren South's risk analysis is inadequate for multiple reasons. Joint Intervenors note that the risk analysis has not been updated since the 2016 IRP, despite Vectren South having updated inputs available for several inputs, including the estimated cost of its preferred build, and adequate time to re-run the model. Joint Intervenors complain that Vectren South ignored known material risks in a manner that biased results in favor of its preferred portfolio, including taking a one-sided view of capacity purchase and market purchase risks and failing to consider the potential for future methane regulations. Joint Intervenors further argue that Vectren South arbitrarily scored several metrics and designed others to conceal rather than measure obvious risks of the preferred portfolio.

We find merit in several of Joint Intervenor's critiques and are further concerned that Vectren South has not fully responded to critiques in the Final Director's Report on the 2016 IRPs. We agree that Vectren South had adequate time and opportunity to update its risk analysis modeling prior to this filing, and that it has sufficient time to do so now before moving forward. Vectren South updated inputs in its possession for multiple factors, including: solar capital costs; variable production costs and revenue requirement assumptions for existing units; forecasted cost for wholesale market capacity and energy; delivered fuel prices for gas and coal; and costs associated with new energy efficiency programs. Pet. Ex. 6 at 9-10. Vectren South also had a higher capital cost estimate for its preferred build. We know Vectren South had time to use these inputs to re-run the model because (a) it did just that with some of its Strategist modeling and (b) Mr. Vicinus testified that it would have taken just three months to re-run the risk analysis modeling. Tr. p. D-66. Mr. Vicinus opined that updated risk modeling would not change the result, but we are skeptical given the number and import of the updated inputs and the significance of the proposed portfolio changes. *See Indianapolis Pwr. & Light,* Cause No. 44339, 2014 WL 2091348, Order p. 27 (IURC May 14, 2014) ("[W]e believe that IPL could have reasonably updated the [model] given the extent of changes in data inputs and assumptions and provided a more robust analysis."). Before proposing a portfolio change of this magnitude, Vectren South should have taken the three months necessary to update its risk analysis modeling. Updated risk modeling may not be necessary in all cases, but it is warranted here given the size and cost of the proposed CCGT.

We are further concerned that Vectren South appears not to have accounted for material risks associated with its preferred portfolio. As we have previously stated, "it is appropriate that modeling take into consideration reasonable risks and unknowns." *Indianapolis Pwr. & Light Co.*, Cause No. 44794, 2017 WL 1632316, Order p. 28 (IURC Apr. 26, 2017). Joint Intervenors point out that Vectren South's risk analysis took a one-sided view of capacity purchase and market purchase risks. *See* JI Ex. 2 at 43; Vicinus Rebuttal. Vectren South offered no rebuttal explaining its one-sided view of market risk, which assumed surplus capacity and generation offers only benefits to ratepayers. JI Ex. 2 at 20-21. That view of market purchases is only true when market prices and/or load are high. JI Ex. 2 at 21. Further, Vectren South's Docket Entry response of October 5, 2018, presents portfolio results that suggest the material weight at which opportunity sales influences the analysis.[8] Heavy dependence on market revenues to support a regulated investment choice is a speculative influence that we find must be materially discounted to limit the risk of customers being saddled with

[8] The submitted table indicates that the advantage of the Preferred Portfolio in comparison to (1) BAU to Gas Conversion escalates from 1.3% to 3.5% when the opportunity sales sharing moves from 50% to 100%.

uneconomic options should such speculation unfold differently than forecasted. A metric biased in favor of portfolios with surplus generation is speculation we decline to embrace.

Vectren South's own witnesses and others acknowledged risks related to relying on gas generation, but Vectren South only considered carbon dioxide emission reductions when it evaluated environmental risk. We agree that was too narrow an approach to environmental risk and one that biased the analysis in favor of gas-fired generation.

The Commission appreciates the metrics developed and used by Vectren South in the 2016 IRP, but we agree with the Joint Intervenors that the use of these particular metrics also obscured critical characteristics of the preferred portfolio. One of Vectren South's IRP objectives was to develop a plan with flexibility to adapt to market conditions and technological change to minimize risks to shareholders and customers. Specific metrics to measure resource portfolio balance and flexibility included concentration on one technology, the number of technologies and having resources remote from Vectren South's load. A critical piece of information these metrics overlook is that the acquisition of an 850 MW resource must be evaluated relative to the load to be served. Vectren South's 2016 IRP Base peak load forecast is for the summer peak to increase from 1,109 MW in 2019 to 1,198 MW in 2036. The acquisition of an 850 MW generation facility represents approximately 77 percent of the 2019 peak load and just under 71 percent of the summer peak load for 2036. We are hard pressed to see how reliance on one facility for so much of the Vectren South system requirements is consistent with maintaining flexibility to respond to changing market conditions and technological change.

Therefore, we conclude that Vectren South's risk analysis does not adequately consider the relative risk of other methods for providing reliable, efficient, and economical electric service. The proposed large scale single resource investment for a utility of Vectren South's size does not present an outcome which reasonably minimizes the potential risk that customers could sometime in the future be saddled with an uneconomic investment or serve to foster utility and customer flexibility in an environment of rapid technological innovation. As a result, we find that Vectren South has not demonstrated through the evidence of record that the public convenience and necessity require the building of an 850 MW CCGT. Therefore, Vectren South's request for a CPCN to construct a 850 MW CCGT is denied.

B. Vectren South's Request for a CPCN for Culley compliance projects and related relief. Vectren South's preferred portfolio also includes the construction of various environmental projects that Vectren South contends are needed so that Culley Unit 3 can continue to operate beyond 2023. Vectren South's petition seeks relief for these projects under Ind. Code ch. 8-1-8.4 as "federally mandated" projects.

i. Ind. Code ch. § 8-1-8.4 ("Chapter 8.4").

(1) Federally Mandated Requirements (Ind. Code §§ 8-1-8.4-5 and 8-1-8.4-6(b)(1)(A) and 8-1-8.4-7(b)(3)). Ind. Code § 8-1-8.4-5 defines a federally mandated requirement to include "a requirement that the commission determines is imposed on an energy utility by the federal government in connection with any of the following: (2) The federal Water Pollution Control Act (33 U.S.C. 1251 *et seq.*)" and also includes "(7) Any other law, order, or regulation administered or issued by the United States Environmental Protection Agency, the United States

Department of Transportation, the Federal Energy Regulatory Commission, or the United States Department of Energy."

The description of the Culley 3 Compliance Projects was set forth in the direct testimonies of Ms. Fischer and Ms. Retherford. The Culley 3 Compliance Projects consist of (1) conversion of the current wet bottom ash collection system to a dry handling bottom ash system; (2) installation of a spray dryer evaporator system; and (3) the closure of the Culley West ash pond and construction of a new lined process water and storm water retention pond in its place. This new retention pond will be constructed on the location of the existing ash pond due to space limitations. No party disputed that the dry handling bottom ash conversion or spray dryer evaporator system qualify as compliance projects to meet federally mandated requirements. The OUCC challenged whether the closure of the existing pond qualified for relief but did not contend that it was not federally mandated. For the reasons described below, we find that these projects all constitute compliance projects to meet federally mandated requirements as those terms are defined in Ind. Code §§ 8-1-8.4-2 and -5.

Vectren South witness Retherford testified that the dry handling bottom ash system is required to comply with the ELG Rule, which was promulgated under the federal Water Pollution Control Act. Petitioner's Exhibit No. 9, p. 11. The ELG rule prohibits further wet handling of fly and bottom ash. This system will enable ash from Culley Unit 3 to be disposed of in a landfill, hauled back to a surface mine in accordance with applicable surface mining regulation or recycled rather than being washed into the ash pond as part of a water discharge.

Ms. Retherford further explained that the spray dryer evaporator system was necessary to ensure compliance with ELG-imposed limits on FGD wastewater discharge. She noted that this system functions effectively as a ZLD system and enables Vectren South to utilize the alternative ELG-imposed compliance date of December 31, 2023, and to meet future more stringent ELG wastewater discharge limits.

Ms. Retherford testified that construction of a new, lined process and storm water retention pond is required to comply with the ELG Rule. As we have already noted, projects necessary to comply with the ELG Rule, promulgated pursuant to the federal Water Pollution Control Act (33 U.S.C. 1251 *et seq.*), constitute a federally mandated requirement. The only dispute, raised by OUCC witness Aguilar, pertains to Vectren South's plans to close the existing Culley West pond so that the new lined pond can be built at the site. Witness Retherford testified that there are two reasons the Culley West pond is closing: (1) the pond was taken out of service prior to the 2015 deadline and the CCR rule requires that it be closed by 2020; and (2) the current space limitations require that the new stormwater retention and process water pond be constructed on the current location. Thus, there is no dispute that costs associated with the construction of the new lined pond are incurred pursuant to a federally mandated requirement. The dispute is whether the costs to close the Culley West pond so that the new pond can be built on top of that location, also qualify as federally mandated costs.

The OUCC identifies three reasons closure costs for the Culley West pond should not be considered federally mandated costs. First, OUCC witness Aguilar contends that Vectren South has been collecting depreciation and asset retirement costs in base rates, which include the closure of ash ponds. Public's Exhibit No. 1, p. 28. However, Vectren South witness Retherford responded that finalization of the CCR rule on April 17, 2015 imposed more stringent requirements to close the ash pond. The CCR rule imposed an obligation to dewater, cap and/or remove ponded ash. Petitioner's Exhibit No. 9-R, pp. 24-25.

On rebuttal, Mr. Swiz stated Vectren South's existing depreciation rates include an estimated level of cost of removal that was designed well before the implementation of requirements to close the ponds in accordance with the environmental regulations described by Ms. Retherford. The assumed removal costs in the demolition study provided in Cause No. 43839 (Vectren South's most recent general rate case), estimated $1.1 million to close both of the Culley Ash Ponds based on cost of backfill, grading and seeding. By comparison, the estimate for closure of one ash pond in this proceeding is $19.969 million. Petitioner's Exhibit No. 13-R, pp. 6-7; Petitioner's Administrative Notice 1.

Consequently, we find that costs associated with CCR closure have not been included in Vectren South's depreciation rates, which were last updated prior to finalization of the CCR Rule.

Second, the OUCC contends that other utilities are not tracking pond closure costs as Federally-Mandated CCR Projects. Public's Exhibit No. 1, p. 28. Vectren South witness Swiz noted that no utility had proposed such recovery yet but that one utility specifically indicated that it would present closure related activities as recoverable under the Federal Mandate Statute. Petitioner's Exhibit No. 13-R, pp. 6-7. Mr. Swiz explained that Duke, IPL and NIPSCO did not ask for recovery of their pond closure costs in the proceedings Ms. Aguilar cited, and in fact the order in Cause No. 44765 specifically notes that Duke anticipates presenting closure related activities of existing surface impoundments and their associated costs in a future proceeding. Petitioner's Exhibit No. 13-R, p. 6, citing *Duke Energy Indiana*, Cause No. 44765, at *7 (IURC May 24, 2017). Each of the cases Ms. Aguilar cited were settled cases containing non-precedential language. Nevertheless, Mr. Swiz pointed out that the NIPSCO Order in Cause No. 44872, suggests that the OUCC agreed that closure costs can be recovered as federally mandated costs. Petitioner's Exhibit No. 13-R, p. 7.

Third, the OUCC contends that Vectren South should have presented alternative suitable locations to the West Pond for consideration. However, Ms. Retherford testified that the location was chosen because there was limited space at the Culley generating station. In other words, there was not an alternate location to explore. The statutory requirement to consider options does not require a utility to present alternatives that are not practical or feasible. Accordingly, we find the Culley 3 Compliance Projects are all federally mandated requirements and that Vectren South described them in its application.

(2) <u>Energy utilities seeking recovery of Federally Mandated Costs must establish that the costs are incurred in connection with a compliance project, including capital, operating, maintenance, depreciation, tax or financing costs and describe the costs to be recovered.</u> Ind. Code §§ 8-1-8.4-4 and -6(b)(1)(B). We have already found that the Culley 3 Compliance Projects constitute projects required by federally mandated requirements. Consequently, the costs associated with these projects constitute Federally Mandated Costs. These costs will consist of capital, operating, maintenance, depreciation, tax and financing costs. Vectren South identified the estimated costs to be recovered as Federally Mandated Costs. Costs associated with the dry handling bottom ash handling system and spray dryer evaporator system were identified by Vectren South witness Fischer. Petitioner's Exhibit No. 6, pp. 16-18, 26-28. Costs associated with the construction of a new lined process water and storm water retention pond were identified in Ms. Retherford's testimony. Petitioner's Exhibit No. 9, Attachment AMR-1. No party disputed the cost estimates for the Culley 3 Compliance Projects. Based on the evidence presented, we find that Vectren South has identified

federally mandated costs and reasonably described those costs. Those total costs are $95 million, and they are hereby approved. Petitioner's Exhibit No. 4, p. 26.

(3) Compliance with Federally Mandated Requirements (Ind. Code §§ 8-1-8.4-6(b)(1)(C)) and 8-1-8.4-7(b)(3)). No party disputed that the Culley 3 Compliance Projects will allow Vectren South to comply with ELG and CCR or that ELG and CCR are federally mandated. We previously addressed the OUCC's objections related to appropriateness of recovery. We have already found that the ELGs and CCR Rule are federally mandated requirements within the meaning of Ind. Code §§ 8-1-8.4-5 and 8-1-8.4-6(b)(1)(A) and 8-1-8.4-7(b)(3). Based on the evidence presented, we find that Vectren South's Culley 3 Compliance Projects, will allow the utility to comply with the ELGs and the CCR Rule. Therefore, we find that Vectren South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(C).

(4) Alternative Plans for Compliance (Ind. Code §§ 8-1-8.4-6(b)(1)(D) and 8-1-8.4-7(b)(3)). Ind. Code § 8-1-8.4-6(b)(1)(D) requires the Commission to examine "[a]lternative plan that demonstrate that the proposed compliance project is reasonable and necessary." Vectren South witness Diane Fischer testified about Black & Veatch's evaluation of the ELG Compliance Program for Culley to identify potential FGD discharge water treatment alternatives and ash transport water alternatives that could be implemented to comply with the ELGs. She sponsored two written reports setting forth Black & Veatch's analyses of the alternatives. Ms. Fischer testified that each of the potential discharge treatment technology alternatives assessed by Black & Veatch were screened for design concept feasibility, capital expense and operating expense.

With respect to FGD discharge water treatment, two main treatment alternatives were considered: (1) FGD treatment and discharge; and (2) zero liquid discharge ("ZLD"). Three technology types were evaluated within these two treatment alternatives: (1) for FGD treatment and discharge, physical/chemical pretreatment with biological treatment technology, (2) for ZLD, spray dryer evaporator technology, and (3) also for ZLD, brine concentrator/crystallizer technology. Ms. Fischer testified that multiple vendors providing such technologies were evaluated. A sensitivity analysis was then performed for each technology and vendor. Ms. Fischer's Discharge Treatment Report also included a cost assessment of all alternatives considered. Petitioner's Exhibit No. 10, p. 7. Ms. Fischer testified that Black & Veatch provided Vectren South with a final overall assessment of each technology and vendor offering based on Black & Veatch's analysis and the following attributes: (1) start-up/ramp up reliability; (2) technology readiness risk; (3) adaptability to sensitivity analysis scenarios; (4) operation and control risk; (5) heat rate impact risk; (6) number of operators; (7) capital and annual O&M costs; (8) susceptibility to future environmental regulations; (9) overall financial stability and credit rating. Black & Veatch ultimately recommended that Vectren move forward to a detailed engineering phase with Stochastic Differential Equation ("SDE") type technology if the maximum FGD wastewater flow rate of between 50 and 80 gpm is achieved through future testing and operations. Ms. Fischer explained the SDE solution ranks the highest among all technologies based on the attributes discussed above and the solution is economically viable and provides a zero discharge solution if the minimum FGD wastewater flow rate of between 50 and 80 gpm is achieved. The conceptual design evaluation indicated the SDE can be feasibly located and tied into the existing equipment at Culley. In addition, Ms. Fischer stated the ZLD solution provides certainty that any future change in EPA regulations would not apply at Culley since there would be no discharge of FGD wastewater.

With respect to ash transport, Ms. Fischer described Black & Veatch's analysis to identify alternative ash transport solutions that could be implemented at Culley to comply with ELG requirements, focused specifically on identifying options for removal and dewatering of bottom ash from the Culley Unit 3 boiler with truck transport and disposal of the dry material at an off-site location. Black & Veatch evaluated two categories of technologies: (1) dry conversion of the bottom ash system and (2) closed loop wet sluicing system. For dry conversion system, Black & Veatch evaluated a submerged chain conveyor under the existing bottom ash hopper. For the closed loop wet sluicing system, Black & Veatch evaluated both a dewatering bunker and a remote submerged chain conveyor. In comparing all technologies, Black & Veatch used the following quality attributes to select the preferred treatment: technical feasibility; total installed cost, O&M cost, estimated additional manpower ("FTE"), estimated footprint, major equipment, advantage, disadvantages and reliability. Ms. Fischer's testimony discussed in detail the advantages and disadvantage of each alternative. Black & Veatch prepared cost estimates for all technologies considered for addressing ash transport water. Black & Veatch ultimately recommended the submerged chain conveyor for Culley 3 compliance with ELG requirements, due to the complexity of design and comparatively higher installed cost of the other alternatives.

The only evidence offered in opposition as being an alternative plan was the OUCC's conclusory statement about possible alternative locations for the new lined pond. As we have previously found, the chosen site was selected because there are no alternative locations.

While the Commission gives significant weight to cost-effective planning and decision making when considering alternatives, the Federal Mandate Statute does not require that a utility demonstrate that the chosen compliance plan is the least cost option. Consistent with the Commission's finding in Indianapolis Power and Light's recent proceeding, Cause No. 44794 (IURC 4/26/2017), p. 30, 2017 Ind. PUC LEXIS 114, *92, (finding "it is important that the Petersburg Station is able to continue to operate on coal and protect customers from potential price volatility in the gas markets"), a reasonable alternative can be, and often is, a solution that includes risk balancing through a diversified portfolio.

Based on the evidence presented, we find that Vectren South considered alternative plans for compliance with the ELGs and the CCR Rule. The evidence shows that the Culley 3 Compliance Projects are reasonable and necessary.

(5) Useful Life of the Facility (Ind. Code §§ 8-1-8.4-6(b)(1)(E) and 8-1-8.4-7(b)(3)). Mr. Games testified that the investments in the Culley 3 Compliance Projects will allow for the continued operation of Vectren South's most efficient coal fired unit. Ms. Retherford described the environmental regulations requiring the Culley 3 Compliance Projects in order for Culley Unit 3 to continue operating. Ms. Retherford explained how closure of the Culley West pond will extend the useful life of Culley 3, because closure of the Culley West pond is necessary to provide a suitable location to construct a new pond that can continue to take non-CCR process water discharged from Culley Unit 3 and plant stormwater (i.e. surface water) which flows into the West Pond. Without this new lined process and stormwater pond, continued operation consistent with applicable regulations would be impossible after the Culley East pond commences closure.

No party disputes that issuance of a CPCN for the Culley 3 Compliance Projects will extend the useful life of Vectren South's Culley 3 unit or that Culley 3 would be required to retire in the near future if the Culley 3 Compliance Projects are not completed.

Based on the evidence presented, we find that Vectren South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(E).

(6) Conclusion. We find that the Culley 3 Compliance Projects will allow Vectren South to comply directly or indirectly with one or more federally mandated requirements and that public convenience and necessity will be served by the Culley 3 Compliance Projects.

ii. Accounting and Ratemaking Issues Associated with Culley Compliance Projects. Ind. Code § 8-1-8.4-7(c) states:

> If the commission approves under subsection (b) a proposed compliance project and the projected federally mandated costs associated with the proposed compliance project, the following apply:
> (1) Eighty percent (80%) of the approved federally mandated costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs. The Commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for purposes of IC 8-1-2-42(d)(3)and IC 8-1-2-42(g)(3).
> (2) Twenty percent (20%) of the approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission.
> (3) Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by the energy utility with the commission.

(1) Accounting and Ratemaking Treatment for ECA. Vectren South requests authority to implement a new annual rate adjustment mechanism ("ECA") pursuant to Ind. Code § 8-1-8.4-7 for the timely and periodic recovery of 80% of the federally mandated costs. Vectren South also requests approval of proposed changes to its electric service tariff relating to the proposed ECA mechanism, including the proposed Appendix E. Ind. Code §8-1-8.4-8 provides that an energy utility may, in a timely manner, recover 80% of all federally mandated costs through a periodic rate adjustment mechanism. Ind. Code §§ 8-1-8.4-4 and 8-1-8.4-7 provide that such costs include capital, AFUDC, O&M, depreciation, tax, and financing costs.

Vectren South witness Swiz described how the eligible costs associated with the Culley 3 Compliance Projects will be incorporated into the proposed ECA mechanism. He testified Vectren South will prepare in each annual filing a revenue requirement calculation accumulating all eligible costs incurred through December 31 of the previous calendar year. To provide for timely recovery, Mr. Swiz testified the proposed ECA will project an annualized level of expense related to the approved projects for the 12-month effective period. Mr. Swiz stated the annual revenue requirements will capture eligible new capital investments (both in service and Construction Work in Progress) related to the Culley 3 Compliance Projects, multiplied by the applicable rate of return, with depreciation, O&M and property tax expenses associated with the projects, and recovery of the regulatory assets recorded through interim deferral of depreciation expense, plan development expense, and PISCC, added to the resulting total. The revenue requirement for those projects will be the basis for the recovery of 80% of the eligible revenue requirement amounts in each annual ECA filing.

Mr. Swiz also described Vectren South's proposal to defer and subsequently recover depreciation expense as well as costs associated with development of the Culley 3 Compliance Projects through the ECA. The cumulative deferred balances of the regulatory assets recorded through interim deferral of such depreciation expenses would be amortized over the remaining life of the assets (20 years) and the amortization amount would be included in the ECA revenue requirements. Mr. Swiz stated the costs of development of the projects would be included for recovery within the ECA, with the balance amortized over a period of three years.

Vectren South proposes the pre-tax return on the new capital investment will be calculated by multiplying the pre-tax rate of return, based on the weighted average cost of capital ("WACC"), by total new capital investment related to the approved projects. Mr. Swiz testified Vectren South proposes to use a WACC in the ECA based upon the most recent approved WACC within Vectren South's TDSIC mechanism under Cause No. 44910, which is based on a return on equity ("ROE") of 10.4% as approved in Cause Nos. 43111 and 43839, Vectren South's two most recent base rate cases. Mr. Swiz stated the equity component of the rate used in the ECA revenue requirement calculation will be grossed up for recovery of income taxes, both state and federal, at then current rates.

Mr. Swiz testified that approved recoveries within each ECA filing will be calculated by taking the billing determinants by month multiplied by the applicable rates and charges for the ECA period. Any under recoveries resulting from instances in which ECA rates and charges are not in place for a full month will be recovered as an under-recovery variance in a subsequent ECA proceeding. Vectren South proposes to allocate ECA costs pursuant to the four-coincident peak allocation percentages for Vectren South utilized in its Cause No. 43406 RCRA15 and 43405 DSMA15 rate mechanisms.

With respect to the treatment of operating income, Mr. Swiz testified Vectren South will adjust its statutory earnings test under Ind. Code § 8-1-2-42(d)(3) to include the incremental earnings from approved ECA filings.

Mr. Swiz testified Vectren South proposes to file its ECA petitions and cases in chief annually, on May 1 of each year, with new ECA rates and charges becoming effective August 1 of each year. Each filing will be based on capital investments and expenses through the twelve months ended December of the prior calendar year. Variances will be reconciled in each ECA filing and recovered over the subsequent 12 month rate effective period. Vectren South seeks approval of its proposed Sheet No. 69, Appendix E, Environmental Cost Adjustment. Additional changes to Vectren South's rate schedules in its tariff are needed to reflect that the ECA will be applied monthly.

Industrial Group witness Gorman recommended that the ELG costs associated with the Culley 3 Compliance Projects be recovered within a base rate proceeding and not through the proposed ECA. He cited Vectren South's overall rate of return and stated Vectren South's costs have declined since the last base rate case. He also suggested that Vectren South should be permitted to recover a return on investment of no more than 9.8%.

Mr. Swiz explained on rebuttal that under the statutory test under Ind. Code § 8-1-2-42(d) and -42.3, performed in Vectren South's most recent FAC proceedings as of the time his rebuttal testimony was filed (Cause No. 38708 FAC 120), Vectren South's comprehensive earnings compared to authorized levels, including both changes in expenses and revenues, show that Vectren South is currently under-earning by approximately $6.5 million of net operating income and has been under-earning since February 2017. Mr. Swiz explained that depreciation and operating expense are driving much of these results, and Mr. Gorman does not capture those expenses in his calculation.

Eligibility for recovery through Ind. Code ch. 8-1-8.4 is not contingent on whether other costs have declined to offset the new federally mandated costs. Once we have made the required findings, 80% of the federally mandated costs "shall be recovered by the energy utility through a periodic retail rate adjustment mechanism." Ind. Code § 8-1-8.4-7(c)(1). In any event, we find that Mr. Swiz has adequately explained why Mr. Gorman's position is incorrect.

Mr. Swiz testified that pursuant to Ind. Code § 8-1-8.4-7, Vectren South seeks ratemaking treatment for 80% of the costs associated with the Culley 3 Compliance Projects through its proposed ECA mechanism. Specifically, Vectren South seeks timely recovery of all federally mandated costs associated with the Culley 3 Compliance Projects, including capital costs, AFUDC, post-in-service carrying cost charges ("PISCC"), O&M, depreciation expense, property tax expense, and other taxes, with 80% recovered through the ECA and the balance deferred for recovery in Vectren South's next rate case.

Vectren South proposes to implement construction work in progress ("CWIP") ratemaking treatment related to the recovery of financing costs incurred during construction of the Culley 3 Compliance Projects. In connection with CWIP ratemaking treatment, Vectren South will remove from the AFUDC-eligible balance the amount of investment included for recovery in the ECA, so that only the amount of the Culley 3 Compliance Projects investment not currently being recovered in the ECA would be eligible for AFUDC.

Mr. Swiz testified that Vectren South proposes to accrue post-in-service carrying charges on all eligible new capital investment from the date it is placed in service until the date it is included in rates. He explained the PISCC balances will be multiplied by the pre-tax rate of return within the ECA revenue requirement, at the WACC rate described herein. Unlike other utilities who have been granted such authority, Vectren South is not seeking to accrue and subsequently recover in the next base rate case PISCC on the 20% deferred balance discussed below.

OUCC witness Aguilar opposed Vectren South's request to recover pond closure costs for the Culley 3 Compliance Projects as part of the ECA because the OUCC's position is that Vectren South is already collecting pond closure costs within its depreciation rates. Ms. Aguilar also testified that neither Duke, IPL, nor NIPSCO are tracking pond closure costs. We have already addressed these positions and rejected them.

Based on the evidence presented, we find that the proposed ECA mechanism should allow for the timely and periodic recovery of 80% of Vectren South's approved federally mandated costs. We further find that Vectren South's request for approval to adjust its authorized net operating income to reflect an approved earnings associated with the Culley 3 Compliance Project for purposes of Ind. Code §§ 8-1-2-42(d)(3) and 8-1-2-42(g)(3) is consistent with Ind. Code § 8-1-8.4-7(c)(1).

Vectren South is authorized to defer (until captured within the ECA mechanism) and recover 80% of the approved federally mandated costs incurred in connection with the Culley 3 Compliance Projects through the approved ECA Mechanism pursuant to Ind. Code § 8-1-8.4-7, including capital, O&M, depreciation, taxes, financing, and carrying costs based on the current overall WACC and AFUDC. Vectren South is authorized to utilize CWIP ratemaking treatment for the Culley 3 Compliance Projects through the proposed ECA mechanism. Vectren South is authorized to defer post-in service costs of the Culley 3 Compliance Projects, including carrying costs based on the current overall WACC, depreciation, taxes and operating and maintenance expenses on an interim basis until such costs are recognized for ratemaking purposes through Vectren South's ECA mechanism or otherwise included for recovery in Vectren South's base rates in its next general rate case. Vectren South is authorized to defer and recover through the ECA mechanism 80% of its federally mandated costs, including but not limited to federally mandated costs incurred prior to and after approval of a final order in this proceeding to the extent that such costs are reasonable and consistent with the scope of the Culley 3 Compliance Projects described in Vectren South's evidence. Vectren South's proposed cost allocation factors are also approved.

(2) Accounting and Ratemaking Treatment for Deferred Costs. Indiana Code § 8-1-8.4-8 provides that 20% of the approved federally mandated costs, including depreciation, AFUDC, and PISCC, based on the overall cost of capital most recently approved by the Commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the Commission. Vectren South proposes to defer as a regulatory asset 20% of all federally mandated costs incurred in connection with these projects.

Based on the evidence presented, the Commission finds Vectren South is authorized to defer 20% of the federally mandated costs incurred in connection with the Culley 3 Compliance Projects, and Vectren South may recover the deferred costs in its next general rate case as allowed by Ind. Code § 8-1-8.4-7(c)(2).

(3) Depreciation Treatment. Vectren South proposes to utilize a depreciation rate of 5%, representing a 20-year life on these investments. Mr. Swiz testified the proposed depreciation rate for the investments aligns with the estimated remaining life of Culley Unit 3.

No party opposed Vectren South's proposed depreciation rate for the investments required for the Culley 3 Compliance Projects.

Based on the evidence presented, we find that Vectren South's proposal to depreciate the individual projects included in the Culley 3 Compliance Projects based on a 5% depreciation rate is reasonable and is approved.

C. **Recovery of Prior Pollution Control Investments.** Our January 28, 2015 and June 22, 2016 Orders in Cause No. 44446 (the "44446 Orders") (1) granted Vectren South a CPCN for A.B. Brown Unit 1 and 2, Culley Unit 3 and Warrick Unit 3 clean coal technology projects and (2) authorized Vectren South to recover federally mandated costs associated with federally mandated requirements at A.B. Brown Units 1 and 2 (collectively the "MATS Projects"). Rather than recovering the costs of the MATS Projects through a tracking mechanism as authorized by Ind. Code § 8-1-8.4-7, Vectren South sought, and we granted, authority to defer these costs for recovery in a future proceeding. Vectren South now seeks to commence recovery of the MATS Projects' costs through the ECA pursuant to Ind. Code § 8-1-8.4-7.

Vectren South witness Swiz described the proposed recovery through the ECA in more detail. He indicated that Vectren South proposes recovery of the MATS Projects to begin on January 1, 2019 with the approval of ECA rates and charges recovering the specified revenue requirement. In accordance with applicable statutory requirements, Vectren South proposes to recover the 80% of eligible revenue requirements amounts for post-in-service carrying costs, incremental depreciation and property taxes and financing costs that Vectren South incurred to construct the MATS Projects and deferral of the remaining 20% of these costs for subsequent recovery in a base rate case. Vectren South will prepare an annual revenue requirement as part of the ECA to capture eligible capital investments in plant related to the MATS Projects, multiplied by the applicable rate of return, with depreciation, O&M, and property tax expenses associated with the MATS Projects added to the resulting total. To provide for timely recovery, Vectren South's proposed ECA will project an annualized level of expense related to these approved projects for the 12-month effective period.

Depreciation associated with the MATS Projects will be based on the currently approved depreciation rates applicable to the assets, as approved in Vectren South's last electric base rate case (Cause No. 43839). The pre-tax return on the new capital investment will be calculated by multiplying the pre-tax rate of return, based on the WACC, by total new capital investment related to the approved projects. Vectren South proposes to use a WACC in the ECA based upon the most recent approved WACC within Vectren South's TDSIC mechanism, Cause No. 44910. This WACC, approved by the Commission, represents an updated actual capital structure as of the cut-off date of each TDSIC filing, and includes the typical items captured in Vectren South's base rate case capital structure. This rate will be used in the ECA revenue requirement calculation, and the equity component will be grossed up for recovery of income taxes, both state and federal, at then current rates. O&M expense included for recovery in the ECA will reflect an annualized level of expense related to the MATS Projects. This O&M expense represents incremental chemical costs and other expenses associated only with the MATS Projects.

No party objected to Vectren South's proposal to commence recovery of the MATS Projects' costs, currently being deferred, through the ECA. We previously found the MATS Projects costs qualify as federally mandated costs in the 44446 Orders. While Vectren South proposed, and we approved of, deferral of these costs in lieu of the recovery through a periodic retail rate adjustment mechanism, Vectren South now seeks to recover the costs in accordance with Ind. Code § 8-1-8.4-7(c). We find that Vectren South shall be authorized to commence recovery of these MATS Projects' costs pursuant to Ind. Code § 8-1-8.4-7 through the ECA in accordance with the procedures outlined in Mr. Swiz's testimony.

6. **Confidentiality.** Vectren South filed motions for protection and nondisclosure of confidential and proprietary information on March 20, 2018, August 21, 2018, and September 10, 2018, respectively. In its motions, Vectren South states certain information redacted in the evidence is confidential, proprietary, competitively sensitive, and/or trade secrets. Docket entries were issued on March 29, August 27, and October 4, 2018 finding such information to be preliminarily confidential and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. The confidential information was subsequently submitted under seal. The Commission finds the

information for which Vectren South seeks confidential treatment is confidential trade secret information pursuant to Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

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

1. Vectren South's request for a certificate of public convenience and necessity under Ind. Code ch. 8-1- 8.5 to construct an 850 MW CCGT and all associated relief requested is denied.

2. Vectren South's request for a certificate of public convenience and necessity for the Culley 3 Compliance Projects pursuant to Ind. Code ch. 8-1-8.4 and all associated relief requested is approved.

3. Vectren South's proposed recovery of federally mandated costs approved in connection with Cause No. 44446 through the ECA is approved as described in this Order.

4. Vectren South's proposed ECA, and Vectren South's proposed Sheet No. 69, Appendix E of its tariff to implement such ECA is approved.

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

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

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

APPROVED: APR 24 2019

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

Mary M. Becerra

Mary M. Becerra
Secretary of the Commission

Ex. AA-S-4

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NEWS RELEASE

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Hoosier Energy Announces New 20-Year Resource Plan

For Immediate Release - Bloomington, Ind. (Jan. 21, 2020) – Following a year-long process, Hoosier Energy today announced that its Board of Directors approved a new long-range resource plan. The current plan is designed to provide its 18 member cooperatives with reliable, affordable and environmentally sustainable energy while saving members an estimated $700 million over the next two decades.

Hoosier Energy expects to retire its coal-fired Merom Generating Station in 2023 and transition to a more diverse generation mix that includes a combination of low-cost wind, solar, natural gas and storage. This plan provides a foundation for supply cost stability and predictability while reducing the company's carbon footprint by nearly 80%.

Approximately 185 cooperative employees currently support operations of the 1,070-megawatt Merom Station, which is in Sullivan, IN, and went online in 1982. Hoosier Energy President & CEO Donna Walker said, "We sincerely value our dedicated employees and will help those impacted during this transition by working with the IBEW to offer assistance such as retraining, reassignment and professional outplacement, along with retirement options."

There are several possibilities regarding the future of the site. Hoosier Energy will work with state and local economic development officials to market portions of the Merom property for industrial development. The company will also consider renewable energy generation at the location or pursue a sale of the plant.

About Hoosier Energy
Hoosier Energy is a generation and transmission cooperative (G&T) with headquarters in Bloomington, Indiana. The G&T provides electric power and services to 18 electric distribution cooperatives in southern and central Indiana and southeastern Illinois. Collectively, the 18 members serve nearly 650,000 consumers. For more information, visit www.hoosierenergy.com.

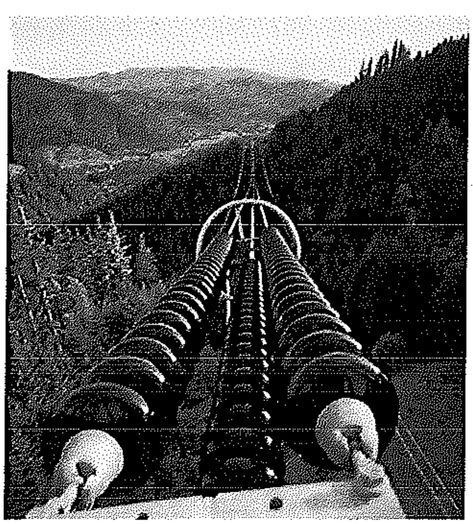
Hoosier Energy Rural Electric Cooperative is an equal opportunity employer.

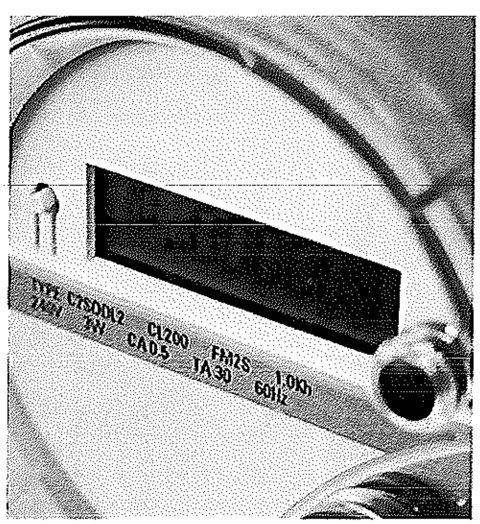
Ex. AA-S-5

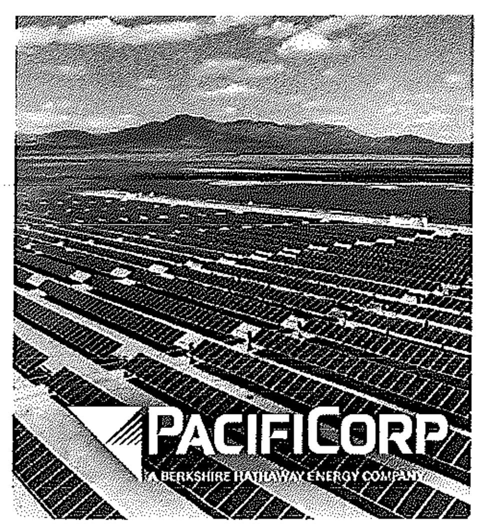
2019 Integrated resource plan

VOLUME I

OCTOBER 18, 2019







This 2019 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

For more information, contact:
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Cover Photos (Top to Bottom):
Marengo Wind Project
Transmission Line
Electric Meter
Pavant III Solar Plant

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CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp's 2019 Integrated Resource Plan (IRP) was developed through comprehensive analysis and a public-input process spanning nearly a year and a half resulting in the selection of a least-cost, least-risk preferred portfolio. The 2019 IRP preferred portfolio includes accelerated coal retirements and investment in transmission infrastructure that will facilitate adding over 6,400 megawatt (MW) of new renewable resources by the end of 2023, with nearly 11,000 MW of new renewable resources over the 20-year planning period through 2038.[1] The 2019 IRP preferred portfolio advances PacifiCorp's long-term vision as described in the following section.

PacifiCorp's Vision

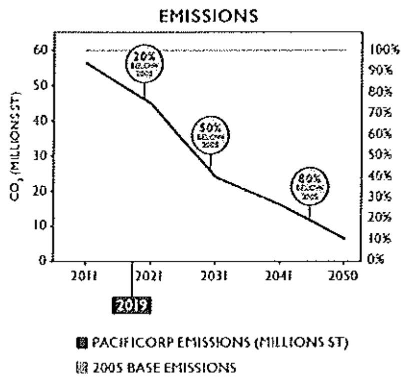
PacifiCorp shares a bold vision with our customers for a future where energy is delivered affordably, reliably and without greenhouse gas emissions. A future where our vast, modern energy grid connects local communities to the low-cost and reliable energy they need to innovate and achieve their goals. PacifiCorp believes that affordability and sustainability go hand in hand and together, they form the foundation for a reliable, resilient energy future—where regional and state economies benefit from investments in energy resources and infrastructure that help them pioneer new growth opportunities. It is an ambitious vision, but it is absolutely achievable. By connecting the West's diverse resources to the vast reach of our transmission system and by investing in technology, partnerships and markets, PacifiCorp is positioned to create the future our customers and communities seek.

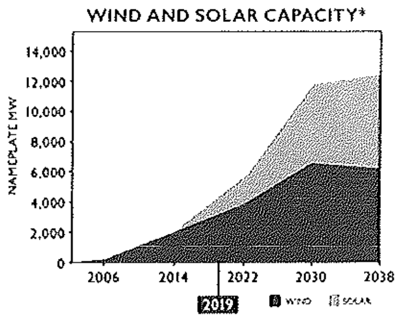
Reimagining the Future Based on a Century of Innovation

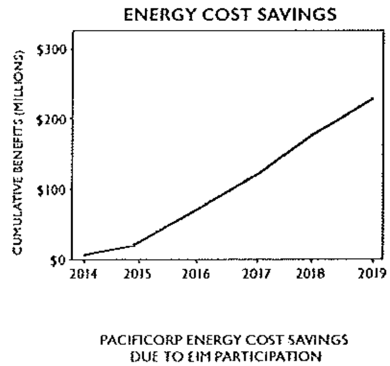
When PacifiCorp joined Berkshire Hathaway Energy in 2006, the company set out to be the best energy company in terms of service to its customers while delivering sustainable energy solutions. The path forward was viewed as an invitation to reimagine not just how energy is produced but how it is dispatched and delivered. It was clear that PacifiCorp's greatest opportunity would be discovered in understanding the needs and aspirations of its customers and communities. The company saw the West itself, with its abundance of diverse natural resources, as a way to deliver greater value. And believed that the greatest gains could be realized by building upon the more than 100 years of innovation that helped create PacifiCorp's ten-state energy grid. By drawing on its track record of partnership and technology-driven innovation, PacifiCorp could transform its expansive grid into an industry-leading, interconnected energy system—a system uniquely equipped to access the best energy resources the West has to offer and efficiently deliver those resources to customers and communities across the region.

PacifiCorp has made significant progress over the past 13 years, becoming the largest regulated utility owner of wind power in the West. From 2018 to 2020, PacifiCorp will have increased the percentage of zero-carbon energy resources in its portfolio by 70 percent. The company made sure to do it all while capturing and returning savings to its customers.[2]

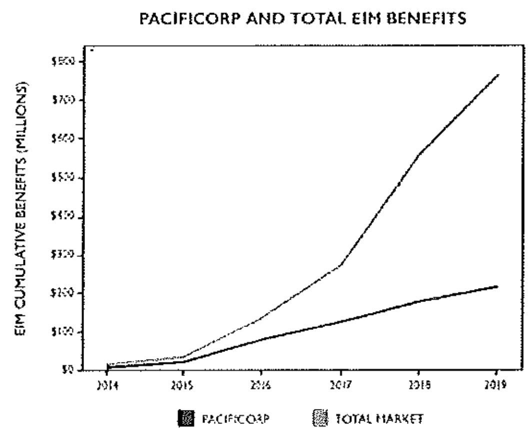
[1] Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.
[2] *Id.*







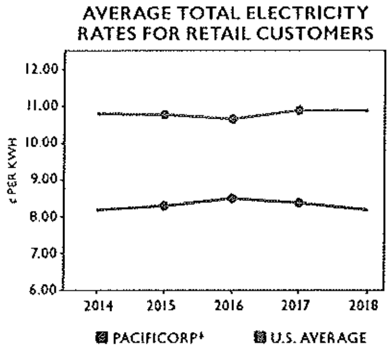
Reinventing the Future through Collaboration



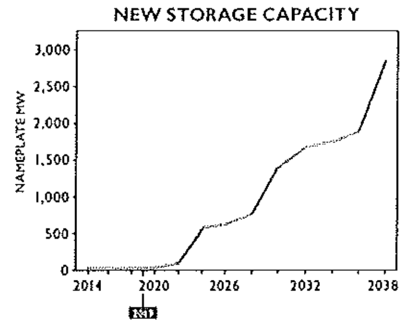
Over the past 13 years, PacifiCorp has successfully reduced its carbon emissions and improved reliability while simultaneously delivering energy cost savings to its customers. These results have been achieved by collaborating with others to create a more open and connected Western grid and through the visionary and collaborative efforts of PacifiCorp's own generation, transmission, information technology and energy supply management teams. In 2014, PacifiCorp pioneered the Western Energy Imbalance Market (EIM) in partnership with the California Independent System Operator. This innovative market allows utilities across the West to access the lowest-cost energy available in near real time, making it easy for zero fuel-cost renewable energy to go where it is needed. If excess solar energy in California, excess wind from Wyoming or hydropower from Washington and Oregon is available, PacifiCorp will harness it and transport it instantly across the company's 16,500-mile grid.

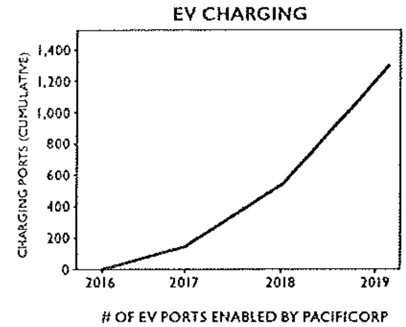
Through participation in the EIM, PacifiCorp has saved its customers over $200 million so far. The savings get bigger every year, and the company has reduced its portfolio carbon emissions over 15 million tons—the equivalent of taking 3 million cars off the road for a year.

Since its inception, nine utilities have joined the EIM and 11 more have committed to join by 2022, altogether representing almost 70 percent of the West's total electricity demand. As more participants join the EIM, the benefits increase. To date, participating utilities across the West have saved customers over $730 million while simultaneously decarbonizing the Western grid. PacifiCorp continues to engage new partners in evolving the real-time EIM to include a day-ahead market for even bigger future benefits.



Source: Edison Electric Institute Sales and Revenue Data for the 12 months ending December of each year





Rethinking the Future by Investing in the Diversity of the West

PacifiCorp continues to offer its customers some of the lowest energy prices in the country—well below the national average—while simultaneously expanding the depth and breadth of its energy portfolio and solutions.

- **Energy Vision 2020**: In 2017, PacifiCorp announced its largest historical investment in the development of renewable energy and infrastructure—Energy Vision 2020. This $3 billion project to be completed in 2020 embodies the company's commitment to a future that benefits its customers, its communities and the environment. It will dramatically increase PacifiCorp's renewable energy portfolio with new and repowered wind resources and new transmission while leveraging federal production tax incentives to provide hundreds of millions of dollars in savings to its customers over the life of the projects. Energy Vision 2020 also benefits rural communities across the West by creating hundreds of construction jobs and adding millions of dollars in construction tax revenue and ongoing annual state and local tax revenue.

- **Proposed New Resource Investments**: PacifiCorp's 2019 IRP sets forth a plan to expand its resource portfolio with new low-cost wind generation, solar generation and storage to meet changing customer needs.[3]

Resource	Through 2023	Through 2038
Wind (ID, UT, WA, WY)	Over 3,500 MW	Over 4,600 MW
Solar (ID, OR, UT, WA, WY)	Nearly 3,000 MW	Over 6,300 MW
Storage (ID, OR, UT, WA, WY)	Nearly 600 MW	Over 2,800 MW

Innovating Solutions to Build the Future

- **Demand Response**: PacifiCorp is championing technical innovations that use fast-acting residential demand response resources to support the bulk power system. PacifiCorp's approach moves beyond peak-load management to create a grid-scale solution that turns demand response resources into frequency-responsive operating reserves. With over 92,000 customers participating in this program, more than 200 MW of operating reserve is available every day and can be dispatched in a matter of seconds. This reduces PacifiCorp's

[3] *Id.*

need to supply operating reserves with higher cost alternatives, and it is only used in emergencies, minimizing inconvenience to customers.

PacifiCorp is also partnering with The Wasatch Group to develop and manage a first-of-its-kind residential battery demand response solution. This new all-electric apartment building in Utah features on-site energy storage for each of its 600 units, totaling 12.6 MWh of solar-powered battery storage. This innovative all-electric design provides emergency back-up power to residents, helps address air quality issues in the area and benefits overall electric grid operation.

- **Customized Renewable Energy Solutions**: PacifiCorp is partnering with communities and customers across the West to champion customized energy solutions to achieve their renewable energy goals. For example, the company's work with Facebook is resulting in the construction of 677 MW of new solar and wind capacity, all in service by the end of 2020. These projects support Facebook's operations in Oregon, enabling it to achieve its 100% renewable goal while simultaneously lowering energy supply costs for all PacifiCorp customers. In addition, PacifiCorp secured 122 MW of new solar energy capacity on behalf of Facebook's data center in Eagle Mountain, Utah.

- **Electrification**: The electric transportation market is in an emerging state that represents a potential driver for future load growth, improved air quality, reduced greenhouse gas emissions, improved public health and safety, and creation of financial benefits for drivers, particularly for low and moderate-income populations. PacifiCorp is investing over $26 million to support electric vehicle (EV) fast chargers along key corridors, develop robust workplace charging programs, implement smart mobility programs and develop opportunities for customers in its rural communities. The company's investments include a $4 million partnership award from the U.S. Department of Energy to research and develop electric transportation primarily in Utah and $3 million as part of the Oregon Clean Fuels Program.

Bringing the Best of the West to PacifiCorp's Customers

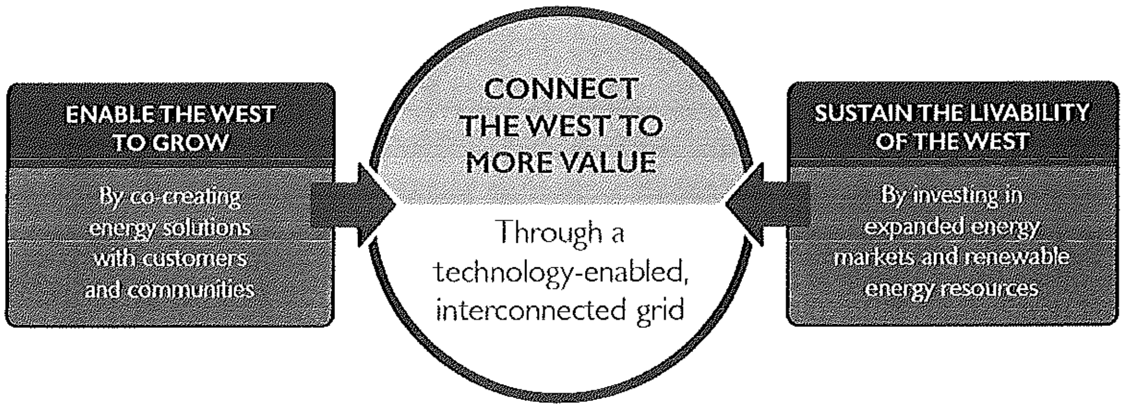
PacifiCorp's 2019 IRP includes investments in diverse new resources like, renewables, storage and modern grid technology among them. It outlines new transmission infrastructure investments across our territory that are needed to remove existing transmission constraints and improve grid resilience so the lowest-cost renewable resources can flow freely to customers across the West.

PacifiCorp's IRP also provides the roadmap by which it will dramatically reduce its greenhouse gas emissions over the next 20 years. The IRP shows that, by 2030, PacifiCorp will have reduced greenhouse emissions by nearly 60 percent from 2005 levels. Along with adding renewables and leveraging new technology, emissions reductions will be achieved by the phased transition of its coal fleet.

PacifiCorp's thermal assets and operations teams have played an essential role in enabling the progress made to date, and the company recognizes the vital part that these resources play in their communities too. PacifiCorp is committed to open and transparent communication about our coal transition, and equally committed to working with our employees and communities to develop plans that help them through this time of change.

Connecting the West to More Value

PacifiCorp believes a path to reduced carbon emissions must be substantiated with a prescriptive and thoughtful plan. The company's plan revolves around three interrelated strategies to reimagine an energy future that serves all of its communities.



PacifiCorp sees the energy diversity of the West as a catalyst. The company's plans to meet the energy needs of its customers and communities across the West will continue to evolve, but PacifiCorp's commitment to making the West stronger and better is unwavering. PacifiCorp will achieve this by continuing to find answers in new partnerships, advanced technologies and expanded energy markets, and by pursuing energy solutions that harness and bring the best energy resources the West has to offer to its customers' door.

PacifiCorp's Integrated Resource Plan Approach

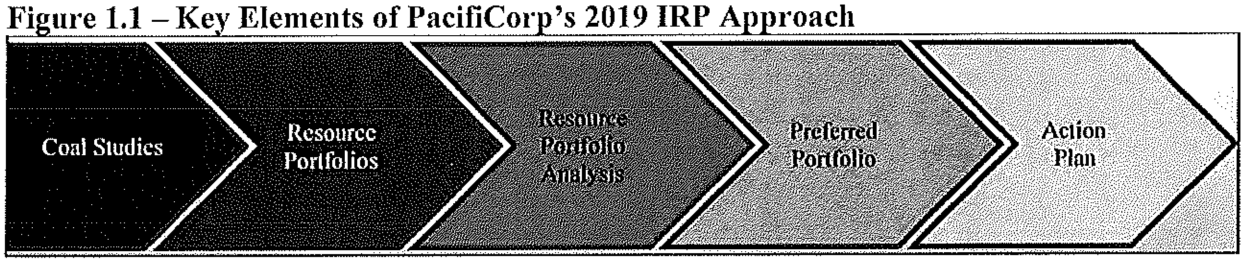
PacifiCorp has been making progress in its efforts to bring the best of the West to its customers, and PacifiCorp's 2019 IRP presents the company's plans to make significant advancements in this vision. The 2019 IRP sets forth a clear path to provide reliable and reasonably priced service to its customers. The analysis supporting this plan helps PacifiCorp, its customers, and its regulators understand the effect of both near-term and long-term resource decisions on customer bills, the reliability of electric service PacifiCorp customers receive, and changes to emissions from the generation sources used to serve customers. In the 2019 IRP, PacifiCorp presents a preferred portfolio that builds on its vision to deliver energy affordably, reliably and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity while maintaining substantial investment in energy efficiency programs.

The primary objective of the IRP is to identify the best mix of resources to serve customers in the future. The best mix of resources is identified through analysis that measures cost and risk. The least-cost, least-risk resource portfolio—defined as the "preferred portfolio"—is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks, while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

The full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly the longer-range elements, can and do change over time. PacifiCorp's 2019 IRP was developed through an open and extensive public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, community members, regulatory staff, and other interested parties. The public-input process began with the first public-input meeting in June 2018. Over the subsequent year and a half, PacifiCorp met with stakeholders in five states and hosted eighteen public-input meetings. Throughout this effort, PacifiCorp received valuable input from stakeholders and presented findings from a broad range of studies and technical analyses that shaped and informed the 2019 IRP.

As depicted in Figure 1.1, PacifiCorp's 2019 IRP was developed by working through five fundamental planning steps that began with a comprehensive and robust analysis of its coal units. The narrow scope of the coal study, which focused on unit-by-unit analyses with prescriptive retirement timing assumptions, was never intended to inform retirement decisions, but rather to inform the more in-depth and refined analysis in the subsequent portfolio-development process. The portfolio-development process is where PacifiCorp produced a range of different resource portfolios that meet projected gaps in the load and resource balance, each uniquely characterized by the type, timing, and location of new resources in PacifiCorp's system that considers a wide range of potential coal retirement dates and other planning uncertainties. In the resource portfolio analysis step, PacifiCorp conducted targeted reliability analysis to ensure portfolios had sufficient flexible capacity resources to meet reliability requirements. PacifiCorp then analyzed these different resource portfolios to measure the comparative cost, risk, reliability and emission levels. This resource portfolio analysis informed selection of a preferred portfolio and development of the associated near-term resource action plan. Throughout this process, PacifiCorp considered a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies were are also done to produce specific modeling assumptions.

Figure 1.1 – Key Elements of PacifiCorp's 2019 IRP Approach



Preferred Portfolio Highlights

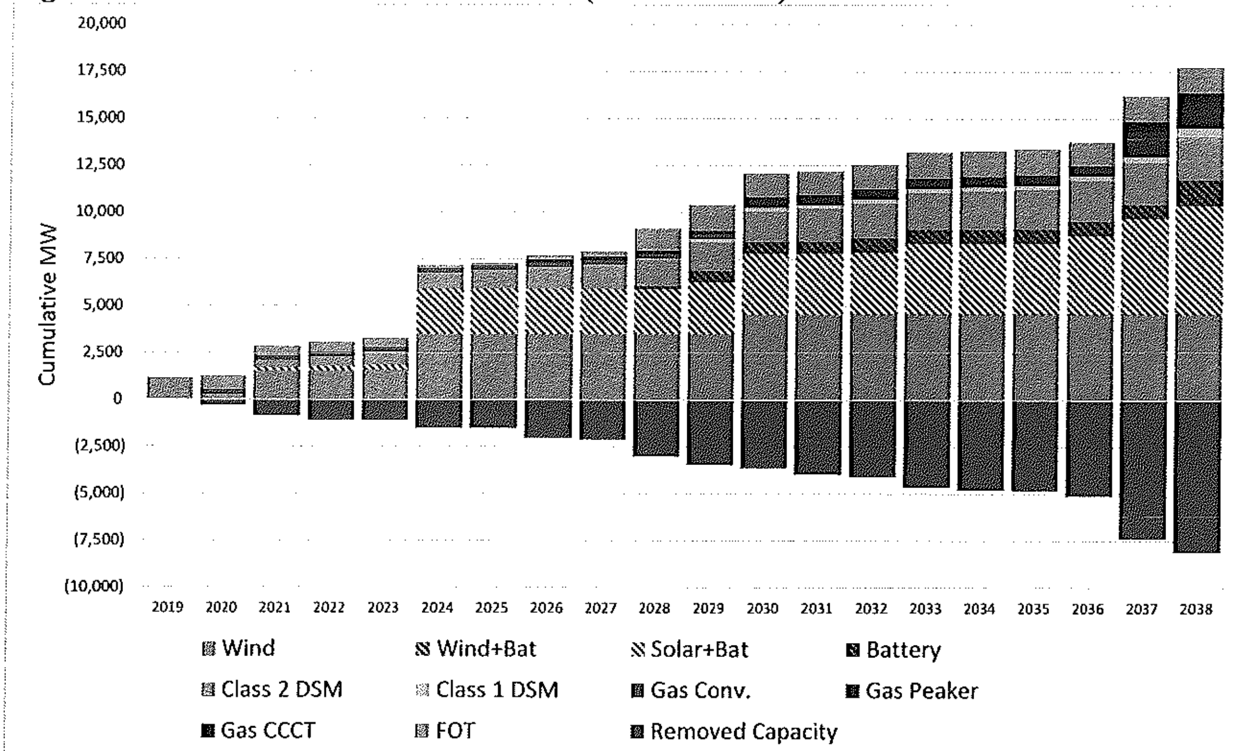
PacifiCorp's selection of the 2019 IRP preferred portfolio is supported by comprehensive data analysis and an extensive stakeholder input process, described in the chapters that follow. Figure 1.2 shows that PacifiCorp's preferred portfolio continues to include new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, and for the first time, significant battery storage resources. By the end of 2023, the preferred portfolio includes nearly 3,000 MW of new solar resources and more than 3,500 MW of new wind resources, inclusive of resources that will come online by the end of 2020 that were not in the 2017 IRP.[4] The preferred portfolio also includes nearly 600 MW of battery storage capacity (all collocated with

[4] *Id.*

new solar resources), and over 700 MW of incremental energy efficiency and new direct load control resources.

Over the 20-year planning horizon, the preferred portfolio includes more than 4,600 MW of new wind resources, more than 6,300 MW of new solar resources, more than 2,800 MW of battery storage (nearly 1,400 MW of which are stand-alone storage resources starting in 2028), and more than 2,700 MW of incremental energy efficiency and new direct load control resources.[5] While the preferred portfolio includes new natural gas peaking capacity beginning 2026, this falls outside of the 2019 IRP action plan window, which provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain long-term system reliability.

Figure 1.2 – 2019 IRP Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes a 400-mile transmission line known as Gateway South, planned to come online by the end of 2023, that will connect southeastern Wyoming and northern Utah. The new transmission line is in addition to the 140-mile Gateway West transmission line in Wyoming currently under construction as part of PacifiCorp's Energy Vision 2020 initiative. The preferred portfolio further includes near-term transmission upgrades in Utah and Washington. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources. Table 1.1 summarizes the incremental transmission projects included in the 2019 IRP preferred portfolio, and Table 1.2 summarizes the total amount of initial capital investment required to deliver incremental transmission and resource investments through the 20-year planning period of the 2019 IRP.

[5] *Id.*

Table 1.1 – Transmission Projects Included in the 2019 IRP Preferred Portfolio*

Year	Resource(s)	From	To	Description
2023	69 MW Wind (2023) 231 MW Solar (2024)	Within Southern UT Transmission Area		Enables 300 MW of interconnection: UT Valley 345-138 kV + 138 kV reinforcement ($8m)
2024	354 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 1 ($0)
2024	674 MW Solar (2024)	Within Northern UT Transmission Area		Enables 600 MW of interconnection: Northern UT 345 kV reinforcement ($30m)
2024	1,920 MW Wind (2024)	Aeolus WY	UT North	Enables 1,920 MW of interconnection with 1,700 MW of TTC: Energy Gateway South ($1,752m)
2024	395 MW Solar (2024) 10 MW Wind (2029)	Within Yakima WA Transmission Area		Enables 405 MW of interconnection: local reinforcement ($3m)
2024	359 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 2 ($0)
2030	1,040 MW Wind (2030) 60 MW Wind (2032)	Goshen ID	UT North	Enables 1,100 MW of interconnection with 800 MW of TTC ($254m)
2030	500 MW Solar (2030)	Within Southern UT Transmission Area		Enables 500 MW of interconnection: UT Valley local area reinforcement ($206m)
2033	475 MW Solar (2033)	Within Southern OR Transmission Area		Enables 475 MW of interconnection: Medford area 500 kV-230 kV reinforcement ($102m)
2036	419 MW Solar (2036)	Yakima WA	Southern OR	Enables 430 MW of interconnection with 450 MW of TTC: Yakima WA to Bend OR 230 kV ($255m)
2037	909 MW Solar (2037)	Southern UT	Northern UT	Reclaimed transmission upon retirement of Huntington 1-2 ($0)
2037	443 MW Gas (2037)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement ($40m)
2037	370 MW Gas (2037)	Within Southwest WY Transmission Area		Enables 500 MW of interconnection: separation of double circuit 230 kV lines ($39m)
2038	702 MW Solar (2038)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 3-4 ($0)

*Note: TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

Table 1.2 – Total Initial Capital to Deliver Preferred Portfolio Transmission and Resource Investments ($ million)

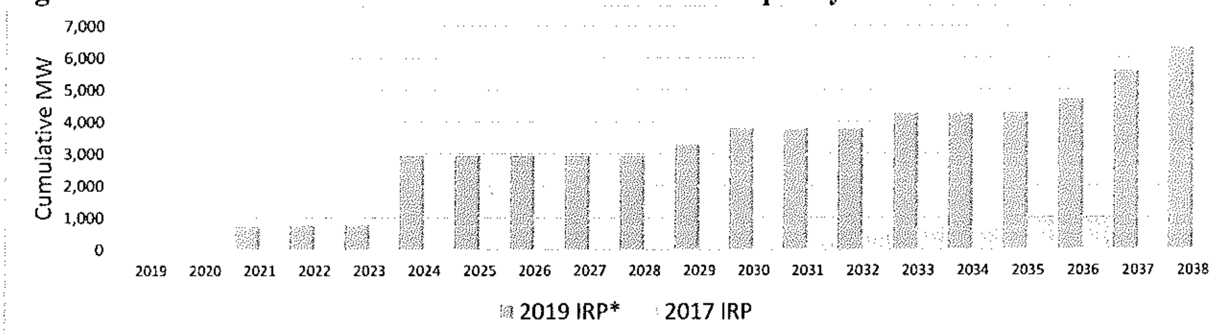
State	Transmission	Resources	Total
Idaho	$254	$1,659	$1,912
Oregon	$264	$2,540	$2,804
Utah	$1,004	$3,466	$4,470
Washington	$136	$1,509	$1,644
Wyoming	$765	$5,376	$6,141
Colorado	$370	$0	$370
Total	$2,792	$14,550	$17,342

New Solar Resources

The 2019 IRP preferred portfolio includes more than 3,000 MW of new solar by the end of 2023, which accounts for resources that will be online by the end of 2020 but not in the 2017 IRP, and more than 6,300 MW of new solar by 2038 as shown in Figure 1.3.[6]

[6] *Id.*

Figure 1.3 – 2019 IRP Preferred Portfolio New Solar Capacity*

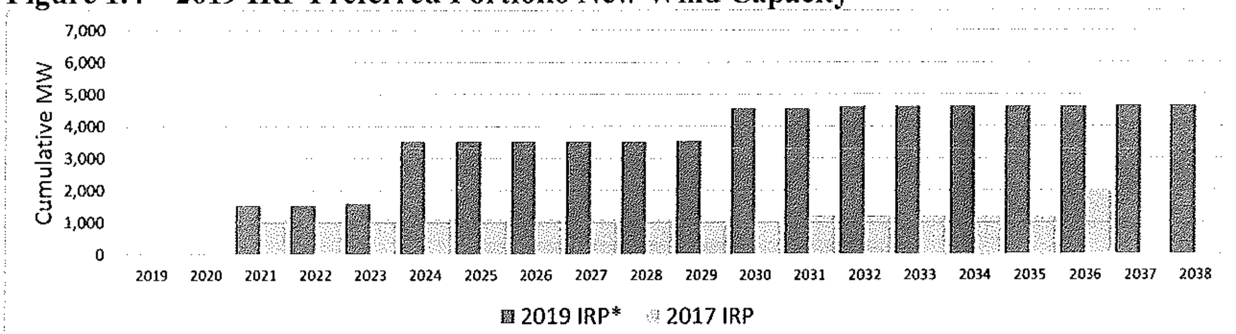


*Note: 2019 IRP solar capacity shown in the figure includes 559 MW of contracted new solar (all power-purchase agreements) that was not identified in the 2017 IRP. These resources will be online by the end of 2020 and are shown in the first full year of operation (the year after year-online dates). Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.

New Wind Resources

As shown in Figure 1.4, PacifiCorp's 2019 IRP preferred portfolio includes more than 3,500 MW of new wind generation by the end of 2023, which accounts for new resources that will come online by the end of 2020 but not in the 2017 IRP, and more than 4,600 MW of new wind by 2038.[7]

Figure 1.4 – 2019 IRP Preferred Portfolio New Wind Capacity*



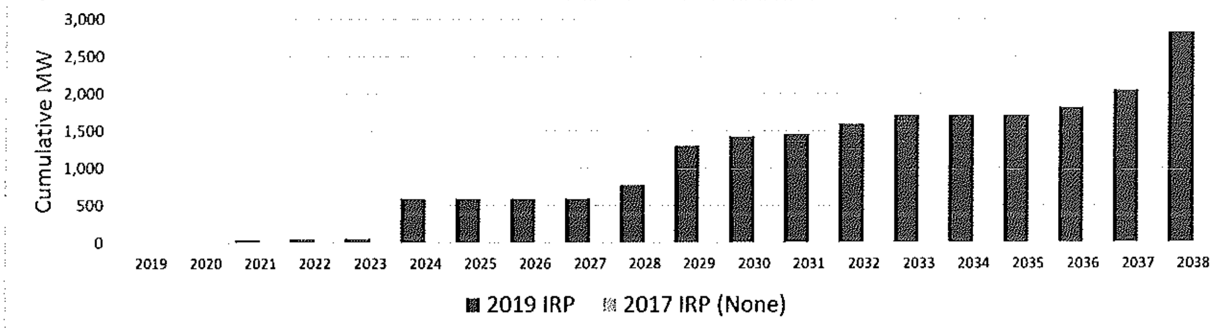
*Note: 2019 IRP wind capacity shown in the figure includes 1,533 MW of contracted new wind (21 percent power-purchase agreements) that was either identified in the 2017 IRP and is under construction or that was not identified in the 2017 IRP and is under contract. These resources will come on-line by the end of 2020. These resources are shown in the first full year of operation (the year after year-end online dates). Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.

New Storage Resources

This is the first PacifiCorp IRP that identifies new battery storage resources as part of its least-cost, least-risk portfolio. As shown in Figure 1.5, PacifiCorp's 2019 IRP preferred portfolio includes nearly 600 MW of battery storage by the end of 2023. All of the storage resources planned through this period are paired with new solar generation. The plan also adds nearly 1,400 MW of stand-alone storage resources starting in 2028.

[7] *Id.*

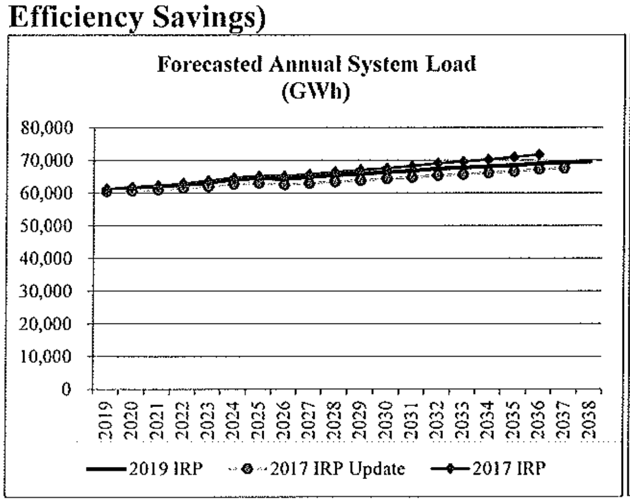
Figure 1.5 – 2019 IRP Preferred Portfolio New Storage Capacity

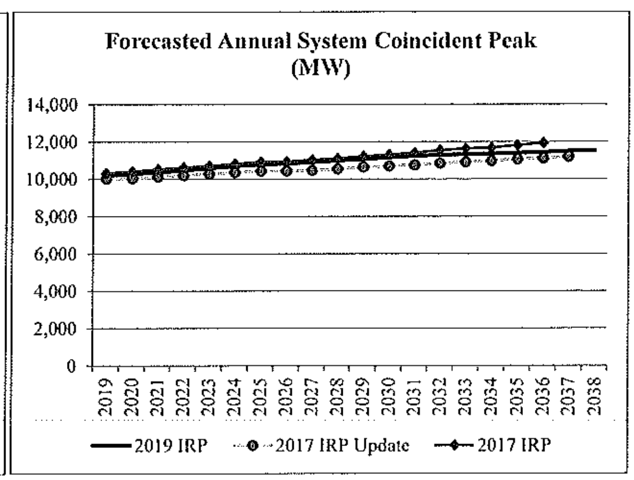


Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and direct load control programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 1.6 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2017 IRP and 2017 IRP Update. On average, forecasted system load is up 2.4 percent and forecasted coincident system peak is up 3.4 percent when compared to the 2017 IRP Update. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 0.73 percent for load and 0.64 percent for peak. Changes to PacifiCorp's load forecast are driven by higher projected demand from data centers driving up the commercial forecast and an increase the residential forecast.

Figure 1.6 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)

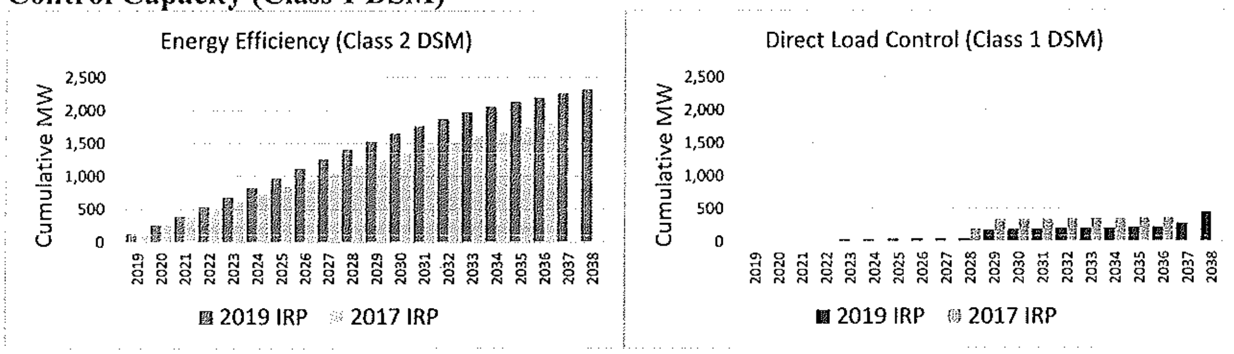




DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 1.7 compares total energy efficiency savings in the 2019 IRP preferred portfolio relative to the 2017 IRP preferred portfolio.

In addition to continued investment in energy efficiency programs, the preferred portfolio continues to show a role for incremental direct load control programs with total capacity reaching 444 MW by the end of the planning period. The chart to the right in Figure 1.7 compares total incremental capacity of direct load control program capacity in the 2019 IRP preferred portfolio relative to the 2017 IRP preferred portfolio and does not include capacity from existing programs.

Figure 1.7 – 2019 IRP Preferred Portfolio Energy Efficiency (Class 2 DSM) and Direct Load Control Capacity (Class 1 DSM)



Wholesale Power Market Prices and Purchases

Figure 1.8 shows that the 2019 IRP's base case forecast for natural gas and power prices has increased from those in the 2017 IRP and 2017 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts. The higher power prices observed in the 2019 IRP are primarily driven by the assumption of a carbon price that is higher and starts earlier (2025) than what was assumed in the 2017 IRP Update (2030).[8] Moreover, the 2019 IRP assumed higher natural gas prices than either the 2017 IRP or 2017 IRP Update as Henry Hub, in particular, is boosted by increasing LNG exports. While not shown in the figure below, the 2019 IRP also evaluated low and high price scenarios when evaluating the cost and risk of different resource portfolios.

Figure 1.8 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

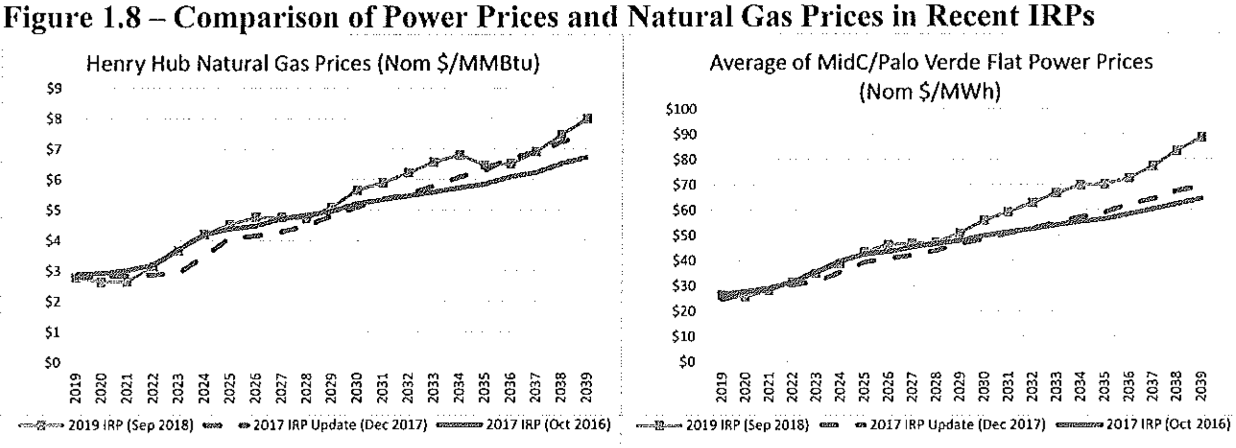
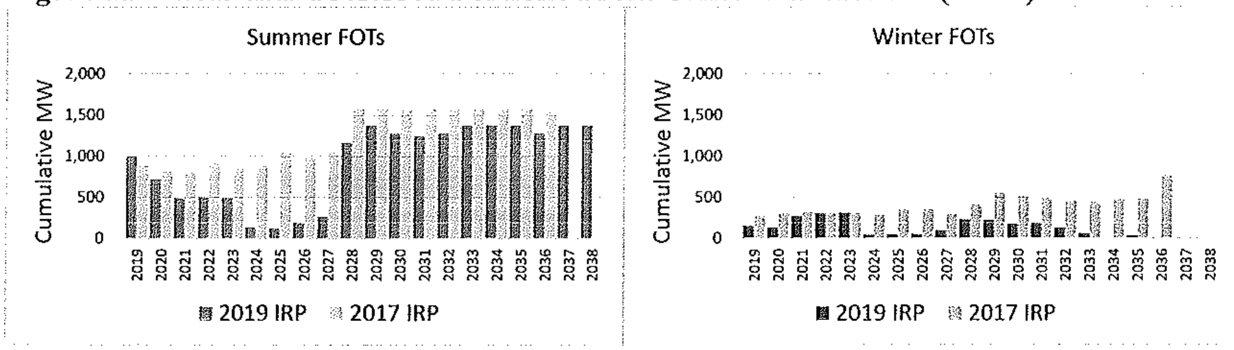


Figure 1.9 shows an overall decline in reliance on wholesale market firm purchases in the 2019 IRP preferred portfolio relative to the market purchases included in the 2017 IRP preferred portfolio. In particular, reliance on market purchases during summer peak periods averages 366

[8] The 2017 IRP did not assume a carbon price but, instead, reflected implementation of the Clean Power Plan.

MW per year over the 2020-2027 timeframe—down 60 percent from market purchases identified in the 2017 IRP preferred portfolio. This reduction in market purchases coincides with the period over which there are resource adequacy concerns in the region. While market purchases increase beyond 2027, PacifiCorp is actively participating in regional efforts to develop day-ahead markets and a resource adequacy program that will help unlock regional diversity and facilitate market transactions over the long term.

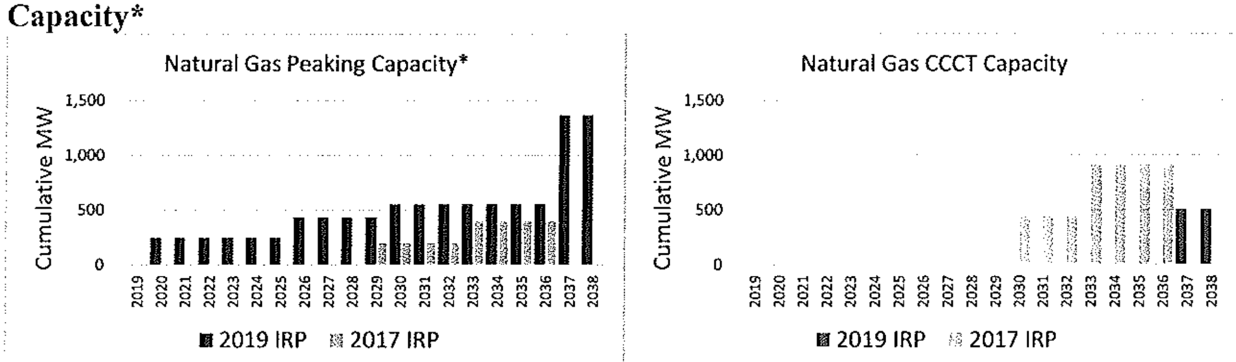
Figure 1.9 – 2019 IRP Preferred Portfolio Front Office Transactions (FOTs)



Natural Gas Resources

In the 2019 IRP preferred portfolio, Naughton Unit 3 is converted to natural gas in 2020, providing a low-cost resource to reliably serve our customers during peak-load periods. New natural gas peaking resources appear in the preferred portfolio starting in 2026, which is outside the action-plan window. This provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain system reliability long into the future.

Figure 1.10 – 2019 IRP Preferred Portfolio Natural Gas Peaking and Combined Cycle Capacity*



* Note: 2019 IRP natural gas peaking capacity includes the conversion of Naughton Unit 3 to natural gas in 2020 (247 MW).

Coal Retirements

Coal resources have been an important resource in PacifiCorp's resource portfolio. Changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums) has allowed the company to buy increasingly low-cost, zero-emissions renewable energy from market participants, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as those units approach retirement dates. Driven in part by ongoing cost pressures on existing coal-fired facilities