RFP to generation project developers and advertised the RFP in industry publications, and no potential bidders or developers raised any issues regarding the scope or terms and conditions.[299]

In addition, the 2020 RFP prohibited participation by ETI's affiliates.[300] Like past RFPs, ETI conducted a conference for bidders to field questions about the 2020 RFP. Finally, the RFP was overseen by an independent monitor (IM), Wayne Oliver, who reviewed its scope and administration, ultimately concluding that it was fair, unbiased, and equitable.[301]

Mr. Nguyen testified regarding the safeguards used to ensure impartiality in the RFP process which included segregating the self-build team from the evaluations team. Bidders were given the opportunity to ask questions and comment.[302] The self-build team was not informed during the evaluation process that it had submitted the only bid.[303] The IM oversaw the evaluation process.[304] And an independent engineer confirmed that the cost of the self-build proposal was consistent with the market.[305]

[299] ETI Ex. 29 (Weaver Reb.) at 45; ETI Ex. 7 (Nguyen Dir.) at 7, WP/PDN Testimony (Bates 113-29); Tr. at 259-260 (Oliver Redir.), 268 (Oliver Recross).

[300] ETI Ex. 7 (Nguyen Dir.), Exh. PDN-1 at 9 (Bates 37).

[301] ETI Ex. 14 (Oliver Dir.) at 7, Exh. WJO-3 at 53 (Bates 9, 107).

[302] ETI Ex. 7 (Nguyen Dir.) at 9-13.

[303] ETI Ex. 7 (Nguyen Dir.) at 12.

[304] ETI Ex. 7 (Nguyen Dir.) at 9-13; ETI Ex. 14 (Oliver Dir.) at 5-14.

[305] ETI Ex. 14 (Oliver Dir.) at 11-12.

2. RFP Parameters

TIEC faults the RFP process on grounds that it was limited to a CCGT and long-term contracts in ETI's Eastern Region and contained other onerous PPA-terms. Mr. Griffey opined that the RFP was designed to "all but guarantee no one else would bid."[306]

ETI notes that the 2020 RFP did not present a binary choice of the self-build proposal or a PPA; rather, it also solicited build-own-transfer (or turnkey) projects as well as acquisitions of existing resources.[307] ETI asserts that the PPA terms about which TIEC complains are consistent with terms included in prior RFPs that received PPA bid participation.[308] As such, there is no reasonable basis to conclude that including those same terms in the 2020 RFP would lead to a different result. Further, ETI consulted with the IM on the structure of the 2020 RFP, including the model PPA contract. ETI received no feedback from the IM or any potential bidder suggesting the PPA terms were overly restrictive.[309]

a) Targeted Solicitation

TIEC, Sierra Club, and OPUC claim that ETI should have issued an all-source solicitation to obtain more participation and identify different resource

[306] TIEC Ex. 1 (Griffey Dir.) at 45.

[307] ETI Ex. 7 (Nguyen Dir.), Exh. PDN-1 at 16-20 (Bates 44-48).

[308] ETI Ex. 25 (Nguyen Reb.) at 23-25; Tr. at 759-760 (Nguyen Redir.).

[309] ETI Ex. 25 (Nguyen Reb.) at 23.

options.[310] TIEC argues that by limiting the RFI to long-term resources of a specific type and size, the RFP eliminated almost all existing generation, renewables and demand-side management programs, as well as smaller CCGTs and options shorter than 10 years that could meet ETI's need.[311] Sierra Club faults the RFP for its limitation of a fossil fuel plant.

TIEC argues that by limiting the RFP to a CCGT of at least 1,000 MW and PPAs (from such plants) of at least 10 years in duration, the RFP prevented a wider range of options from being considered. TIEC notes that a contemporaneous RFP issued in MISO by a group of electric cooperatives in Louisiana (the 1803 Cooperative) for up to 1,000 MW of power to be delivered in MISO LRZ 9 called for resources to begin delivering power in 2025 and allowed for any time horizons up to 20 years, received 198 unique offers from 31 bidders, proposing a range of technologies, including CCGTs, peaking plants, solar, battery storage, and various market products.[312] The winning bids included a new 400 MW CCGT, numerous 20-year solar PPAs, a five-year partial requirements contract, and a five-year energy purchase with a capacity option.[313] Mr. Griffey also testified that there is excess capacity in MISO South that could be transmitted to ETI.[314]

ETI responds that both targeted and all-source solicitations are accepted industry practices and that the proper approach depends on the needs of the

[310] TIEC Ex. 1 (Griffey Dir.) at 33-34, 37-39; Sierra Club Ex. 1 (Glick Dir.) at 31, 36-37; OPUC Ex. 1 (Nalepa Dir.) at 23; Tr. at 103 (Nguyen Cross).

[311] TIEC Ex. 1 (Griffey Dir.) at 34.

[312] TIEC Ex. 1 (Griffey Dir.) at 32-33.

[313] TIEC Ex. 1 (Griffey Dir.) at 33.

[314] TIEC Ex. 1 (Griffey Dir.) at 34.

utility.[315] Mr. Nguyen testified that an all-source solicitation makes sense for the 1803 Cooperative RFP because it was seeking a new resource portfolio to serve its entire load.[316] By contrast, ETI already has a portfolio of resources, and its 2020 RFP was part of a plan to replace discrete thermal, dispatchable capacity at the Sabine site that is approaching the end of its useful life. Further, ETI has a need to replace that capacity in the same general location. In that situation, ETI argues its use of a targeted solicitation was more appropriate to make sure any bids received met its specific needs.[317] An all-source solicitation would not have assured any bids would have been capable of doing so.[318]

ETI argues that the 2019 Portfolio Analysis evaluated a variety of different resource options capable of serving as replacement capacity for the deactivating Sabine units.[319] That analysis did not identify any of the smaller resources or renewable resources considered as the most cost-effective and reliable resource. Instead, it identified a 2x1 CCGT, which ETI then used in its RFP. ETI thus argues that a reasonable process that considered the alternatives recommended by TIEC and Sierra Club does not yield an unreasonable RFP simply because that solicitation does not reconsider those same types of resources. ETI further notes that the RFP was open to existing generating resources.[320]

[315] ETI Ex. 25 (Nguyen Reb.) at 30-31; Tr. at 261-63, 272-73 (Oliver Redir.).

[316] ETI Ex. 25 (Nguyen Reb.) at 29-31.

[317] ETI Ex. 25 (Nguyen Reb.) at 29-31.

[318] ETI Ex. 25 (Nguyen Reb.) at 31.

[319] ETI Ex. 4 (Weaver Dir.), Exh. ABW-6 at 12 (Bates 102); TIEC Ex. 1 (Griffey Dir.) at 13.

[320] Tr. at 268 (Oliver Recross).

Moreover, ETI argues that it was reasonable to limit the RFP to PPA terms between 10-20 years. A utility entering into a PPA is subject to the constraints of the contract's commercial terms, typically prohibiting modification or termination for reasons related to economics or changing resource needs.[321] Therefore, according to Ms. Weaver, a PPA term of 10-20 years strikes a reasonable balance between providing a long-term resource, enabling developer financing, and preserving flexibility for ETI customers.[322]

In addition, the IM reviewed all RFP documents before they were posted to ensure they were clear, non-prejudicial and set forth reasonable parameters, and he raised no issues with the PPA terms.[323]

The ALJs find that ETI's RFP reasonably limited the solicitation to resources that ETI's 2019 Portfolio Analysis already identified as the most cost-effective and reliable. ETI sought to market test its self-build option which addressed ETI's specific needs, and an all-source solicitation would not have assured any bids would have been capable of doing so. Although ETI was assured of such a bid because of its own self-build option, a broader RFP solicitation would have, potentially, left ETI rejecting multiple bids and resources that would not have met its needs and ultimately choosing its self-build anyway. The ALJs note that this was the scenario in Docket No. 50277, which TIEC argues ETI should have emulated here. In that docket, El Paso Electric issued an all-source solicitation and

[321] ETI Ex. 29 (Weaver Reb.) at 47.

[322] ETI Ex. 29 (Weaver Reb.) at 47-48.

[323] ETI Ex. 29 (Weaver Reb.) at 48-49; ETI Ex. 14 (Oliver Dir.), Exh. WJO-4 (Bates 113-21).

allowed bidders to propose resources of various types, sizes, and contract lengths.[324] Despite the robust response from a wide variety of bidders (some 500), only a few were gas (a majority were solar, storage, and wind),[325] and the company ultimately selected its own gas self-build option, which, like here, would be located at an existing power station site.[326] Additionally, there is no evidence that El Paso Electric's resource need was as large or as unique as ETI's at issue. Here, despite the targeted solicitation, the IM found the process was fair, unbiased, and equitable.[327]

The ALJs find also that limiting the PPAs to terms of 10-20 years is reasonable. The evidence shows that these are common terms for PPAs and strike an appropriate balance between providing a long-term resource, enabling developer financing, and preserving flexibility for ETI customers.

b) Eastern Region Limitation

Ms. Weaver testified that locating the new generation in the Eastern Region would satisfy important long-term planning objectives, including improving reliability, increasing storm restoration capabilities and addressing resource adequacy and energy requirements.[328] She testified that limiting the 2020 RFP to resources located in the Eastern Region was proper to ensure a location close to the heavy industrial loads currently served by the Sabine units and to minimize reliance

[324] TIEC Ex. 42 at Bates 5 (D. 50277 Direct Testimony of Wayne Oliver).

[325] TIEC Ex. 42 at Bates 4-5 (D. 50277 Direct Testimony of Wayne Oliver); Tr. at 255-56 (Oliver Cross).

[326] Docket No. 50277, PFD at 3, 12 (Sept. 3, 2020).

[327] ETI Ex. 14 at 7 (Oliver Dir.), Exh. WJO-3 at 53 (Bates 9, 107).

[328] ETI Ex. 4 (Weaver Dir.) at 27-30.

on the transmission system and imported power, alleviate transmission constraints, and provide reactive power.[329] Additionally, siting the resource at the Sabine Power Station would reduce overall project costs by enabling ETI to use the existing transmission and gas infrastructure.[330] ETI claims that siting the new resource in the Eastern Region is necessary to address VLR concerns because, as previously noted, the Sabine units subject to deactivation are routinely called upon to provide VLR support.[331]

TIEC argues that the RFP should not have limited the resource location to ETI's Eastern Region because ETI has not demonstrated that it requires a plant of OCAPS' size for VLR or transmission reasons in the Eastern Region.[332] In support of this contention, TIEC relies on two confidential documents to argue that generation resources from Louisiana are available as potential VLR resources for Southwest Texas, and that new transmission lines can impact a VLR analysis.[333] ETI disagrees for the reasons stated in the confidential portions of its reply brief, arguing that its BP22 shows why TIEC's proposed VLR alternative is not viable.[334] The ALJs have reviewed the confidential portions of TIEC's and ETI's briefs, as well as the confidential exhibits, and agree with ETI that the evidence does not support TIEC's contention on this point.

[329] ETI Ex. 29 (Weaver Reb.) at 45-46; ETI Ex. 5 (Kline Dir.) at 4-14.

[330] ETI Ex. 29 (Weaver Reb.) at 47.

[331] ETI Ex. 26 (Owens Reb.) at 12-14; ETI Ex. 4 (Weaver Dir.), Exh. ABW-6 at Bates 196 of 260; ETI Ex. 5 (Kline Dir.) at 6, Exh. DK-2 at Bates 33 of 46.

[332] TIEC Ex. 1 (Griffey Dir.) at 38.

[333] TIEC Initial Brief at (HSPM) 12-13; TIEC Ex. 62 at Bates 6, 9-10 (HSPM); TIEC Ex. 59 (HSPM) at 15, n.3; Tr. at 303 (Kline Cross).

[334] ETI Confidential Reply Brief at 24; ETI Ex. 29A (Weaver Reb., Conf.), Exh. ABW-R-2 at Bates 8.

ETI further argues that reliance on transmission from other states for VLR, which TIEC's proposal would require, presents a reliability risk during severe weather events such as Hurricane Laura, when ETI lost its transmission ties to generation located in Louisiana and depended on local generation to keep much of its service territory unimpacted.[335] Mr. Kline testified that siting new generation to replace the Sabine units in ETI's Western Region would negatively impact reliability in the Eastern Region and, given the transmission constraints that would have to be overcome, would likely double the cost of placing OCAPS at the Sabine site.[336]

The ALJs find that ETI reasonably restricted the RFP resource to the Eastern Region, given the unique characteristics of the service area and need for VLR support.

c) PPA Terms

TIEC argues that bidder interest was further limited by several PPA terms including: a term that shifted the risk of regulatory disallowances to bidders; a term that allowed ETI to veto the sale of the resource of the PPA to certain other entities, and a lease accounting provision.[337] Because the lease accounting provision is the most contentious, it is addressed first.

[335] ETI Ex. 5 (Kline Dir.) at 12-13.

[336] ETI Ex. 21 (Kline Reb.) at 10-11.

[337] TIEC Ex. 1 (Griffey Dir.) at 39-40.

(i) The Lease Accounting Term

The 2020 RFP included the following lease accounting term:

> *Liability Transfer*. ESL will not accept the risk that any long-term liability will or may be recognized on the books of ETI (or any of its Affiliates) in connection with any PPA or Toll entered into pursuant to this RFP, whether the long-term liability is due to lease accounting, the accounting for a variable interest entity, or any other applicable accounting standard.[338]

The RFP went on to require PPA bidders to certify that, to the best of their knowledge, the PPA will not result in the recognition of a long-term liability by ETI on its books.[339] The presentation for the bidders conference also explained that "ETI will not accept the risk that any transfer to its books of any liability/asset associated with any PPA or Toll arising out of the RFP."[340]

(a) Impact on the Seller

Mr. Griffey testified that this PPA provision drove away bidders by placing unreasonable risk on PPA sellers because a future change in accounting guidelines is outside of a PPA seller's control.[341] Asking PPA providers to accept the risk that a PPA might be unilaterally cancelled by ETI in the future because of a change in accounting guidelines will be unacceptable to most PPA bidders or render their bids

[338] ETI Ex. 7 (Nguyen Dir.), Exh. PDN-1 at Bates 43, 51 (2.3.3).

[339] ETI Ex. 7 (Nguyen Dir.), Exh. PDN-1 at Bates 67-68 (section 6.1.5).

[340] TIEC Ex. 1 (Griffey Dir.) at 42.

[341] TIEC Ex. 1 (Griffey Dir.) at 41-43; TIEC Ex. 2 (Griffey Supp. Dir.) at 2-3.

uneconomic as they attempt to price in this risk.[342]

Mr. Griffey noted that an identical lease accounting provision was a major cause of a bidder abandoning the lowest cost PPA in ETI's prior RFP for solar proposals that resulted in the selection of the Liberty County Solar Facility (LCSF).[343] In that case, the ALJs concluded that ETI had failed to demonstrate that its insistence on the inclusion of the lease accounting provision was reasonable.[344] The Commission adopted the PFD and denied the CCN.[345]

Mr. Griffey further testified that the RFP was structured to practically guarantee that any qualifying PPA would constitute a lease because, under accounting guidance, a PPA is considered a lease, when (1) the PPA comes from an identified asset with no right of substitution for the seller; (2) the buyer controls dispatch and operation of the asset; and (3) the buyer has the right to obtain substantially all of the benefits of the asset.[346] Mr. Griffey testified that all of these factors are satisfied here.[347]

TIEC maintains that the RFP parameters made it commercially infeasible for a bidder to make such an offer because, under accounting guidance, "substantially all" is 90% or more, so the seller would then have to build a CCGT that is 11% bigger than

[342] TIEC Ex. 1 (Griffey Dir.) at 41.

[343] TIEC Ex. 1 (Griffey Dir.) at 41.

[344] Docket No. 51215, PFD at 27-28 (Jul. 19, 2021).

[345] Docket No. 51215, Order at 1 (Oct. 19, 2021).

[346] TIEC Ex. 2 (Griffey Supp. Dir.) at 9.

[347] TIEC Ex. 2 (Griffey Supp. Dir.) at 9-10.

the RFP amount—between 1,112 MW and 1,334 MW, to convey the 1,000-1,200 MW (89%) required by the RFP[348]—and then do something with the remaining 11% of 112 MW or so.[349] Trying to sell the 11% to a third party would not be commercially viable, according to Mr. Griffey, because ETI would have full dispatch rights over the underlying capacity of the PPA, and CCGTs have minimum output levels that are far higher than 11% (typically more in the range of 50%).[350] Thus, he opined, "the PPA seller would be limited to accepting at-best real-time energy prices for the 11% of the plant it did not sell to ETI."[351]

In response, Mr. Nguyen testified that a PPA bid could be structured to avoid lease accounting treatment, namely, to avoid conveying substantially all the economic benefit of the resource to ETI.[352] Mr. Nguyen testified that if 89% of a PPA is found to be economical by ETI, it stands to reason that the remaining 11% portion would also be economic.[353] Mr. Nguyen also testified that the seller would not be limited to selling the remaining 11% portion into the real-time market because the seller could make arrangements with ETI to sell that portion on the same basis that ETI would bid its 89% share into the market.[354] ETI insists that such a structured PPA would be similar to the ownership structure for MCPS, which it

[348] TIEC Ex. 2 (Griffey Supp. Dir.) at 11-12.

[349] TIEC Ex. 2 (Griffey Supp. Dir.) at 13.

[350] TIEC Ex. 2 (Griffey Supp. Dir.) at 11-12.

[351] TIEC Ex. 2 (Griffey Supp. Dir.) at 13.

[352] ETI Ex. 30 (Nguyen Supp. Reb.) at 2 (Bates 4); TIEC Ex. 2 (Griffey Supp. Dir.) at 11 (citing ETI response to TIEC RFI No. 20-8).

[353] ETI Ex. 30 (Nguyen Supp. Reb.) at 2-3.

[354] ETI Ex. 30 (Nguyen Supp. Reb.) at 3.

shares with ETEC.[355] ETI maintains sole discretion regarding operation and maintenance of MCPS, and ETEC takes its allotted share of as-available energy.[356] A motivated PPA bidder, ETI argues, had the option to structure a bid to avoid lease accounting or to take exception to the provisions and propose an alternative approach to address ETI's concerns.

Mr. Nguyen asserted that other utilities have included similar terms in their RFPs and gave three examples.[357] TIEC points out, however, that these examples include only one non-ETI utility RFP (PaciCorp) that prohibited PPAs that would be deemed leases, and could not identify any non-ETI RFPs that included the termination provision for future accounting changes.[358]

At the hearing, Mr. Nguyen testified that the RFP allowed bidders to propose alternate terms and negotiate exceptions or variances during commercial negotiations.[359]

[355] Docket No. 50790, Order at 11-12, 15 (FoF Nos. 61-64, OP No. 3) (Apr. 7, 2021).

[356] Docket No. 50790, Order at 3 (FoF No. 10).

[357] ETI Ex. 30 (Nguyen Supp. Reb.) at 1-2, Exh. PDN-SR-1 (ETI response to TIEC RFI No. 20-10) at Bates 18-17 (Public Service Company of Colorado 2017 RFP, Section 2.7), 65-66, 170-71 (PaciCorp 2017 RFP, section 4.B, 5.F), 144 (Mississippi Power 2022 RFP, Variable Interest Entity); TIEC Ex. 74 (ETI response to TIEC 21-1). On cross-examination, Mr. Nguyen was not able to confirm whether the variable interest entity included in the Mississippi Power RFP was the same thing as a capital lease or treated under a different accounting standard than government leases. Tr. at 757-58 (Nguyen Cross).

[358] TIEC Ex. 74 (ETI response to TIEC RFI No. 21-1).

[359] Tr. at 744-45 (Nguyen Cross).

(b) Impact on ETI

Mr. Griffey further testified that the impact of moving an existing PPA on to ETI's balance sheet is unclear.[360] He testified the risks associated with a PPA are assessed by credit ratings agencies when the PPA is executed.[361] Therefore, if the only thing that changes about an already-in-effect PPA is that it is deemed a lease in the future, this would not change any of the risks associated with that PPA.[362] Credit ratings agencies, he opined, are not required to mechanically apply Generally Accepted Accounting Principles when performing their ratings analyses.[363] Rather, he opined, credit rating agencies have discretion regarding their attribution of debt, so such a lease accounting treatment is uncertain.[364] Thus, according to Mr. Griffey, it is unclear whether an accounting change that required placing a previously off-balance sheet PPA on a utility's balance sheet would result in a change in credit rating, which is what ETI envisions.[365]

ETI contends that the concern regarding the lease accounting treatment is very real. ETI rebuttal witness Ellen Lapson, CPA, an expert on utility credit analysis, explained that a radical change in U.S. lease accounting took place in 2019 when the Financial Accounting Standards Board (FASB) implemented a new lease accounting standard, ASC 842, first announced in 2016.[366] ASC 842 can cause a

[360] TIEC Ex. 1 (Griffey Dir.) at 41.

[361] TIEC Ex. 2 (Griffey Supp. Dir.) at 7.

[362] TIEC Ex. 2 (Griffey Supp. Dir.) at 7.

[363] TIEC Ex. 2 (Griffey Supp. Dir.) at 5-6.

[364] TIEC Ex. 2 (Griffey Supp. Dir.) at 4.

[365] TIEC Ex. 2 (Griffey Supp. Dir.) at 7-8.

[366] ETI Ex. 22 (Lapson Reb.) at 11-12.

long-term PPA to be recognized as a capitalized lease liability on a utility's balance sheet.[367] If that occurred, credit rating agencies would then be required to consider that lease liability as a form of debt in assessing the utility's credit rating. In other words, the PPA obligation would contribute to the utility's debt leverage and could have a deleterious effect on its credit rating.[368]

Ms. Lapson testified that, notwithstanding Mr. Griffey's assertion that such a result is uncertain, "[i]f a power contract is classified as a lease for financial statements, then it will be treated as a component of debt by the [credit rating agencies] in their rating analyses . . . lease liabilities must be counted as debt obligations in calculating debt ratios."[369] Ms. Lapson testified that the discretion by credit rating agencies is "to increase the recognition of debt that is not reported on financial statements and not to reduce debt that does appear on the financial statements."[370] Ms. Lapson performed a pro forma analysis to demonstrate how a PPA of similar magnitude to OCAPS on ETI's balance sheet would impact ETI. She found that such accounting treatment would result in a dramatic and unfavorable change in the Company's capital structure, increasing debt from 49% of capital structure to 59% and reducing equity as a percent of capital from 50% to approximately 40%.[371] Under Ms. Lapson's analysis, the cash flow leverage ratio

[367] ETI Ex. 22 (Lapson Reb.) at 11-12.

[368] ETI Ex. 22 (Lapson Reb.) at 12-14; ETI Ex. 31 (Lapson Supp. Reb.) at 3-6.

[369] ETI Ex. 22 (Lapson Reb.) at 22; ETI Ex. 31 (Lapson Supp. Reb.) at 5-6.

[370] ETI Ex. 31 (Lapson Supp. Reb.) at 5.

[371] ETI Ex. 22 (Lapson Reb.) at 15-17.

that Moody's considers the benchmark for ETI's credit rating would decline below the threshold necessary to support ETI's current credit rating.[372]

ETI further argues that accepting PPAs that could be deemed leases and, therefore, considered as debt, would have exposed ETI to the risk of losing the ability to access capital in a manner consistent with ETI's obligation to reliably serve customers. That risk accounts for the probability of such a downgrade:

> On the one hand, credit rating agencies have discretion to set a credit rating that is inconsistent with the agency's financial leverage guidelines for the rating category, providing that the agency discloses that the rating represents an exception from its standards and explains the reason for the exception. On the other hand, one or both credit rating agencies could lower ETI's ratings to conform to the amount of financial leverage shown in the financial statements. Thus, to protect its own credit ratings, ETI is forced to consider the possibility that one or both credit rating agencies will give weight to the reported lease liability . . . .[373]

ETI thus argues that it would not be reasonable for management to put the Company's access to capital at risk in that manner.

Maintaining its position that downgraded credit ratings is not certain, TIEC notes that Ms. Lapson admitted in discovery that the lease accounting "requirement" is actually that ratings agencies publish their methodologies and disclose whether they followed them, with the agencies also having discretion to

[372] ETI Ex. 22 (Lapson Reb.) at 17-18 (Bates 19-20); ETI Ex. 31 (Lapson Reb.) at 2.

[373] ETI Ex. 31 (Lapson Supp. Reb.) at 6.

revise their methodologies as necessary.[374] Ms. Lapson also admitted that she is unaware of any instances of PPAs being reclassified as leases since ASC 842 was implemented.[375] However, Ms. Lapson explained that this may be a result of the affected community avoiding its effect by taking advantage of the three-year lead time to revise their agreements.[376]

Ms. Lapson opined that if the lease conditions have no precedent in contracts that have been approved by the Commission, it is because "few, if any, new gas-fired power resources have been proposed by utilities in this jurisdiction since 2019, the year in which ASC 842 was implemented. . . . Recent proposed power contracts may have been for wind or solar resources that have different characteristics from the 2020 RFP, making them less likely to be classified as a lease."[377]

(ii) Other Terms

Regarding the regulatory disallowance and sale limitation terms, Mr. Nguyen testified to the underlying purpose of the PPA terms, stating that:

> [T]he terms for the PPAs are designed to protect ETI's financial and operational health, which, in turn, is for the benefit of its customers. They address low probability but high impact risks. For example, if ETI were to suffer a substantial disallowance on a 20-year, 1,000+MW PPA, such a result would materially affect ETI's financial health and its ability to invest in its system to provide reliable service. ETI

[374] TIEC Ex. 2 (Griffey Supp. Dir.), Exh. CSG-S-1 at 2 (Bates 022) (ETI response to TIEC RFI No. 17-32).

[375] TIEC Ex. 2 (Griffey Supp. Dir.), Exh. CSG-S-1 at 3 (Bates 023).

[376] TIEC Ex. 2 (Griffey Supp. Dir.), Exh. CSG-S-1 at 3 (Bates 023).

[377] ETI Ex. 22 (Lapson Reb.) at 20, n.21.

> believes mitigating that risk by having a PPA bidder share that risk, particularly if that risk stems from conduct by the seller, encourages bidders to make reasonable, competitive offers that will avoid that outcome.[378]

Thus, ETI argues, it is not unreasonable to place the risk of a regulatory disallowance stemming from a seller's actions on that seller, as opposed to ETI.

Mr. Nguyen testified that limiting the ability to sell the unit supporting the PPA is designed to protect customer interests, given the resource it would be replacing, and to ensure that the replacement capacity is available and reliable throughout its life cycle. The RFP process evaluates a bidder's financial capacity and experience for similar reasons.[379]

d) Analysis

The ALJs find that ETI reasonably protected its financial and operational health through the PPA terms. The ALJs find that placing the risk of regulatory disallowance on the seller is facially reasonable. Additionally, restricting the seller's ability to sell the underlying asset was reasonable to ensure that the asset is available and reliable throughout the term of the PPA.

The ALJs further find that ETI reasonably protected itself from the potential effects of the lease accounting guidelines by refusing to accept the risk of any transfer to its books of any liability associated with any PPA arising out of the RFP.

[378] ETI Ex. 25 (Nguyen Reb.) at 24.

[379] ETI Ex. 25 (Nguyen Reb.) at 24-25.

Ms. Lapson credibly testified that recording the leases as debt, particularly in a solicitation of this size (some 40% of ETI's rate base) could have a shocking effect on ETI's credit rating, which in turn would materially alter the Company's capital structure, pushing its debt to equity ratio from approximately 50%/50% to 60%/40%, thereby downgrading its credit rating. Moreover, the ALJs are persuaded that such an accounting and rating treatment is a near certainty. Mr. Griffey's testimony to the contrary is unpersuasive. As Ms. Lapson testified, any credit rating discretion favors recognizing debt, not reducing it. Thus, the ALJs find that ETI reasonably protected itself against the risk of that eventuality. The ALJs reach this finding based on the weight of Ms. Lapson's testimony.[380]

The ALJs are not persuaded, however, that a bidder could have avoided the above-described lease accounting treatment. Mr. Nguyen's testimony in that regard is implausible, as Mr. Griffey convincingly demonstrated,[381] and there is no evidence that any bidder has bid into an RFP notwithstanding such a term. Ms. Lapson opined that this may be due to the novelty of the accounting standard and the type and size of the resource sought in this RFP.[382] Although the ownership structure for MCPS may serve as an example of one option for a seller, there is no evidence that MCPS's co-owner labors under the same risk ETI proposes here. However, the ALJs find TIEC's evidence that the lease accounting provision drove away bids inconclusive. Although there was such evidence in the LCSF proceeding, here there is none. Here, no bidder asked questions or proposed alternate terms,

[380] ETI Ex. 22 (Lapson Reb.), Exh. EL-R-1.

[381] TIEC Ex. 2 (Griffey Supp. Dir.) at 8-15.

[382] ETI Ex. 22 (Lapson Reb.) at 20, n.21 .

despite having that opportunity; the absence of any comment or bid of any resource suggests a different reason for low bidder interest.

3. Lack of Participation

The RFP failed to attract any outside bids. TIEC notes that the RFPs in both the LCSF[383] and MCPS[384] CCN proceedings failed to attract robust responses, and that in the LCSF RFP, in which ETI received 10 bids from four proposed resources, the participation was so limited that the IM (Mr. Oliver) only agreed to proceed because restarting the process would have risked the benefits of solar Investment Tax Credits.[385] Here, Mr. Oliver did not recommend restarting the process, despite the OCAPS RFP receiving no outside bids at all.[386]

Mr. Griffey testified that the lack of interest should have been apparent by the low attendance at the bidders' conference, which would have made ETI's self-build team aware of the lack of interested competition,[387] as well as the subsequent single question from a potential bidder regarding extending the deadline for RFP responses to provide a better chance for a response.[388] OPUC argues that ETI should have heeded that suggestion and postponed the bid response date,

[383] TIEC Ex. 46 at Bates 5 (Docket No. 51215, Redacted LCSF IM Report).

[384] TIEC Ex. 47 at Bates 6 (Docket No. 46416, Direct Testimony of Wayne Oliver).

[385] Docket No. 51215, PFD at 90 (FoF 48).

[386] Tr. at 256-57 (Oliver Cross).

[387] TIEC Ex. 1 (Griffey Dir.) at 43.

[388] TIEC Ex. 1 (Griffey Dir.) at 43; ETI Ex. 14 (Oliver Dir.), Exh. WJO-3 at 18 (Bates 72 of 122).

given that the RFP was issued at the height of the COVID-19 pandemic.[389] OPUC recommends that the Commission require ETI to re-conduct the RFP.[390]

TIEC, OPUC, and Sierra Club argue that because of the lack of participation, the RFP did not test the market for competitive alternatives to ETI's self-build CCGT, and, therefore, ETI failed to demonstrate that the OCAPS project is necessary for the service accommodation, convenience, or safety of the public relative to other potential alternatives.

In contrast, ETI argues that the RFP did test the market and the resulting lack of participation is consistent with current market conditions and serves no basis to conclude the RFP was not appropriately designed or conducted. More specifically, Mr. Nguyen testified that the lack of RFP participation is a reflection of the current market for renewable generation projects.[391] Mr. Oliver confirmed this assertion and added that there have been very few bids for large gas unit projects in recent RFPs.[392] He testified that even in all source RFPs, most of the activity is in renewables.[393] Mr. Oliver referenced one recent all source RFP that garnered over 100 submissions, only one of which was a gas project, which was also an existing project.[394] Similarly, as noted above, Ms. Lapson opined that one reason the lease accounting provisions have not appeared in contracts approved by the

389 OPUC Ex. 1 (Nalepa Dir.) at 14.

390 OPUC Initial Brief at 9.

391 ETI Ex. 25 (Nguyen Reb.) at 29.

392 Tr. at 255-56, 257-59 (Oliver Cross).

393 Tr. at 258 (Oliver Redir.).

394 Tr. at 258 (Oliver Redir.).

Commission is the shift to wind and solar projects that have different characteristics than the 2020 RFP.[395] ETI notes, moreover, that only one of the almost 200 offers in the 1803 Cooperative RFP was a CCGT project.

ETI further disagrees with the contention that the lack of participation in the 2020 RFP shows that OCAPS is not necessary. ETI argues first that in the 2019 Portfolio Analysis it compared a generic 2x1 CCCT (as a surrogate for OCAPS) to alternative resources.[396] Second, ETI contends that RFPs, which are not required in Texas, are not designed or intended to establish the need for a resource.[397] Rather, RFPs are designed to fill a need, which is demonstrated by comparing expected resources to forecasted load plus a reserve margin.[398] Thus, ETI argues, neither the parameters of the 2020 RFP nor the levels of participation by market participants bear any relationship to the demonstrated need the RFP was intended to address.

ETI contends it has real and pressing resource needs right now and re-conducting the RFP process, as OPUC suggests, would potentially add years to the process of adding physical capacity to ETI's service area. Ms. Weaver testified that there is no indication that restarting the RFP with a broader scope would have

[395] ETI Ex. 22 (Lapson Reb.) at 20.

[396] ETI Ex. 4 (Weaver Dir.), Exh. ABW-6 at 12 and 19 (Bates 102 and 109).

[397] *See* Senate Bill 7 § 61, 76th Leg. R.S. (1999), repealing PURA ch. 34, § 34.022 (requiring integrated resource plans to include the proposed means of soliciting future estimated resources, if they exist).

[398] ETI Ex. 4 (Weaver Dir.) at 9-12, Exh. ABW-3 (Bates 39).

resulted in more bids or produced a resource that would better meet the Company's needs than OCAPS.[399]

Regarding the lack of participation, the IM noted the following:

> The reason why competition was limited was not clear to the IM. While there may be a market perception that ESL has a competitive advantage associated with the self-build option, this view was not raised by any bidder. The IM did not experience any instances where it appeared that the self-build option was treated preferentially.[400]

Similarly, Mr. Nalepa testified that this observation regarding competitive advantage "has merit as the self-build option would be located at an existing plant site and have access to existing transmission and fuel supply. These can be significant advantages over other new-build options."[401]

With respect to the impact of the COVID-19 pandemic on bids, Mr. Nguyen testified that ETI specifically solicited feedback from potential bidders regarding the RFP timing in light of the pandemic.[402] He testified that ETI did not extend the RFP deadline because the one potential bidder who suggested extending it, gave no specifics on how much more time it would need and ceased to engage in the RFP process.[403] Moreover, many RFPs for supply-side resources were issued in 2020

[399] ETI Ex. 29 (Weaver Reb.) at 51-52.

[400] ETI Ex. 14 (Oliver Dir.), Exh. WJO-3 at Bates 111.

[401] OPUC Ex. 1 (Nalepa Dir.) at 23; ETI Ex. 29 (Weaver Reb.) at 52; ETI Ex. 25 (Nguyen Reb.) at 31-32.

[402] ETI Ex. 25 (Nguyen Reb.) at 27, Exh. PDN-R-2 Bates 54 of 55 ("ESL encourages potential bidders to provide feedback on this timeline, specifically bidder's concerns on being able to effectively develop a full proposal given the current or anticipated restrictions or disruptions caused by the COVID-19 impact.").

[403] ETI Ex. 25 (Nguyen Reb.) at 27-28.

early in the pandemic, including an RFP from Entergy Louisiana, which received numerous bidder submissions. ETI's self-build proposal team developed its proposal, and the evaluation process was conducted in a remote work platform within the time allotted by the RFP.[404] Additionally, ETI did not consider the low turnout at the bidders' conference as indicative of bidder interest because in the past, bidders who had not attended a conference had nevertheless submitted bids.[405] Finally, the project timeline warranted moving ahead to assure the resource would be available as planned, particularly where reissuance of the 2020 RFP could not assure bidder participation.[406]

4. Analysis

The ALJs find that the 2020 RFP reasonably solicited a resource located in ETI's Eastern Region, as opposed to an all-source solicitation, to meet a need for an identified resource. The ALJs also agree with ETI that the lack of participation, per se, does not equate to failure to demonstrate need, which has already been demonstrated. There is no indication that different terms would have produced a different outcome.

Moreover, the lack of participation at the bidders' conference was not grounds to call off the RFP or to start over, and attendance was not mandatory or a necessary indicator of interest. Nor is there any credible evidence that the onset of the COVID-19 pandemic hindered bidders. Mr. Nguyen testified that the self-build

[404] ETI Ex. 25 (Nguyen Reb.) at 28.

[405] ETI Ex. 25 (Nguyen Reb.) at 26.

[406] ETI Ex. 25 (Nguyen Reb.), Exh. PDN-R-2 (Bates 51-54).

bid was timely developed and evaluated remotely. The evidence shows that the energy industry, including its regulation, was able to quickly adapt to an altered work environment without significant disruption due to the pandemic.[407]

The preponderance of the evidence shows that the lack of participation can reasonably be attributed to a market shift toward renewables and a waning interest in CCCTs. Other contemporaneous RFPs, including the 1803 Cooperative, attracted little or no interest in new CCGTs, and none of OCAPS' size. This lack of participation may also be attributed to the perceived—indeed, real—competitive advantage of ETI. However, the ALJs find no evidence that the self-build bid was treated preferentially. Accordingly, the ALJs find it reasonable that ETI did not restart the process.

Thus, the ALJs find that the lack of participation in the 2020 RFP is consistent with current market conditions and serves as no basis to conclude the RFP was not appropriately designed or conducted.

VIII. HYDROGEN CO-FIRING CAPABILITY

Through House Bill 1510 in 2021, the Legislature directed the Commission to consider any potential economic or reliability benefits associated with the dual fuel and fuel storage capabilities in its evaluation of whether to grant a CCN. As some intervenors point out, hydrogen was not a part of the 2019 Portfolio Analysis or the RFP. This advanced capability was added to the 2x1 CCGT option in May

[407] *See, e.g.,* Docket No. 50277, Final Order at 3 (Oct. 16, 2020) (prehearing conference held on May 21, hearing on the merits held June 9, record close on July 7, 2020, with filing of reply briefs).

2021, two years after the completion of the 2019 Portfolio Analysis.[408] ETI proposes to construct OCAPS so that it will be capable of co-firing 30% hydrogen by volume at the outset, which will require an initial investment of approximately $91 million.[409]

A. Costs and Benefits of Dual Fuel and Fuel Storage Capabilities (P.O. Issue Nos. 23, 27, 39, 41-44)

1. ETI's Position

ETI argues that the hydrogen capability will provide immediate reliability benefits to ETI customers by reducing reliance on natural gas when supply is constrained. It also maintains that making this investment now will reduce the later cost of conversion to 100% hydrogen and significantly reduce the time of the plant outage during that conversion in the future. Mr. Nguyen testified that the reliability benefits of the dual fuel capability transcend, and would not be captured by, an economic analysis.[410] Conversely, ETI contends that hydrogen capability will augment the availability of stored gas—co-firing hydrogen can extend the period of time stored gas can support operations.[411]

ETI witness Robert E. Hebner, Ph.D., testified that hydrogen is expected to become cost-competitive with natural gas in the foreseeable future, at which point

[408] ETI Ex. 4 (Weaver Dir.), Exh. ABW-8 at 1 (Bates 247 of 260) (HSPM).

[409] *See* Tr. at 201 (Ruiz Cross) (As of February 24, 2022, ETI estimated the cost of the hydrogen component to be $91 million.).

[410] Tr. at 412–13 (Nguyen Redir.); Cities Ex. 4 (ETI response to Cities RFI No. 1-5).

[411] ETI Ex. 29 (Weaver Reb.) at 55-59; ETI Ex. 29A (Weaver Reb., Conf.) at 58 (Bates 5); *see* 16 TAC § 3.97 (Underground Storage in Salt Formations).

it can be used to reduce fuel costs to customers.[412] Dr. Hebner opined that given Texas's mature hydrogen economy, extensive hydrogen infrastructure, and abundance of renewable resources, he expects hydrogen to be cost competitive with natural gas in Texas early in the OCAPS life cycle, if not prior to commercial operation of the unit.[413] Until hydrogen is cost competitive with natural gas, ETI intends to use hydrogen only for reliability purposes, at which point, the need for generation would trump economics.[414]

Dr. Hebner further testified that hydrogen as a fuel source can make more efficient use of intermittent renewable generation. When energy from renewable resources is not needed to serve loads at the time generated, it can be used for electrolysis to produce hydrogen that can then be stored and used later when that intermittent generation is not able to fully serve loads.[415]

2. Other Parties' Positions

Staff, OPUC, TIEC, and Cities argue that the hydrogen co-firing capability of OCAPS should not proceed.

Staff believes that hydrogen capability, as proposed, will have significant negative impacts to the environment and would be substantially more expensive

[412] Tr. at 333 (Nguyen Cross), 434, 437–38 (Hebner Cross), 447–48 (Hebner Redir.), 450 (Hebner Recross).

[413] ETI Ex. 19 (Hebner Reb.) at 4; Tr. at 436–38 (Hebner Cross), 447–48 (Hebner Redir.), 450 (Hebner Recross); Staff Ex. 19 (ETI responses to Staff RFI No. 6-4).

[414] ETI Reply Brief at 45; ETI Ex. 29 (Weaver Reb.) at 60.

[415] ETI Ex. 13 (Hebner Dir.) at 8-10; Tr. at 447–48 (Hebner Redir.); *see also* ETI Ex. 19 (Heber Reb.), Exh. REH-R-1 (Bates 13-20).

than using natural gas. ETI intends initially to use "gray hydrogen."[416] Staff is concerned that gray hydrogen is produced using natural gas and creates carbon dioxide (CO2) emissions that are then released into the environment. Staff points out that, according to ETI's estimate, natural gas creates a total of 142 pounds of CO2 per million British Thermal Units (MMBtu) of energy whereas hydrogen produces a total of 184 pounds/MMBtu of CO2 emissions. Staff stresses that ETI's estimate does not include the energy loss and CO2 emissions resulting from the hydrogen-creation process.[417] Staff argues that hydrogen capability would produce substantially more CO2 emissions than using only natural gas and would be substantially more expensive.[418] Staff argues it is safe to assume that gray hydrogen will be the source of hydrogen used at OCAPS for the foreseeable future because "green hydrogen," which results in lower carbon emissions, is the most expensive type of hydrogen.[419] Staff notes that the pricing information provided by ETI for gray hydrogen shows that the average price is more than double the cost of burning the equivalent natural gas alone.[420]

Finally, Staff notes that there is no guarantee or timetable for 100% hydrogen capability (the opportunity for which is the basis for the capability now). As ETI witness Mr. Viamontes testified, hydrogen benefits are in addition to critical need and the project would need to move forward even without hydrogen capability, if

[416] ETI Ex. 19 (Hebner Reb) at 8; *see also* ETI Ex. 13 (Hebner Dir.) at 9 and ETI Ex. 19 (Hebner Reb) at 6-8 (regarding hydrogen color labels).

[417] Staff Ex. 17 at 2 (ETI responses to Staff RFI No. 6-1).

[418] Staff Ex. 1 (Ghanem Dir.) at 17.

[419] Staff Ex. 1 (Ghanem Dir.) at 17.

[420] Staff Ex. 12A (HSPM) at 2 (ETI responses to Staff RFI No. 3-4).

necessary.[421] In addition, ETI witness Mr. Ruiz stated that there is no timetable for when OCAPS could reach 100% hydrogen capacity and agreed that there is no guarantee that OCAPS would ever reach this capability during the life cycle of the facility.[422]

OPUC raises concerns regarding costs. OPUC states that in addition to the $65 million for costs directly attributable to the infrastructure needed to fire hydrogen, Mr. Nalepa identified an additional $84 million for costs associated with the ability to fire 100% hydrogen and to connect to hydrogen supplies that is not included in the OCAPS price.[423] OPUC stresses that ETI failed to provide any economic analysis that included the costs of burning hydrogen or any forecast for hydrogen prices and, as such, any supposed benefits asserted by ETI cannot be properly analyzed.[424]

Regarding ETI's assertion that hydrogen capability will increase reliability, OPUC contends that the location adjacent to the current Sabine Power Station would give OCAPS access to ETI's Spindletop natural gas storage facility, which should mitigate the impact of any natural gas curtailment issues.[425] Finally, OPUC notes that the Commission has repeatedly found arguments regarding future preparedness for federal policies and market conditions and related transition to

[421] Tr. at 52, 54–55 (Viamontes Cross)

[422] Tr. at 231 (Ruiz Cross).

[423] ETI Ex. 3A (Rainer Dir.) at 8.

[424] OPUC Ex. 1 (Nalepa Dir.) at 25.

[425] OPUC Ex. 1 (Nalepa Dir.) at 25.

low-carbon to be speculative.[426] Therefore, OPUC argues, it is unreasonable to rely on an assertion regarding possible low-carbon scenarios as a benefit of co-firing hydrogen. In sum, OPUC concludes that the hydrogen option would be cost-prohibitive and that the potential increased reliability is overstated considering OCAPS' location next to Spindletop.

TIEC emphasizes the lack of any economic or cost-benefit analysis to justify the cost of OCAPS' hydrogen component.[427] While noting that co-firing hydrogen at 30% could more than double the marginal cost of operating OCAPS, TIEC asserts ETI has failed to forecast or consider the future price of hydrogen on a dollar per thousand cubic feet or MMBtu basis. Mr. Griffey opined that hydrogen could become even less economic in the future.[428] TIEC next contends that co-firing hydrogen at 30% would also decrease OCAPS' capacity compared to firing 100% natural gas and would also increase the heat rate. TIEC points out that OCAPS would not even decrease carbon emissions as long as gray hydrogen is used, which, even Dr. Hebner, believes may increase in CO2 emissions.[429] Finally, TIEC argues that to determine whether the dual fuel benefit justifies the cost, one would need to compare it to other dual fuel capabilities. TIEC notes that ETI neither performed this study nor evaluated whether hydrogen provides a greater

[426] Docket No. 49737, Order at 8-9 (FoF 62 - 64) (Jul. 6, 2020); Docket No. 51215, Order at 12 (FoF 98-102) (Oct. 19, 2021).

[427] TIEC Ex. 1A (Griffey Dir., Conf.) at 94 (Bates 45); TIEC Ex. 1B at 2 (Griffey Dir., WP).

[428] TIEC Ex. 1B at 5 (Griffey Dir, WP); TIEC Ex. 1A (Griffey Dir., Conf.) at 95 (Bates 46); TIEC Ex. 1C (Griffey Dir., WP) (HSPM) at Bates 013-014.

[429] TIEC Ex. 1 (Griffey Dir.) at 94; Tr. at 428-429 (Hebner Cross).

benefit than the existing gas storage at Spindletop or liquid fuel back-up at OCAPS.[430]

While acknowledging many potential benefits of hydrogen as an alternative fuel source,[431] Cities nevertheless argue that the proposed hydrogen infrastructure should be excluded from OCAPS. Cities first argue that fueling OCAPS by hydrogen is not a currently economically viable alternative, as Dr. Hebner admitted,[432] and the date by which hydrogen will be cost-competitive with natural gas uncertain.[433] Mr. Nguyen testified that that "[w]e believe [hydrogen] can become economic within the 30-year life period [of OCAPS], but given the potential uncertainty, we didn't model that as part of the economic evaluation."[434] ETI never modeled the OCAPS operations with an alternative hydrogen fuel.[435] Thus, Cities argue that customers should not be required to front the cost and then for succeeding decades, pay a return on a $91 million payment for infrastructure that may never provide benefits. Cities also maintain that ETI should wait until hydrogen does become cost-competitive to evaluate the cost and benefits of adding hydrogen-capable infrastructure at that time.[436]

Regarding reliability, Cities argue that ETI already has the equivalent of a dual fuel capability through the Spindletop facility.[437] Cities assert that the

[430] TIEC Ex. 1B at Bates 017 (Griffey Dir., WP); TIEC Ex. 1 (Griffey Dir.) at 98.

[431] Cities Ex. 1 (O'Donnell Dir.) at 16–17.

[432] ETI Ex. 13 (Hebner Dir.) at 5-6.

[433] ETI Ex. 13 (Hebner Dir.) at 6; ETI Ex. 19 (Hebner Reb.) at 4-5; Tr. at 450 (Hebner Cross).

[434] Tr. at 338–39 (Nguyen Cross).

[435] Cities Ex. 4 (ETI response to Cities RFI No. 1-6).

[436] Cities Initial Brief at 21.

additional reliability that hydrogen would add to the storage capability at Spindletop, which has never failed in its back-up capability, is not necessary given the additional cost and risk of stranded cost if hydrogen does not become economic.

B. Logistics for Fueling by Hydrogen (P.O. Issue Nos. 37-38, 40-47)

1. ETI's Position

ETI states that it is working with local hydrogen suppliers in the area and that it would have access to locally stored hydrogen. It maintains that the Texas-Louisiana Gulf Coast claims the nation's most extensive hydrogen pipeline network, with three major hydrogen pipelines (nearly 440 miles) within several miles of the OCAPS site.[438] As such, ETI would only need to construct a feeder to interconnect with any of these pipelines to access hydrogen. Moreover, ETI points out that Linde—a TIEC participating member in this case—added a hydrogen production facility in Texas in 2021 with a capacity of 1.5 billion cubic feet per day and that other major hydrogen projects have been announced for the Gulf Coast region.[439]

ETI also argues that although the predominant method of hydrogen production in Texas today is through extraction from natural gas, short-term

[437] Tr. at 340 (Nguyen Cross).

[438] ETI Ex. 13 (Hebner Dir.) at 7-8, 18-20; ETI Ex. 27A (Ruiz Reb.) at 5.

[439] ETI Ex. 19 (Hebner Reb.) at 1-3, 7; ETI Ex. 19A (Hebner Reb., WP), REH WP FN2 (Bates 3-4).

supply disruptions for natural gas would not affect its stored hydrogen supply.[440] ETI states that three of the four underground hydrogen storage facilities in operation today are located in Texas, and two are located near the Sabine Power Station where OCAPS will be located.[441] Additionally, ETI has the ability to use a third storage cavern at the Spindletop site, which is already interconnected to the Sabine site.[442]

2. Staff's Position

Staff expresses concerns about the comparative cost of the hydrogen capability infrastructure needed. Staff points out that ETI estimates the proposed hydrogen gas pipeline would cost $4 million to construct,[443] compared to the estimated $550,000 to modify the existing natural gas pipelines to tie into OCAPS.[444] Additionally, due to the blending of natural gas and hydrogen, a fuel compressor costing $15 million would need to be constructed off of the hydrogen gas pipeline when it reaches OCAPS to enable the co-firing capability.[445] Staff witness Ms. Ghanem opined that more costly measures would be needed to control leakage because hydrogen is more permeable than natural gas and causes steel embrittlement.[446] Also, hydrogen's lower energy density would require that it be

[440] ETI Closing Brief at 77.

[441] ETI Ex. 19 (Hebner Reb.) at 8-9, 18-19; ETI Ex. 27A (Ruiz Reb.) at 5.

[442] ETI Ex. 19 (Hebner Reb.) at 19; ETI Ex. 27A (Ruiz Reb.) at 5.

[443] Staff Ex. 8 at 15 (Bates 3) (ETI responses to Staff RFI No. 1-7).

[444] Staff Ex. 8 at 16 (Bates 4) (ETI responses to Staff RFI No. 1-7).

[445] Staff Ex. 7 at 13 (Bates 2) (ETI responses to Staff RFI No. 1-6).

[446] Staff Ex. 1 (Ghanem Dir.) at 13.

recompressed multiple times through the length of the pipeline since the hydrogen loses pressure at a relatively high rate as it is transported.[447]

C. Analysis

The ALJs find that ETI has not demonstrated that the proposed hydrogen co-firing capability is a necessary component to OCAPS. First, it is not currently cost competitive with natural gas, and the date by which it will be depends upon technology not yet in existence. ETI maintains that hydrogen will be cost-competitive in the foreseeable future, but that estimate is speculative. Dr. Hebner's estimate of this timeline ranged from two years to two decades. The ALJs understand that the Texas Gulf Coast region provides extensive hydrogen infrastructure and boasts a mature hydrogen economy; however, the economic viability of hydrogen firing is uncertain at this time.[448]

In addition, the costs of using gray hydrogen—the form that will be initially used—are significant. According to ETI, the average price for gray hydrogen is more than double the cost of burning the equivalent of natural gas alone. Hydrogen dual-firing capability would require investment in a hydrogen gas pipeline (costing approximately $3.45 million more than modifying the existing natural gas pipelines to tie in OCAPS), a $15 million fuel compressor, leakage control measures, and recompression efforts.

[447] Staff Ex. 1 (Ghanem Dir.) at 13.

[448] *But see* Inflation Reduction Act of 2022, § 13204 (Clean Hydrogen).

The ALJs also find that the potential benefits of hydrogen capability cannot be properly analyzed because ETI failed to provide any economic analysis including the costs of burning hydrogen or any forecast for hydrogen prices.

Moreover, the ALJs find that the uncertainty and unpredictability relating to OCAPS' hydrogen capability extend to ETI's assertion regarding the potential conversion of OCAPS to 100% hydrogen capability. ETI asserts that the initial investment would lead to shorter conversion cost and outage duration for a 100% hydrogen firing OCAPS facility. However, the timeline for this conversion, let alone the realization of it, is uncertain. Significantly, the added cost to consumers for hydrogen capability, which will accrue immediately, may not be realized for decades, if ever.

Under PURA section 37.056(c)(4)(E), the Commission must consider "the probable improvement of service or lowering of cost to consumers in the area if the certificate is granted, *including any potential economic or reliability benefits associated with dual fuel and fuel storage capabilities in areas outside the ERCOT power region.*" (emphasis added). Although it is undisputed that hydrogen capability would provide increased reliability benefits in the event that natural gas supply is constrained, this must be considered in light of the probable improvement of service or lowering of cost—both in terms of money and environmental impact. OCAPS will be located in close proximity to ETI's Spindletop facility, which provides substantial natural gas storage. Moreover, there is no evidence of any inadequacies regarding Spindletop's capability. This fact significantly weighs against need for further reliability. Notably, ETI asserted that the hydrogen co-firing capability would *only* be used for reliability purposes until hydrogen is cost-competitive with natural gas.

Furthermore, according to ETI's above-referenced estimate, gray hydrogen would produce substantially more carbon emissions than natural gas alone—an environmental concern that cannot be ignored.[449] The high cost of green hydrogen makes it unlikely to be used for the foreseeable future.

In sum, the ALJs conclude that the initial investment costs as well as current operational costs, the uncertainty regarding OCAPS' ultimate conversion status and possible hydrogen-capability benefits, OCAPS' access to Spindletop's natural gas supply, and the potential environmental impacts outweigh the need for the proposed hydrogen-capability at this time.

IX. THE PROBABLE IMPROVEMENT OF SERVICE OR LOWERING OF COST TO CONSUMERS IN THE AREA IF THE CERTIFICATE IS GRANTED

A. Reliability (P.O. Issue Nos. 29-34)

No party disputes that OCAPS would probably improve service to customers in the area if the certificate is granted by enhancing reliability. The following reliability benefits are uncontested.

Locating OCAPS in close proximity to an industrial load center in Southeast Texas will reduce dependence on existing transmission infrastructure, reduce

[449] Staff Ex. 17 at 2 (ETI responses to Staff RFI No. 6-1).

transmission losses, and address the critical need for reactive power support required for transmission system reliability.[450]

Placing OCAPS at the existing Sabine site will maintain regional operational flexibility as the Sabine units are removed from service and add locational diversity of highly efficient CCCT technology through its placement between MCPS and Lake Charles Power Station.[451] The ability of OCAPS to access natural gas stored at ETI's Spindletop facility is an additional reliability benefit in times of constrained natural gas supply.[452]

OCAPS will help maintain transmission system inertia and dynamic reactive support within ETI's Eastern Region and provide critical in-region capacity to maintain service and facilitate more rapid system restoration following major storms.[453] Locating OCAPS within ETI's Eastern Region will help ETI avoid the need to overcome transmission constraints based on geographic challenges.[454] This in turn will provide important system-restoration benefits during major storm events, such as Hurricane Laura and Winter Storm Uri.[455]

[450] ETI Ex. 5 (Kline Dir.) at 4-6, 8-10); *see also* ETI Ex. 4 (Weaver Dir.) at 5-6.

[451] ETI Ex. 4 (Weaver Dir.) at 6.

[452] ETI Ex. 29 (Weaver Reb.)at 55; *see also* OPUC Ex. 1 (Nalepa Dir.) at 25.

[453] ETI Ex. 4 (Weaver Dir.) at 6; ETI Ex. 5 (Kline Dir.) at 8.

[454] ETI Ex. 5 (Kline Dir.) at 4-5, 7.

[455] ETI Ex. 5 (Kline Dir.) at 12; ETI Ex. 21 (Kline Reb.) at 7.

ETI further notes that simply replacing its aging generators while meeting projected load growth will enhance reliability, given the age and condition of Sabine 4, as discussed above.

Additionally, Mr. Kline testified that, because MISO regularly commits Sabine 1, 3, and 4 to address VLR issues,[456] if they are not replaced, MISO will either lack units to commit to address those concerns or be required to dispatch other higher cost and likely less reliable units to address those concerns.[457] Either way, without OCAPS, there will be a negative impact on service reliability in the Eastern Region.[458]

Both TIEC and Sierra Club repeat many of the arguments they raise elsewhere, regarding whether other options could address VLR issues in the Eastern Region, whether ETI properly assumed the retirement of Sabine 4 in 2026, or whether other resources could provide similar benefits.[459] Those arguments are addressed elsewhere in the PFD and, in any event, do not negate the reliability benefits of the proposed project.

Staff recommended that OCAPS be weatherized to withstand conditions as severe as Winter Storm Uri.[460] In response, ETI included additional weatherization measures for this project to ensure OCAPS is designed to operate in conditions

[456] ETI Ex. 21 (Kline Reb.) at 11; ETI Ex. 26 (Owens Reb.) at 2-3, 12-13.

[457] ETI Ex. 21 (Kline Reb.) at 11.

[458] ETI Ex. 21 (Kline Reb.) at 11.

[459] Sierra Club Ex. 11.

[460] Staff Ex. 1 (Ghanem Dir.) at 4.

such as those experienced during Winter Storm Uri and other extreme weather events.[461]

For the above reasons identified by ETI, the ALJs find that OCAPS would result in a significant improvement of service to ETI customers.

B. Economic Evaluation (P.O. Issue Nos. 19, 22)

ETI contends that OCAPS is an economic resource option that will lower the cost of service to ETI's customers, as shown in its 2019 Portfolio Analysis and subsequent economic evaluations.

Mr. Nguyen testified that the economics of OCAPS was initially evaluated in response to the 2020 RFP by ETI's Economic Evaluation Team.[462] This evaluation estimated the total project cost to be $1.12 billion.[463] After the RFP, the Economic Evaluation was updated to account for the decision to invest $65 million in plant infrastructure to use the hydrogen co-firing capability of the turbines and the latest transmission cost estimates.[464] With these updates, Mr. Nguyen arrived on the $1.19 billion projected cost of OCAPS, which he then compared to an equivalent amount of long-term capacity from three combustion turbines (CTs) (i.e., the three

[461] ETI Ex. 8 (Ruiz Dir.) at 8-10; ETI Ex. 27 (Ruiz Reb.) at 9.

[462] ETI Ex. 7 (Nguyen Dir.) at 13-20; ETI Ex. 4A (Weaver Dir., Conf.), Exh. ABW-8 at 9 of 11.

[463] ETI Ex. 7 (Nguyen Dir.) at 19, Exh. PDN-2 (HSPM); ETI Ex. 4A (Weaver Dir., Conf.), Exh. ABW-8 at 7 of 11.

[464] ETI Ex. 7 (Nguyen Dir.) at 23-24.

CT case previously referenced in the PFD).[465] Mr. Nguyen determined the net benefit of OCAPS to be $1.85 billion.[466]

Table 2: Results of Updated[467] Economic Evaluation

	Reference Gas; Reference CO2	Low Gas; Low CO2	High Gas; High CO2
Net Benefit Present Value [2021$Ml[468]	**$1,848.9**	$1,313.1	$2,803.8
Customer Commitment Breakeven Year[469]	2036	2038	2033
First-Year Fuel Savings	$108.6	$90.6	$204.7

In rebuttal testimony, Mr. Nguyen again updated his evaluation to reflect the most recent project cost estimate of $1.37 billion and updated cost estimates for the three CTs.[470] That update showed a net savings of $1.7 billion:[471]

Table 3: Results of Updated Economics

	Reference Gas; Reference CO2	**Low Gas; Low CO2**	**High Gas; High CO2**
Net Benefit Present Value [2021$Ml	**$1,757**	$1,236	$2,726

[465] ETI Ex. 7 (Nguyen Dir.) at 15.

[466] ETI Ex. 7 (Nguyen Dir.) at 25.

[467] ETI Ex. 7 (Nguyen Dir.) at 25.

[468] The ALJs assume this notation refers to millions of dollars in at the value in year 2021.

[469] Breakeven Year assumes OCAPS compared to the levelized real cost of the three CT alternative. Comparing OCAPS to the actual, nominal cost of the three CT alternative would result in an even earlier breakeven year of 2026 (year 1) in the reference case.

[470] ETI Ex. 25 (Nguyen Reb.) at 2.

[471] ETI Ex. 25 (Nguyen Reb.) at 2.

Additionally, in response to intervenor testimony, Mr. Nguyen performed a sensitivity analysis for this Updated Economic Evaluation wherein he made several adjustments to eliminate the effect of comparing the generic fixed cost data for these resources to the unit-specific fixed cost assumptions for OCAPS and adjusted the CT capital cost to be lower than OCAPS.[472] The result showed a benefit of $1.5 billion:[473]

Table 4: Sensitivity Results - Updated Economics with Lower CT Cost

	Reference Gas; Reference CO2	**Low Gas; Low CO2**	**High Gas; High CO2**
Net Benefit Present Value [2021$Ml	$1,589	$1,068	$2,559

These analyses, ETI argues, show that OCAPS will provide significant net benefits across the Low, Reference, and High Gas cases.[474] There is no more recent analysis to reflect the June cost estimate of $1.58 billion; however, ETI argues that these analyses show that project cost escalations have an effect of less than 1:0.5 on net benefits, thereby reducing the benefits by less than half the amount of any increase.

TIEC, Sierra Club, and OPUC argue that ETI's economic analysis failed to provide a meaningful comparison to OCAPS and is based on several flawed assumptions.

[472] ETI Ex. 25 (Nguyen Reb.) at 2-3.

[473] ETI Ex. 25 (Nguyen Reb.) at 3.

[474] ETI Ex. 25 (Nguyen Reb.) at 2; TIEC Ex. 1 (Griffey Dir.) at 57-58 (criticizing the high capital cost of the three CTs ($1,032/kW compared to the capital cost of OCAPS ($956/kW))).

1. The Three CT Comparison

TIEC argues that the three CT to which OCAPS was compared are unrealistic because ETI admits that they are not an economic resource or one that would meet its needs.[475] Mr. Griffey testified that "any of the four portfolios ETI rejected as uneconomical in ETI's 2019 Portfolio Analysis would be shown as providing massive benefits" compared to ETI's "unrealistic" three CT alternative.[476] TIEC and Sierra Club argue that ETI should not have compared OCAPS to the cost of building three CTs because it is not a resource the Company would ever have chosen. TIEC argues that it was unreasonable to compare OCAPS with constructing three large and inefficient hydrogen-enabled CTs that have higher capital costs per kW than a hydrogen-enabled CCGT to show OCAPS was less expensive.

ETI argues that the purpose of the Economic Evaluation was not to compare OCAPS to an option ETI would consider to serve load, which the 2019 Portfolio Analysis and RFP did.[477] Rather, the purpose of the Economic Evaluation was to show whether OCAPS can be expected to confer benefits to customers relative to taking the least-cost alternative action to address that capacity need.[478] Mr. Griffey testified that CTs are relatively inefficient, having a higher heat rate and therefore high fuel cost, but lower capital costs.[479] Similarly, Mr. Nguyen testified that a CT

[475] Tr. at 414 (Nguyen Redir.); ETI Ex. 25 (Nguyen Reb.) at 33-34.

[476] TIEC Ex. 1 (Griffey Dir.) at 57.

[477] Tr. at 414-15 (Nguyen Redir.).

[478] ETI Ex. 25 (Nguyen Reb.) at 32-34; Tr. at 380-81, 409-10 (Nguyen Cross); Tr. at 414-415 (Nguyen Redir.).

[479] TIEC Ex. 1 (Griffey Dir.) at 57-58.

sited to address locational needs is ETI's lowest reasonable cost option for long-term capacity and that "CTs are commonly considered in the industry as representative of the cost of new entry for capacity and therefore a reasonable reference point for comparison to OCAPS."[480] The cost of new entry (CONE) is considered by MISO to be the levelized cost of a generic CT.[481] Thus, for long-term resources, an estimate of ETI's cost to install a CT shows the avoided cost of capacity.[482]

The ALJs agree with ETI that the assessment of the avoided cost is distinct from selecting the best resource to meet a particular need. This would be true of any new technology. The benefit of new technology lies in replacing outdated, if cheaper, alternatives. If the new technology is compared only to itself or more efficient technology, no plant would ever show a benefit. Moreover, the Economic Evaluation need not compare the target resource only to resources that the company would consider using, as not all resources will serve its need, but may nevertheless result in cost benefits. The ALJs find that ETI reasonably evaluated the avoided costs of OCAPS against three CTs.

2. Capital Costs

TIEC argues that the Economic Evaluation unreasonably assumed that the cost per kW for a CT is greater than the cost per kW of OCAPS. OCAPS would be

[480] ETI Ex. 25 (Nguyen Reb.) at 32; Tr. at 380-381, 409 (Nguyen Cross), 414-415 (Nguyen Redir.); ETI Ex. 7 (Nguyen Dir.) at 24.

[481] ETI Ex. 12 (Owens Dir.) at 7; TIEC Ex. 1 (Griffey Dir.) at 81 ("MISO's CONE[] is based on the capital cost of a new CT.").

[482] ETI Ex. 7 (Nguyen Dir.) at 15; ETI Ex. 12 (Owens Dir.) at 20-21.

an efficient (low heat rate) base load plant that would operate 80% to 90% of the time.[483] By contrast, the three CTs used for a comparison are inefficient (high heat rate) plants that would operate only small percentage of the time.[484] TIEC points out that Mr. Nguyen's assumed cost of the CTs on a per kilowatt basis ($1,032/kW)[485] is more than his estimate of the cost of OCAPS ($956/kW)[486] and significantly more than the cost of a CT in Texas used by MISO to set the CONE in its most recent PRA ($676/kW).[487]

ETI asserts that the per kilowatt installed cost of a CT used by ETI exceeds the unit cost for MISO's CONE because they account for install dates. Mr. Owens explained that TIEC relies on MISO's most recent quantification of CONE for the 2022/2023 planning year, which assumes a resource entering service in 2022, and does not reflect the recent cost escalation.[488] Therefore, the CONE in 2022 is materially lower than the CONE in 2026.[489] Given the cost escalations shown in the rebuttal testimony of Mr. Ruiz, Mr. Nguyen updated his economic analysis to account for the higher fixed cost for the three CT alternative at a commensurate level (see Table 4, above).[490]

[483] Tr. at 373 (Nguyen Cross, Conf.).

[484] Tr. at 368-69 (Nguyen Cross, Conf.); TIEC Ex. 1 (Griffey Dir.) at 80 (HSPM).

[485] TIEC Ex. 1 (Griffey Dir.) at 57. Although this number is treated as confidential in this part of TIEC's brief and discussed in a confidential portion of the hearing (Tr. at 368 (Nguyen Cross, Conf.), it appears without objection publicly both the cited portion of Charles Griffey's testimony and on page 8 of TIEC's Initial Brief. The ALJs therefore find that ETI waived any claim to confidentiality of this number.

[486] Tr. at 366-69 (Nguyen Cross).

[487] TIEC Ex. 65 at 9 (MISO Local Resource Zone CONE calculation, October 2021).

[488] Tr. at 531-33 (Owens Cross); TIEC Ex. 65 at 8.

[489] Tr. at 540-41 (Owens Redir.).

[490] ETI Ex. 25 (Nguyen Reb.) at 2.

The ALJs find that it was not appropriate to assume that the CTs would operate only as peaker plants while assuming OCAPS would serve baseload. Rather, for a fair comparison, the CTs should have been assumed to run the same amount of time as OCAPS. ETI has provided no explanation for this treatment and there are no apparent reasons for it. It is unclear, however, what impact, if any, this assumption alone had on the analysis.

However, the ALJs find that the assumption that the CTs would operate at a less efficient heat rate was reasonable because the evidence shows CTs represent the less efficient alternative that OCAPS would replace. The ALJs agree that it was appropriate for ETI to account for placing the CTs in service in 2026 as opposed to 2022 to more accurately account for market escalation, as it did with OCAPS. As ETI points out, even applying the 41% escalation factor for OCAPS, cited by TIEC,[491] to the most recent MISO CONE yields a value of $953/kW ($676/kW x 41%), which is more in line with the 2026 unit costs for the CTs ($1,032/kW) and OCAPS ($956/KW).[492] Therefore, ETI's cost per kW is consistent with TIEC's cost estimate calculation. Moreover, Mr. Nguyen's sensitivity analysis (Table 4, above) made the capital cost of the CTs lower than OCAPS and continued to show benefits.

[491] TIEC Initial Brief at 22 (calculating the market escalation costs of OCAPS in at ETI's board approval level in June ($1.68 billion) to be 41% higher than ETI's initial forecast ($1.19 billion)); *see also* OPUC Ex. 1 (Nalepa Dir.) at 12.

[492] TIEC Initial Brief at 26.

3. Fixed Costs

TIEC and Sierra Club further fault Mr. Nguyen's analysis (Table 2, above) for a number of fixed costs assumptions. First, the argue that it was wrong to add hydrogen capability to peaker plants that will only operate for a limited number of the hours in a year, without any economic analysis of whether doing so would make sense, or even knowing if anyone had ever decided to add hydrogen capability to a CT.[493]

ETI responds that the adjustments to the cost of the CTs was done to achieve an apples-to-apples comparison. Mr. Nguyen testified that most turbines built today are, like OCAPS, capable of burning hydrogen-blended fuels.[494] Mr. Nguyen testified that it was reasonable to assume that ETI would make the same reliability and sustainability decisions to make use of that capability.[495]

Next, Mr. Griffey testified that ETI inflated the cost of the three CT option in other ways. First, Mr. Griffey testified that ETI assumes that the three CTs would have fixed operation and maintenance (O&M) costs of more than double the cost-per kW-year assumption in its generic assumption for a CT in the portfolio analysis.[496] Similarly, ETI has more than doubled the fixed fuel demand charge attributable to a CT from what it assumed in its 2019 analysis.[497]

[493] Tr. at 364-66 (Nguyen Cross, Conf.); TIEC Ex. 1 (Griffey Dir.) at 80.

[494] ETI Ex. 25 (Nguyen Reb.) at 33.

[495] ETI Ex. 25 (Nguyen Reb.) at 33-34.

[496] TIEC Ex. 1A (Griffey Dir., Conf.) at 59.

[497] TIEC Ex. 1 (Griffey Dir.) at 59.

Third, ETI improperly assumed that the three CTs would have roughly the same interconnection costs, despite the fact that they can be sited much closer to existing transmission. Sierra Club makes similar arguments.

Mr. Nguyen responded that he assumed a fixed fuel demand charge for the three CTs because ETI would need a firm fuel commitment similar to OCAPS so that the avoided capacity is comparable from a reliability standpoint.[498] With respect to the variable O&M costs, Mr. Nguyen testified that the fixed O&M cost increased based on updated information but that "the variance does not meaningfully impact the results of the economic analysis."[499] Regarding the transmission interconnection and upgrade cost assumptions, Mr. Nguyen testified that the cost estimates are based on site-specific transmission upgrades, but did not provide a further explanation.[500] However, ETI argues that the three CTs cannot logically all be located at the Sabine Power Station.

ETI further argues that Mr. Nguyen's sensitivity analysis removed the effects of those adjustments, and OCAPS, which addresses both capacity and energy needs, is still more economic than simply taking the limited step of addressing only the Company's capacity need.[501]

The ALJs find that it was not reasonable to assume a hydrogen component for the CTs. There is no evidence that MISO's CT/CONE measure includes

[498] ETI Ex. 25 (Nguyen Reb.) at 35.

[499] ETI Ex. 25 (Nguyen Reb.) at 36.

[500] ETI Ex. 25 (Nguyen Reb.) at 36.

[501] ETI Ex. 25 (Nguyen Reb.) at 2-3.

hydrogen capability or that a hydrogen-enabled CT is the lowest cost alternative. Similarly, the ALJs find the fixed O&M and interconnection costs unsupported. However, the ALJs find that the comparable fixed fuel demand charge is reasonable because such a charge would be necessary to ensure an adequate source of fuel. It is unclear, however, what impact, if any, such adjustments had on the savings analysis, given that Mr. Nguyen's sensitivity analysis removed them (see Table 4, above).

4. OCAPS Assumptions

TIEC argues that ETI conversely understated the cost of OCAPS. First, TIEC asserts that ETI understated the cost of capital associated with OCAPS. In analyzing the future costs and benefits of OCAPS, Mr. Nguyen assumed cost of debt through 2056 of 3.53%,[502] and a cost of equity of 9.65% to yield a discount rate of 6.03%.[503] TIEC argues that the debt costs are increasing and this cost of debt makes OCAPS appear more economic.

TIEC further argues that ETI failed to account for the possibility that OCAPS may be retired early to comply with ETI's commitment to be net zero in carbon emissions by 2050.[504] Mr. Nguyen modeled OCAPS burning natural gas

[502] ETI Ex. 7A (Nguyen Dir.), 52487 Nguyen WP3_Exhibit PDN-3 OCAPS Economic Eval Model Low Gas No CO2_HSPM, Assumptions tab.

[503] Tr. at 359-60 (Nguyen Cross, Conf.).

[504] TIEC Ex. 30 (Entergy Press Release) (Sept. 24, 2020) ("Entergy Corporation . . . announced today it is accelerating its climate action goals with a commitment to achieving net-zero carbon emissions by 2050.").

after 2050,[505] accounting for more than $1 billion dollars (nominal) of the economic benefit of OCAPS.[506]

Finally, TIEC repeats its argument that the estimate is out of date and ETI failed to re-evaluate the portfolios as suggested by a draft PowerPoint presentation in April 2021. These arguments are addressed above.

Regarding the suggestion that OCAPS will be retired early to achieve net zero carbon emission commitments by 2050,[507] ETI argues that this ignores the alternatives of obtaining credits to offset the effects of carbon emitting resources and the potential that hydrogen-burning capability of OCAPS will become more economic by that time.[508]

Although ETI's assumed cost of debt may be low, the evidence does not show that it made a material difference, and TIEC offered no basis for disregarding it as a place-holder for planning purposes in this case. The undisputed cost increases for OCAPS (to date) have been demonstrated to decrease the net benefits of the project, but not eliminate them (see Tables 3 and 4, above). Although a similar demonstration has not been made beyond ETI's rebuttal testimony, and continued cost escalations are certain to further erode those net benefits, the ALJs

[505] See Tr. at 69-70 (Viamontes Cross).

[506] ETI Ex. 7A (Nguyen Dir.), 52487 Nguyen WP3_Exhibit PDN-3 OCAPS Economic Eval Model Low Gas No CO2_HSPM at Net Benefits Calculations tab, Columns 2050 through 2056.

[507] TIEC Initial Brief at 28-29.

[508] Tr. at 70 (Viamontes Cross).

do not find the OCAPS cost assumptions discussed here to be materially understated.

Additionally, TIEC's suggestion that OCAPS might be retired early to meet ETI's net zero commitment by 2050 is not persuasive. *Net* zero is not the same as zero, and ETI has advanced reasonable suggestions as to how OCAPS may continue to burn gas while meeting that commitment.[509]

The ALJs address the lack of analysis beyond ETI's rebuttal testimony below.

5. Additional Concerns in the Economic Evaluation

TIEC argues that the Economic Evaluation was further faulty for overstating OCAPS' capacity factors, power price projections, natural gas prices, a carbon tax assumption, post-hoc O&M adjustment, and capacity value.

a) Renewables and Technological Improvements

In Docket No. 51215, the Commission found that "Entergy's assumptions regarding the future generation mix in MISO South do not account for the likelihood that additional renewable generation and technological improvements will result in lower power prices."[510] TIEC argues that ETI made the same error here, affecting both OCAP's capacity factors and its purchase price projections.

[509] TIEC Ex. 30 at 3 (Entergy explains that its commitment strategy includes "continuing investment in . . . modern, efficient natural gas generating units," while retiring coal and older, less efficient gas-powered units.).

[510] Docket No. 51215, Final Order at 13 (FoF 107) (Oct. 19, 2021).

Additionally, TIEC argues that given the Entergy goal of achieving net-zero carbon by 2050,[511] it is likely that MISO South will see additional renewable penetration beyond 2040 that will likewise drive down OCAPS' energy savings.

(i) Capacity Factors

TIEC and Sierra Club argue that the Economic Evaluation overstates OCAPS' capacity factors by failing to properly model technological advancements that drive down the cost of power.

ETI forecasts that OCAPS would operate throughout its life at a high capacity factor.[512] Sierra Club witness Glick testified that ETI improperly assumed that the three CTs would operate at a low capacity factor while OCAPS would operate at a high capacity factor.[513] Ms. Glick further testified that it is unlikely that even a new CCGT plant will operate at a level that high based on both (1) historical data on combined cycle unit operations, and (2) increasing penetration of zero variable cost wind and renewables onto the grid, which will increasingly push fossil resources out of the dispatch stack.[514]

Mr. Griffey similarly attributes ETI's overly optimistic capacity factor assumptions, as its MCPS application projections turned out to be, to ETI's failure

[511] TIEC Ex. 30 (Entergy Press Release, Sept. 4, 2020).

[512] TIEC Ex. 1A (Griffey Dir., Conf.) at 62 (Bates 28), Fig. 14.

[513] Sierra Club Ex. 1 (Glick Dir.) at 38.

[514] Sierra Club Ex. 1 (Glick Dir.) at 38.

to account for advances in technology.[515] Additionally, Mr. Griffey testified that ETI assumes that the heat rate of every CCGT installed in MISO South after OCAPS begins operation would have a worse heat rate than OCAPS.[516] None of these assumptions are reasonable, TIEC argues, given the near certainty of technological advances that will occur over the next 30 years. Increased penetration of solar and wind will either displace CCGT operating hours (decreasing OCAPS' capacity factor) or put more efficient units on the margin (decreasing projected energy cost savings).[517]

Ms. Weaver explained that the high projected capacity factor, even from the 2030s to the 2050s, was the result of the "level of need that we have for a resource that is as economic as it is and is capable of producing as much energy as it is in a region that's constrained with a lot of demand."[518] Mr. Nguyen testified that his analysis accounted for advances in new technology that could affect the market price for energy. He further testified that the production cost model used to evaluate OCAPS is programmed to assume that any new generation added to the market to serve load is the most modern, proven technology. These future market build assumptions include a mix of solar, wind, CT, and CCCT resource additions with operating characteristics consistent with the technology improvements identified

[515] TIEC Ex. 1A (Griffey Dir., Conf.) at 60-61; Tr. at 131-32, 163 (Weaver Cross, Conf.); TIEC Ex. 33 at TP-52487-00TIE003- X004_HSPM MCPS (HSPM) (ETI response to TIEC RFI No. 3-4); TIEC Ex. 34 (ETI response to TIEC RFI No. 3-1).

[516] TIEC Ex. 1 (Griffey Dir.) at 61-62, 64.

[517] TIEC Ex. 1 (Griffey Dir.) at 60.

[518] TIEC Ex. 1A (Griffey Dir., Conf.) at 60; Tr. at 108 (Weaver Cross).

through technology assessment.[519] According to Mr. Nguyen, that assumption causes OCAPS to compete with those modern resources to sell energy into the market.[520]

Mr. Nguyen noted that OCAPS will operate in a load pocket and therefore may be selected for commitment and dispatch of MISO to satisfy local reliability needs.[521] Mr. Nguyen further testified that there are no forecasts for unproven generation efficiency improvements that could be used as an input to the model.[522] There is no reasonable basis to quantify whether or how not-yet-developed generation technologies may affect those benefits.[523] All current generation will eventually have to compete with future generation technology.[524]

With respect to future CCGT additions, Mr. Nguyen testified that variation in heat rates achieved among a class of CCCT units may be attributed to unit specific differences, location, or fuel prices that result in operational differences, which may affect the calculated heat rates.[525]

Thus, ETI argues that it reasonably assumed that any future technology advancements will not eliminate all benefits expected from OCAPS. ETI points out that the breakeven analysis shows that OCAPS will pay for itself when the capacity and energy savings produced by OCAPS can be expected to offset the present value

[519] ETI Ex. 25 (Nguyen Reb.) at 41.

[520] ETI Ex. 25 (Nguyen Reb.) at 41-42.

[521] ETI Ex. 25 (Nguyen Reb.) at 42.

[522] ETI Ex. 25 (Nguyen Reb.) at 44.

[523] ETI Ex. 25 (Nguyen Reb.) at 44.

[524] ETI Ex. 25 (Nguyen Reb.) at 41-43.

[525] ETI Ex. 25 (Nguyen Reb.) at 43.

of the fixed costs for the unit: within roughly 12 years under the Low Gas case, and within 8-10 years under the High or Reference Gas cases.[526]

The ALJs agree with TIEC that advances in technology are a near certainty over the next 30 years, particularly in light of the IRA[527] and Entergy's own net zero emissions commitment, with which all new resources will someday have to compete.

The evidence further shows that ETI's modeling accounted for technological advances to the extent known, and no third-party projections exist to quantify additional technological advances. Additionally, OCAPS' location in a load pocket with significant demand may favor its selection for commitment and dispatch by MISO to satisfy local reliability needs.[528] There is no evidence that the market might similarly favors MCPS.

Therefore, the ALJs find that ETI reasonably assumed a high capacity factor based on known technological advancements. Moreover, the ALJs agree that any reduction in capacity factor resulting from competition with other resources is not likely to eliminate all of the benefits expected from OCAPS.

[526] ETI Ex. 7 (Nguyen Dir.) at 25.

[527] *See* Inflation Reduction Act of 2022, §§ 13101, 13102, 13701, 13702.

[528] ETI Ex. 25 (Nguyen Reb.) at 42.

(ii) Power Price Projections

TIEC notes that ETI assumes that OCAPS' heat rate advantage relative to other resources in the market will increase through 2040 and then remain flat from 2040 through 2056.[529] Mr. Griffey testified that increasing the implied-heat-rate savings must be due to an assumption that, on average, higher marginal cost units are added to the market over time.[530] However, because of technological improvements, lower marginal cost units are added over time.[531] According to Mr. Griffey's analysis, freezing OCAPS' heat-rate advantage at the 2027 level would reduce the variable supply cost savings by 22% in the Reference Gas case and 40% in the Low Gas case.[532]

In response, Mr. Nguyen explained the model results as follows:

> The MISO market build assumptions are in fact based on a forecast of the solar and wind resource additions from an independent third-party consultant augmented with CCCT additions when capacity and energy is needed and CT additions when only capacity is needed to meet target capacity reserve margins and the market energy needs. The addition of solar and wind resources results in energy prices that are lower than those that would result without their addition; however, these resources generally do not set the market clearing price. The market clearing price is set by the highest cost generating unit operating in that hour.[533]

[529] TIEC Ex. 1A (Griffey Dir., Conf.) at 64-65 (Bates 030-031).

[530] TIEC Ex. 1A (Griffey Dir., Conf.) at 65 (Bates 031).

[531] TIEC Ex. 1A (Griffey Dir., Conf.) at 66 (Bates 032).

[532] TIEC Ex. 1 (Griffey Dir.) at 66; *see* ETI Ex. 7A (Nguyen Dir.), 52487 Nguyen WPl_Exhibit PDN-3 OCAPS Economic Eval Model Ref Gas Ref CO2_HSPM at Net Benefits Calculations tab; ETI Ex. 7A, 52487 Nguyen WP3 Exh. PDN-3 OCAPS Economic Eval Model Low Gas No CO2 HSPM at Net Benefits Calculations tab.

[533] ETI Ex. 25 (Nguyen Reb.) at 43.

ETI argues that its model relies on the most recent generation technologies when adding resources, but less efficient resources such as MCPS, the Lake Charles Power Station, and the J. Wayne Leonard Power Station will still be in service.[534] They will set the market clearing price because they operate at a higher cost than OCAPS and renewable resources.[535] Thus, ETI argues, it is reasonable to forecast that OCAPS will maintain a heat rate advantage over those and other existing thermal resources over the study period. ETI notes that two of the futures evaluated in the 2019 Portfolio Analysis included additional solar resources and the results showed the 2x1 CCCT as even more economic compared to the other alternatives.[536]

For the reasons given by ETI, the ALJs find that ETI reasonably modeled purchase price projections and reasonably assumed a heat rate advantage over thermal resources.

b) Natural Gas Prices

While acknowledging that natural gas prices have a lower impact on analyzing the benefits of gas resources (one-quarter the impact as compared to a renewable resource, by TIEC's calculation),[537] TIEC argues that natural gas price projections are uncertain because of their high volatility.[538] The Commission

[534] ETI Ex. 25 (Nguyen Reb.) at 42.

[535] ETI Ex. 25 (Nguyen Reb.) at 42; TIEC Ex. 1A (Griffey Dir., Conf.) at 62-63 (Bates 28-29) (St. Charles Power Station in Figures 14 and 15 was renamed J. Wayne Leonard Power Station.).

[536] See ETI Ex. 4 (Weaver Dir.), Exh. ABW-6 at 67, 72 (Bates 157, 162).

[537] TIEC Reply Brief at 39 (declassified); for calculation, *see* TIEC Initial Brief at 33 (HSPM).

[538] *See* Tr. at 105-06 (Weaver Cross), 334 (Nguyen Cross), 437-38 (Hebner Cross); TIEC Ex. 1 (Griffey Dir.) at 102-03.

recently found that "[f]or the last decade, Entergy's past forecasts have significantly overestimated actual natural gas prices, even in the near term."[539] Thus, TIEC argues that ETI's High Gas case is inflated and unreliable.[540]

Because of that volatility, ETI argues that it prudently evaluated a resource across a range of potential future outcomes to fully consider the risks and benefits in each one,[541] as Mr. Griffey did when he was responsible for resource planning at Houston Lighting and Power.[542]

Mr. Nguyen explained that ETI's long-term gas price forecasts are an average of multiple fundamentals-based forecasts developed by well-recognized and established independent subject matter experts from the industry, including IHS, Energy Ventures Analysis, PIRA, Wood Mackenzie, and ABB.[543] Specifically, ETI's forecasts use a 30-day average of New York Mercantile Exchange (NYMEX) futures gas prices for Year 1 of the forecast period. Those prices reflect near-term market expectations. For Years 3-20 of the forecast period, ETI uses an average of the forecasts prepared by the aforementioned third-party consultants. Years 21-30 of the forecast period reflect constant real dollars following Year 20. For Year 2, ETI develops a linear interpolation between Year 1 and Year 3 as a transition between NYMEX futures and the consultants' average. Because NYMEX futures and the consultants' forecasts do not reflect the delivered cost of gas, adders must

[539] Docket No. 51215, Final Order at 11, FoF 86 (Oct. 19, 2021).

[540] *See* Tr. at 519-20 (Griffey Redir.); TIEC Ex. 1 (Griffey Dir.) at 73.

[541] ETI Ex. 25 (Nguyen Reb.) at 18-20.

[542] Tr. at 480 (Griffey Cross).

[543] ETI Ex. 7 (Nguyen Dir.) at 16-17.

be included to capture additional costs such as transportation and taxes to arrive at a forecasted delivered-to-plant cost of natural gas.[544]

ETI's Low and High Gas sensitivity cases are then developed using implied volatilities (e.g., short-term energy outlook) sourced from the United States Energy Information Agency (EIA) to create a distribution around Year 1 NYMEX prices using +/- 0.5 standard deviations from the Reference Gas price. A linear interpolation is again applied to Year 2, followed by the consultants' average for Year 3 through Year 20, then by constant real dollars.[545]

The natural gas prices used in the Economic Evaluation (Table 2, above) and the comparison to Revised Portfolio 5 (Table 3, above) were based on a Henry Hub natural gas price forecast from BP21 developed in December 2020. The 2021 levelized real gas price was $3.57 ($2021) per MMBtu for the Reference Gas case, $2.53 for the Low Gas case, and 5.38 for the High Gas case.[546]

In the 2019 Portfolio Analysis, the natural gas prices were based on a Henry Hub natural gas price forecast from Business Plan 2019 Update developed in early 2019. The 2019 levelized real gas price was $3.59 ($2019) per MMBtu for the reference case, $2.53 for the Low Gas case, and $4.87 for the High Gas case.[547]

[544] ETI Ex. 7 (Nguyen Dir.) at 16-17.

[545] ETI Ex. 7 (Nguyen Dir.) at 17.

[546] ETI Ex. 7A (Nguyen Dir.), Exh. PDN-3 at 7 (Bates 39).

[547] ETI Ex. 4 (Weaver Dir.), Exh. ABW-6 at 39 (Bates 129).

TIEC argues that even if gas prices turn out to be "high," ETI's High Gas case is flawed because in that scenario utilities would shift to renewables, advanced technologies, and energy efficiency, as Mr. Griffey testified.[548] This, in turn, would decrease the hours in which higher heat rate gas plants would be the marginal fuel, thereby lowering energy prices and thus the energy savings that ETI projects in the High Gas case.[549]

Instead, TIEC argues that ETI's Low Gas case is more reasonable because it most closely matches the EIA's lowest case (High Supply), which the Commission has repeatedly found to be the most accurate in recent years.[550]

ETI argues that the very volatility in gas prices, as recent developments have shown, is a reason that the Commission's finding in Docket 51215 regarding low natural gas price forecasts should not be considered precedent. At the time of hearing, then-current gas prices exceeded the High Gas case, and the forward trading on NYMEX was consistent with the Reference Gas case: $5.11/MMBtu for contracts in 2026 (OCAPS in-service year) and $4.63/MMBtu for contracts in 2030.[551] Mr. Nguyen testified that NYMEX natural gas prices are currently in the range of $6 to $7 and have increased since the beginning of the year.[552] However,

[548] TIEC Initial Brief at 34; Tr. at 519-21 (Griffey Redir.); s*ee also* Sierra Club Ex. 1 (Glick Dir.) at 45, Fig. 6-7 (Glick Dir.) (optimized capacity expansion model selecting higher renewables under high gas assumption). The ALJs find Mr. Griffey's testimony in favor of a low gas forecast somewhat inconsistent with his position regarding the certainty of technological advancements and renewable penetration.

[549] TIEC Ex. 1 (Griffey Dir.) at 72-73.

[550] Tr. at 519 (Griffey Redir.); Docket No. 51215, Final Order at 11, FoF 91 (Oct. 19, 2021); Docket No. 49737, Final Order at FoF 52 (Jul. 6, 2020); Docket No. 47461, Final Order at FoF 89 (Aug. 13, 2018).

[551] Tr. at 481-84 (Griffey Cross); ETI Ex. 36 (Henry Hub Natural Gas Futures-Settlements, June 27, 2022).

[552] Tr. at 333 (Nguyen Cross).

Mr. Nguyen testified that industry experts believe gas prices may fall relative to the current High Gas prices over the next several years.[553]

Cities argue in favor of ETI's High Gas forecast. They argue that recent increases in the cost of natural gas supports the Reference Gas case (reaching $6.67 by 2044) and ETI's High Gas case (reaching $8.77 by 2044) as the most reasonable long-run estimates.[554] Cities witness Kevin O'Donnell testified that there is a wide spread in forecasted gas prices because the United States is expected to step up gas production to help European nations to supply their natural gas needs.[555] "Similarly, the forward prices of natural gas are dependent on geopolitical events as well as market forces that are well beyond the control of any entity involved in these proceedings."[556] As such, Cities argue, the higher end of ETI's natural gas price forecasts are the most reasonable.

By contrast, Mr. Griffey testified that in the face of highly uncertain benefits, it is more valuable to delay an investment decision, if possible, until more information about the future becomes known.[557]

TIEC responds that natural gas prices before OCAPS goes into service, including the recent increase in spot prices, do not impact the net benefits of

[553] Tr. at 334 (Nguyen Cross).

[554] Cities Ex. 2 at 4 (Executive Summary, showing ETI's reference, low, and high gas price forecasts by year).

[555] Cities Ex. 1 (O'Donnell Dir.) at 14-15.

[556] Cities Ex. 1 (O'Donnell Dir.) at 15.

[557] *See* TIEC Ex. 1 (Griffey Dir.) at 73.

OCAPS.[558] TIEC notes that NYMEX prices drop to the low $4.00 range in the spring of 2026 and stay under $5.00 the rest of the year, and are even lower the following year.[559]

TIEC further argues that the BP21 Reference Gas case price forecast is unreasonably high. Even ETI's BP22 Reference Gas forecast shows levelized gas prices from 2026 to 2055 that are 18% lower than the BP21 Reference Gas case.[560] The EIA High Supply case is even lower, at $3.90 per MMBtu over the same period.[561]

The ALJs find that ETI properly evaluated natural gas prices across a range of potential future outcomes. Recent events have shown the value of that precaution. Current prices are high and more consistent with ETI's High Gas case but do not impact the net benefits of OCAPS unless in place after 2026. The currently high natural gas prices are expected to fall: as reflected in the NYMEX, prices drop to the low $4.00 range in the spring of 2026 and stay under $5.00 the rest of the year, and are even lower the following year.[562] However, they do not drop below $4.00 for the foreseeable future, making ETI's Reference Gas case through 2034 conservative (even with carbon).[563]

[558] TIEC Reply Brief at 38.

[559] ETI Ex. 36 at 2.

[560] TIEC Ex. 1 (Griffey Dir.) at 69.

[561] *See* TIEC Ex. 1 (Griffey Dir.) at 69.

[562] ETI Ex. 36 at 2.

[563] ETI Ex. 36 at 4; Cities Ex. 2 at 4.

Moreover, the fact that ETI lowered its Reference Gas case from its BP21 to its BP22 does not negate either the uncertainty of natural gas prices or ETI's demonstrated need for a resource. Although the Commission has previously found EIA's lowest gas case (High Supply) to be the most accurate, that has not been shown to be the case here. Accordingly, the ALJs find that ETI's Reference Gas case is reasonable.

c) Carbon Tax

The Commission has previously found that, while a future carbon tax is possible, it is not probable given past policy approaches to incentivizing carbon-free resources.[564] Here, ETI uses a range of carbon tax assumptions as part of its economic analyses.[565] TIEC argues that ETI unreasonably inflated its projected NPV of OCAPS by assuming a tax on carbon emissions in both its Reference and High Gas cases even though no legislation has ever been enacted that would impose a carbon tax.[566]

Mr. Griffey also opined that ETI unreasonably inflated its analysis by assigning a zero percent probability to the extension or augmentation of investment tax credits or production tax credits, despite strong industry and investor interest in doing so.[567] TIEC argues that the end result of ETI's

[564] Docket No. 51215, Final Order at 12 (FoF No. 98) (Oct. 19, 2021).

[565] ETI Ex. 25 (Nguyen Reb.) at 17-18.

[566] ETI Ex. 7 (Nguyen Dir.) at 17-18; Tr. at 173-74 (Nguyen Recross); TIEC Ex. 1 (Griffey Dir.) at 75.

[567] TIEC Ex. 1 (Griffey Dir.) at 74-77.

assumptions was to inflate the value of OCAPS relative to alternatives like solar and wind.

ETI argues that the United States and other nations have continued to place an emphasis on climate change and decarbonization.[568] Mr. Nguyen testified that it is prudent to consider a range of potential risk of exposure to carbon costs, in some form.[569] Accordingly, ETI developed a range of potential future outcomes spanning from zero carbon cost in the low case to a moderate carbon cost in the high case. Mr. Nguyen testified that the zero carbon cost assumption nevertheless showed OCAPS would yield significant benefits.[570]

The ALJ find that it was unreasonable for ETI to assume a carbon tax for the reasons set out by TIEC. This position is supported by the recently enacted IRA which does not include a carbon tax. However, it is unclear if this assumption results in unreasonably inflating the value of OCAPS because the ALJs find ETI's Reference Gas case, which includes carbon, reasonable.

d) Post-Hoc O&M Adjustment

Mr. Griffey testified that ETI unreasonably discounted the O&M costs for OCAPS relative to its generic 2x1 CCGT, thereby further inflating the benefits of OCAPS.[571] He testified that ETI's AURORA model assumed the

[568] ETI Ex. 25 (Nguyen Reb.) at 17-18; ETI Ex. 13 (Hebner Dir.) at 14-15.

[569] ETI Ex. 25 (Nguyen Reb.) at 17.

[570] ETI Ex. 25 (Nguyen Reb.) at 17.

[571] TIEC Ex. 1 (Griffey Dir.) at 78-81; TIEC Ex. 1A (Griffey Dir., Conf.) at 80-81.

same variable O&M cost for both the three CTs and for OCAPS, but ETI then lowered this cost for OCAPS "due to the separation of variable O&M from fixed O&M and capital costs included in the RFP proposal."[572] ETI then adds the difference between the O&M cost modeled in AURORA and its lowered O&M rate, multiplies that difference by the MWh output, and added the result to variable supply cost savings.[573]

In response, Mr. Nguyen explained that the AURORA models assumed the same variable O&M for the three CTs and OCAPS to eliminate any variable O&M bias, but this cost is then adjusted to account for the specific O&M rate for OCAPS.[574] He testified that this adjustment is appropriate to account for OCAPS-specific costs and is conservative to ensure no bias in the AURORA modeling.[575]

Although the ALJs accept that OCAPS-specific adjustments may be necessary to the AURORA model, Mr. Nguyen's testimony is conclusory and fails to justify the level of adjustment. Moreover, it is not clear that Mr. Nguyen's sensitivity analysis, which addressed only the fixed cost portion of the unit-specific costs, similarly controlled for these variable O&M costs. Therefore, the ALJs find that ETI failed to meet its burden of proof to show that discounting the O&M costs for OCAPS relative to its generic 2x1 CCGT was reasonable, thereby inflating the benefits of OCAPS.

[572] TIEC Ex. 1 (Griffey Dir.) at 78 (citing ETI response to TIEC RFI No. 4-1, 4-2, and 4-3).

[573] TIEC Ex. 1 (Griffey Dir.) at 78.

[574] ETI Ex. 25 (Nguyen Reb.) at 35-36.

[575] ETI Ex. 25 (Nguyen Reb.) at 36.

e) Capacity Value

TIEC argues that ETI inflated the capacity value of OCAPS by comparing OCAPS to three CTs, by assuming the capacity value for the three CTs was based on CONE, and inflating the avoided capacity price itself. TIEC argues that valuing the avoided capacity avoided at the CONE unreasonably inflates OCAPS' capacity value. Mr. Griffey testified that, because OCAPS has more capacity than the three CTs, ETI values the excess amount at its estimate of the CONE.[576] ETI's valuation of CONE is based on ETI's estimate of the levelized cost of a CT, which TIEC argues is overstated given the current CONE in MISO South.

TIEC argues that OCAPS' capacity value should not have been measured against three CTs and those three CTs' value should not have been valued at CONE. Instead, Mr. Griffey opined that the true alternative to OCAPS is not a long-term resource, but the projected MISO PRA prices, which constitutes the actual price of capacity in MISO.[577]

Next, TIEC argues that capacity should not be valued at CONE (currently $228.82/MW-Day).[578] Mr. Griffey testified that MISO LRZ 9 is oversupplied, driving down capacity prices. At the time Mr. Griffey filed his direct testimony, PRA prices for LRZ 9 were $2.88/MW-day and the highest ever recorded is $10/MW-day in planning year 2018-2019.[579] When supply equals demand in a load zone, PRA prices

[576] TIEC Ex. 1 (Griffey Dir.) at 81.

[577] TIEC Ex. 1 (Griffey Dir.) at 85-86; TIEC Ex. 1A (Griffey Dir., Conf.) at 52.

[578] TIEC Ex. 1 (Griffey Dir.) at 82, Fig. 20.

[579] TIEC Ex. 1 (Griffey Dir.) at 82.

are capped at MISO's estimate of CONE.[580] But capacity prices are historically unlikely to be set at MISO's CONE over time. PRA prices have only been at CONE for one year in LRZ 7 (Michigan), and in Load Resource Zones 1 through 7 in the most recent auction.[581] Looking to the future, the MISO South PRA, which has never been set to CONE, has a reserve margin near 45%, and load growth in MISO South is slow, making it unlikely that capacity prices will hit CONE during the initial part of OCAPS' life.[582] TIEC therefore argues that ETI should not have assumed that capacity should be valued at CONE when PRA prices are unlikely to rise to that level.

In the BP21, one of ETI's two possible forecasts projected that PRA prices would reach CONE immediately following OCAPS' activation,[583] which is unreasonable because it assumes on the one hand that only already-certified plants will be added, while also assuming that the units that planned resources are supposed to replace will be deactivated.[584] TIEC argues that only through that kind of unreliable analysis could ETI project that PRA prices might reach CONE.

Finally, TIEC argues that ETI's CONE is improperly inflated. Mr. Griffey testified that ETI assumed CONE to be $1,032 per kW instead of the MISO PRA's $673 per kW for the 2022 to 2023 PRA option.[585] TIEC cites to TIEC Exhibit 65 in

580 TIEC Ex. 1 (Griffey Dir.) at 81.

581 TIEC Ex. 1 (Griffey Dir.) at 83.

582 TIEC Ex. 1 (Griffey Dir.) at 35, 81-82, Fig. 20.

583 TIEC Ex. 1A (Griffey Dir., Conf.) at 83.

584 TIEC Ex. 1 (Griffey Dir.) at 83-84.

585 TIEC Ex. 1 (Griffey Dir.) at 57; Tr. at 521 (Griffey Redir.).

support of this position, which does not reflect the MISO PRA of $673 testified to by Mr. Griffey, but rather a MISO PRA of $676, which the ALJs assume was intended. Regardless, the ALJs assume TIEC argues that same planning year differential discussed above (i.e., the $956/kW 2026/2027 planning year price versus the $676/kW 2022/2023 planning year price), which the ALJs found reasonable as it accounts for cost escalations between now and 2026.

Mr. Griffey testified that if ETI had kept the avoided capacity price at zero until 2030 and then used the probabilistic method it used in Docket No. 51215, OCAPS' capacity benefit would be significantly reduced.[586]

ETI maintains that it appropriately assessed capacity value by comparing OCAPS to the three CTs. The three CTs represent the long-term resource cost that OCAPS will avoid. Mr. Owens testified that reliance on the PRA is not a reasonable long-term option.[587] MISO relies on LSEs to engage in long-term generation planning rather than the PRA to ensure resources adequacy.[588] MISO's resource adequacy construct recognizes that some LSEs will have a surplus and others will have a shortfall on a short-term basis.[589] The PRA creates a market whereby LSEs can sell excess to LSEs with a shortfall.[590] Mr. Griffey recognized that the PRA is a spot market and that most LSEs do not rely on it to meet their

[586] TIEC Ex. 1 (Griffey Dir.) at 88.

[587] ETI Ex. 12 (Owens Dir.) at 16-21.

[588] ETI Ex. 12 (Owens Dir.) at 12.

[589] ETI Ex. 12 (Owens Dir.) at 13.

[590] ETI Ex. 12 (Owens Dir.) at 12.

load requirements.[591] The PRA clearing price is capped at MISO's estimate of the levelized cost of a CT, i.e., CONE, but is not designed to attract new entry.[592] Therefore, an LSE that does not plan long-term for enough generation to meet its expected needs and instead relies on the PRA is in effect "leaning" on other LSEs to plan long-term resources in excess of their loads.[593] Consequently, ETI argues that Mr. Griffey's suggestion that ETI rely on the PRA as a means to reduce its long-term planning reserve requirement is at odds with MISO's resource adequacy construct.[594]

Thus, Mr. Owens testified that Mr. Griffey's proposal to use a projection of the PRA price for the purpose of valuing OCAPS is unreasonable because PRA purchases are not an alternative to OCAPS.[595] Mr. Owens further testified:

> ETI decided not to plan to rely on short-term purchases from the PRA. Instead, it reasonably and responsibly decided to plan enough capacity to meet its needs through ownership and/or long-term bilateral contract. Given that decision, it does not make sense to value the capacity benefits of OCAPS by comparison to a projection of the PRA price. Instead, it makes sense to value OCAPS by comparison to the cost of an alternative source of owned or long-term contracted capacity, which is what ETI did—five times.[596]

[591] Tr. at 489 (Griffey Cross).

[592] ETI Ex. 12 (Owens Dir.) at 6-8, 10, 13.

[593] ETI Ex. 12 (Owens Dir.) at 12-13.

[594] ETI Ex. 12 (Owens Dir.) at 17-21.

[595] ETI Ex. 12 (Owens Dir.) at 16-21.

[596] ETI Ex. 26 (Owens Reb.) at 16.

ETI also argues that relying on the PRA as a long-term planning strategy imposes significant risks as PRA clearing prices in MISO North/Central recently went from $5.00 to $236.66 in a single year because there was not sufficient capacity to cover reserves.[597] MISO is now warning those regions of heightened risk of controlled load shed events due to reserve deficiencies.[598] ETI further argues that Mr. Griffey's position is inconsistent with his admission that it would be reasonable for an LSE to secure incremental capacity prior to the point when the PRA reaches CONE.[599]

Regarding Mr. Griffey's suggestion that ETI value the capacity benefits of OCAPS using a projection of MISO's PRA price that is zero until 2030 and 56% of CONE thereafter,[600] Mr. Owens testified that this is an unreasonable projection of the PRA price to use for the purpose of valuing long-term capacity because it is so low that it would make many existing units in MISO candidates for immediate retirement and would also make it unattractive in most instances to build or contract for replacement capacity.[601]

The ALJs find that it was reasonable for ETI to value OCAPS' capacity by comparing its cost to an alternative long-term source of physical capacity, i.e., the levelized cost of new CTs.[602] The evidence conclusively shows that PRAs are not a

[597] ETI Ex. 44 at 15 (Bates 15)(MISO 2022-2023 Planning Resource Auction (April 2022)); Tr. at 490-92 (Griffey Cross).

[598] ETI Ex. 4 (Weaver Dir.) 4 at 2, 9; Tr. at 491 (Griffey Cross).

[599] Tr. at 492-93 (Griffey Cross).

[600] TIEC Ex. 1 (Griffey Dir.) at 17-18.

[601] ETI Ex. 26 (Owens Reb.) at 17-18.

[602] ETI Ex. 12 (Owens Dir.) at 20-21.

long-term planning solution. Mr. Griffey testified that "[t]he price volatility and risk inherent in relying on the spot price of capacity or gas need to be evaluated…."[603] The PRA are spot prices used to clear excess capacity which is subject to volatile availability and not designed to attract new entry, as is the CONE. Because the PRA is only a short-term solution to meet resource adequacy requirements, it is not an equivalent alternative to the capacity provided by a long-term resource in its early years or otherwise. Therefore, PRA prices are not an appropriate proxy for the value of OCAPS' capacity.[604] Accordingly, the ALJs find that ETI appropriately valued capacity at MISO's CONE, which is incidentally lower in Texas than elsewhere.[605]

6. Overall Analysis of Economic Evaluation

Based on the findings above, the ALJs conclude that the OCAPS acquisition, subject to the conditions discussed below (PFD Section XII), would result in a probable lowering of cost to ETI's customers. Although the ALJs agree with intervenors that a number of assumptions are unreasonable, they are not shown to eliminate the $1 billion of NPV in Mr. Nguyen's lowest benefit case (Table 4, above), which included no carbon tax assumption and controlled for many of the intervenors' concerns.[606] Moreover, this value is likely to increase somewhat with the elimination of the hydrogen component, as recommended.

[603] TIEC Ex. 1 (Griffey Dir.) at 85.

[604] ETI Ex. 12 (Owens Dir.) at 20-21.

[605] TIEC Ex. 65 at 9.

[606] ETI Ex. 25 (Nguyen Reb.) at 3.

C. Impact of OCAPS on Rates

Using Mr. Nguyen's initial cost estimate of $1.19 billion for OCAPS, ETI witness Allison Lofton, manager of regulatory filings, calculated the revenue requirement and bill impact. She estimated a first year base rate revenue requirement of $176.9 million, or $68.2 million after accounting for the $108.6 million in expected fuel savings, and a $9.84 per month increase in the average residential customer bill.[607] With the April cost estimate of $1.37 billion, the first year base rate revenue requirement rose to $200.9 million, or $92.2 million with the fuel savings offset, and a bill impact of $11.79 per month.[608]

The $108.6 million in fuel savings is based on Mr. Nguyen's calculated ETI Reference Gas case.[609] Cities note that if ETI's High Gas case turns out to be more accurate, which current conditions may support, the fuel savings could be as high as $204.7 million, which would drive down the first year revenue requirement.[610]

In support of the project, Mr. O'Donnell concluded that the initial projected cost to build the OCAPS facility is comparable to both the national average cost to build a similar plant as well as the cost to build the MCPS.[611] However, Cities concede that Mr. O'Donnell did not update his analysis after ETI filed its market escalation updates.

[607] ETI Ex. 11 (Lofton Dir.) at 4, 6.

[608] ETI Ex. 23 (Lofton Reb.) at 2-5, Table 2.

[609] ETI Ex. 11 (Lofton Dir.) at 5-6, Table 1; ETI Ex. 23 (Lofton. Reb.) at 3-4, Table 1; ETI Ex. 7 (Nguyen Dir.) at 25, Table 2.

[610] ETI Ex. 7 (Nguyen Dir.) at 25, Table 2.

[611] Cities Ex. 1 (O'Donnell Dir.) at 12–13.

Similarly, ETI did not provide an updated revenue requirement or bill impact estimate to reflect the June $1.58 billion OCAPS cost estimate or the $1.68 billion the Entergy Board approved for OCAPS.[612] Additionally, these estimates do not include the estimated $20 million cost of transmission upgrades, which will be the subject of a future certification proceeding.[613]

ETI commits to providing an updated estimate of the first-year revenue requirement and customer bill impact analysis when the new total project cost estimate, including a firm EPC price (per the EPC agreement), is obtained prior to the Commission's decision on this application.[614]

OPUC, Staff, and TIEC argue that ETI has failed to show a probable lowering of costs.

TIEC argues that even at the original cost estimate of $1.19 billion and its assessment of fuel cost savings, OCAPS would not provide net benefits to ratepayers in the foreseeable future. TIEC faults this estimate for (1) failing to include the cost of transmission upgrades or any sensitivity runs to reflect continued costs escalation, (2) holding the fuel cost savings the same despite the increasing capital cost, and (3) failing to show that the estimated fuel savings would offset the base rate increase.

[612] ETI Ex. 61 (ETI Board Minutes).

[613] ETI Ex. 23 (Lofton. Reb.) at 2.

[614] ETI Initial Brief at 65; Reply Brief at 41.

TIEC argues that even assuming no further escalation beyond the $1.68 billion approved by the Entergy Board in June, the net cost to ratepayers in the first year alone would be $140 million, applying ETI's own projection of fuel savings, (i.e., $249 million base rate increase minus $109 million in projected fuel cost savings).

TIEC further faults Ms. Lofton's calculation for relying on Mr. Nguyen's economic analysis, which TIEC finds unrealistic.[615] Assuming a cost of $1.61 billion for OCAPS, Mr. Griffey estimated the net rate impact during the first six years of operation to be over $600 million, which in his opinion would correct some, but not all, of ETI's errors.[616]

ETI admits that the factors that have driven the cost estimates up so dramatically will continue to affect the final cost, both through further escalations in the EPC cost until ETI issues a notice to proceed, and further escalations to EPC and non-EPC costs alike following the issuance of the notice to proceed.[617] Mr. Viamontes testified that without a price cap, ETI would be free to enter into a $2.5 billion contract with the EPC contractor without any further approval from the Commission, if that is what the costs have escalated to.[618] Even after issuing the notice to proceed, the EPC costs can escalate

[615] ETI Ex. 11 (Lofton Dir.) at 5.

[616] TIEC Ex. 1 (Griffey Dir.) at 91-93 (declassified). Mr. Griffey presciently estimated the cost of OCAPS at $1.61 billion in March 2022. *See also* OPUC Ex. 1 (Nalepa Dir.) at 22 (similarly estimating the cost to be closer to $1.57 billion).

[617] Tr. at 19 (Viamontes Cross).

[618] Tr. at 30 (Viamontes Cross).

due to change orders or force majeure events, which are broadly defined to include, among other things, wars, pandemics, and "any other causes, contingencies, or circumstances not subject to the reasonable control of and not caused by negligent acts or omissions of the Party seeking relief and which prevent or hinder performance."[619] And non-EPC costs will not be known until they are incurred.[620]

TIEC argues that ETI cannot meet its burden to demonstrate the probable lowering of costs to consumers. Staff argues that because of these cost increases the project should only be approved with conditions on the costs recoverable through rates.

D. Analysis

Although placing OCAPS into rate base will have a significant impact on rates, it was reasonably shown to have benefits over the life of the project at a cost of $1.37 billion.[621] There is no evidence that the project will confer similar savings at the known $1.58 billion cost estimate or continuing price escalations. The ALJs agree with TIEC that the EPC contract gives no assurances that unanticipated events will not further increase the costs, and ETI shows no sign of shying away from even a $2.5 billion cost. ETI's commitment to update the parties and the Commission before it considers this case, and the potential for further near certain increases after certification to be checked only by prudence review, is small comfort to those taking the risk. As noted above, the ALJs find that the OCAPS project

[619] ETI Ex. 8A (Ruiz Dir., Conf.), Exh. CR-8 (Bates 91 of 2120) (Section 33.2), (Bates 92 of 2120) (Article 5.4), (Bates 95 of 2120) (Section 37.7); Tr. at 197 (Ruiz Cross).

[620] Tr. at 40 (Viamontes Cross).

[621] ETI Ex. 25 (Nguyen Dir.) at 3, Table 2.

would result in a probable lowering of cost to ETI's customers based only on ETI's rebuttal testimony; without a cap, there is significant risk it would result in negative net benefits.

X. IMPACT ON IMPLEMENTATION OF CUSTOMER CHOICE (P.O. ISSUE NO. 24)

Pursuant to PURA section 39.452, the Commission must consider what effect approval of the CCN would have on the implementation of customer choice in ETI's service territory. The Commission also requested analysis of how ETI would mitigate market power and achieve full customer choice, including alternatives for constructing additional transmission facilities, auctioning rights to generation capacity, divesting generation capacity, or any other measure that is consistent with the public interest.

A. Party Positions

ETI maintains that the addition of OCAPS will not impact the implementation of customer choice. As an initial matter, ETI stresses that there is no plan for, or discussion of, the initiation of steps to transition to customer choice. If, however, the Commission decides to implement customer choice in ETI's service territory, ETI contends that the Commission will still have the authority to do so as contemplated by PURA section 39.452. This statute also gives the Commission the authority to mitigate market power and address any stranded costs, if necessary. However, even if started immediately, ETI maintains that the process would extend well past the in-service date for OCAPS.

ETI further argues that market power is not an issue here. With OCAPS, ETI is replacing capacity that will deactivate, not adding incremental capacity. As such, ETI contends that OCAPS will not change ETI's relative position regarding market power. ETI's perspective is that the proper approach to consider market power would be to compare ETI's position relative to MISO as a whole, rather than to focus on MISO South. Finally, ETI argues that nothing in PURA § 39.152(b) or the approval of OCAPS limits the Commission's authority to address market power.

Regarding stranded costs, ETI argues that any speculation regarding an over-supplied MISO market, which, in turn, could result in stranded costs should ETI ever implement customer choice, is outweighed by the construction of 1,215 MW dispatchable power that is needed to maintain regional reliability.

TIEC argues that OCAPS could impede the transition to competition in two ways: (1) climbing estimated costs to build OCAPS are increasingly likely to create stranded cost exposure, and (2) increased market power. TIEC is concerned that the increasing build-out of renewable resources could result in an over-supplied MISO market that would make a high-capital-cost plant uneconomic. Stranded costs issues, Mr. Griffey opined, were some of the most difficult issues in the transition to competition in ERCOT, which ratepayers ended up paying.

TIEC also contends that the increased market power in MISO South, where ETI's market share of excess capacity is projected to be 41% even without OCAPS, would be an impediment to retail competition. Essentially, TIEC maintains that allowing the dominant player in the market to add a 1,200 MW high-capital-cost plant to its portfolio could make the transition substantially harder.

B. Analysis

The ALJs conclude that although OCAPS may have an effect on the implementation of customer choice in ETI's service territory, a meaningful evaluation of the exact effect is tenuous at this point. No initiation of customer choice has occurred. And, although it is foreseeable that some increase in ETI's market share may occur (despite deactivation plans), the ALJs further conclude that the addition of necessary dispatchable power and related regional reliability outweigh any potential effects on customer choice.

XI. UNCONTESTED ISSUES

ETI witness Deborah Saxton's testimony on the following issues is uncontested, and, therefore, the ALJs make findings consistent with the testimony.

A. Regulatory Approvals (P.O. Issue Nos. 8-13)

ETI must seek regulatory approvals from multiple regulatory authorities to construct OCAPS. ETI included a table listing these regulatory authorities within its EA.[622]

[622] ETI Ex. 9 (Saxton Dir.), Att. DS-1, Table 5-1 at 69 (Bates 95).

B. Community, Historical and Aesthetic Values, Recreational and Park Areas (P.O. Issue No. 25 a-c)

The EA assessed the effects of the construction of OCAPS on community values, recreational and park areas, and historical and aesthetic values. No party challenged the findings of the EA.

1. Community Values

The nearest city, Bridge City, has its city hall and utilities office located approximately 1.5 miles east of the project site, with the nearest residences in Bridge City located approximately 0.5 miles east of the project boundary. The nearest Bridge City residences and sensitive receptors will be separated from the project site by a buffer of undeveloped forest and marshland. The residential area along the northern and northeastern boundary of the project site does not appear to be included within the city limits of Bridge City or the extra-territorial jurisdiction of any municipality.[623]

2. Residential Areas

OCAPS will not significantly affect any nearby residential areas. The residential subdivisions that exist along the northern and northeastern boundary of the project site were put in place after the Sabine Power Station was placed in service. While there will be temporary increases in noise at the project site during construction, ETI does not expect that OCAPS will significantly alter the current visual landscape or noise levels during its operation. ETI will manage the

[623] ETI Ex. 9 (Saxton Dir.) at 17.

construction of OCAPS in a manner that implements appropriate noise control measures that comply with local noise ordinances.[624]

3. Recreational and Park Areas and Historical and Aesthetic Values

There will not be a major shift in land use in the area since the project site has been used for the Sabine Power Station for over 50 years. There will be a shift in secondary land-use due to the conversion of undeveloped industrial land to developed industrial land.[625]

There are no parks or recreational areas in the immediate vicinity of the project site. There are no commercial or institutional uses in the immediate area that could be disrupted. The project will not be located within one mile of any park areas or cultural and historical resources. The location of OCAPS at an existing site will cause minimal effect on aesthetics in the area.[626]

C. Costal Management Program

OCAPS is both consistent with the goals and applicable policies of the Coastal Management Program (CMP) in accordance with 16 Texas Administrative Code section 25.102(a). OCAPS will not have any direct and significant impact on the applicable coastal natural resource areas.[627]

[624] ETI Ex. 9 (Saxton Dir.) at 16.

[625] ETI Ex. 9 (Saxton Dir.) at 15.

[626] ETI Ex. 9 (Saxton Dir.) at 15.

[627] ETI Ex. 17 (Saxton Supp. Dir.) at 9.

As with the existing Sabine units, OCAPS will be sited within the mapped CMP boundary as defined in 31 Texas Administrative Code section 503.1(a) and seaward of the coastal facility designation line as defined in 31 Texas Administrative Code section 19.2(A)(21).[628] The Commission's rule regarding the CMP provides that the Commission may grant a certificate for the construction of generating or transmission facilities within the coastal boundary when it finds that the proposed facilities are consistent with the applicable goals and policies of the CMP, or that the proposed facilities will not have any direct and significant impacts on any of the applicable coastal natural resource areas.[629]

The location of OCAPS at a site that was previously disturbed for industrial use for over 50 years complies with the policy that "new electric generating facilities shall, where practicable, be located at previously developed sites" and the requirement that electric generating facilities should be constructed to have the least adverse effects practicable on recreational uses of coastal natural resource areas used for spawning, nesting, and seasonal migrations of terrestrial and aquatic fish and wildlife species.[630] Finally, OCAPS will not use once-through cooling; therefore, 31 Texas Administrative Code section 501.16(a)(2) is not applicable.[631]

[628] ETI Ex. 17 (Saxton Supp. Dir.) at 6.

[629] 16 TAC § 25.102(a). 31 TAC § 501.14(a) was repealed and replaced by 31 TAC § 501.16. 29 Tex. Reg. 7038 (Jul. 23, 2004) and 29 Tex. Reg. 9409 (Oct. 1, 2004).

[630] ETI Ex. 17 (Saxton Supp. Dir.) at 9.

[631] 31 TAC § 501.16(a)(2).

D. Texas Parks and Wildlife Department (P.O. Issue No. 36)

Under Texas Parks and Wildlife Code (TPWC) sections 12.0011(b)(2) and (b)(3), TPWD has authority to provide recommendations that will protect fish and wildlife resources to local, state, and federal agencies that approve, license, or construct developmental projects. Under TPWC section 12.0011(c), the Commission shall respond in writing to the recommendations filed by the TPWD. On November 9, 2021, TPWD filed a letter making several recommendations. In response, Ms. Saxton filed supplemental testimony addressing TPWD's recommendations.[632] Staff witness Ms. Ghanem reviewed the EA submitted in the application as well as TPWD's recommendations and identified several mitigation measures that she found sufficient to address most of TPWD's concerns.[633] Staff therefore recommends that ETI be ordered to implement the measures described in the supplemental testimony of Ms. Saxton if the application is approved.

E. Seven-Year CCN Limitation (P.O. Issue No. 49)

Staff concluded that ETI has not described any special circumstances that would support modifying the seven-year deadline for ETI to commercially energize the transmission line.

[632] ETI Ex. 17 (Saxton Supp. Dir.) at 4, Exh. DS-SD-1.

[633] Staff Ex. 1 (Ghanem Dir.) at 21-22.

XII. POTENTIAL CONDITIONS IF THE COMMISSION APPROVES THE APPLICATION AND OTHER ISSUES (P.O. ISSUE NOS. 7, 48)

Staff, OPUC, and Cities argue that if the Commission approves the application, certain conditions should be placed on the OCAPS project. ETI argues that no conditions are appropriate.

A. Cost Cap

Staff recommends imposing a cost cap for the project. Given the increasing costs, Ms. Ghanem recommended that the Commission cap the cost recoverable through rates to an updated reasonable estimate.[634] Staff recommends that the cost cap be set at the current cost estimate, excluding the hydrogen component for the construction, but including AFUDC. For authority, Staff references the SWEPCO Turk plant, where the Commission capped the recovery of the cost of a generation project to protect ratepayers from the financial risk arising out of uncertainties in the project, and, therefore, setting a cost limitation is warranted given the circumstances of the case.[635]

ETI argues that a cost cap is inappropriate because it would exclude the investment necessary to unlock the benefits of OCAPS' dual fuel capability and would ignore the market escalation impacting the project. ETI further argues that it is entitled to the opportunity to earn a return of and on the invested capital used to serve its customers and, as such, a cost cap is inconsistent with resources in which

[634] Staff Ex. 1 (Ghanem Dir.) at 23.

[635] Docket No. 33891, Final Order at 20 (OP No. 2) (Aug. 12, 2008).

ETI invests to address a capacity need because those resources are necessary to serve the public. ETI further argues that a cap has the potential to disallow prudent costs, and, ETI maintains, a CCN proceeding is not the forum to determine the prudence of specific costs incurred. Finally, ETI posits that, if the Commission does decide to impose a cost cap, it should be in excess of the current forecasted cost of the project.[636]

PURA section 37.056 authorizes the Commission to grant or deny a certificate. It also authorizes the Commission to "grant the certificate for the construction of a portion of the requested system, facility, or extension or the partial exercise of the requested right or privilege."[637] As such, ALJs conclude that the Commission has authority to place a limit on its approval of recoverable costs in a CCN proceeding.

The ALJs are persuaded that certain conditions should be placed on the cost recovery for this project. As noted above, the ALJs found a probable lowering of cost to customers based on evidence in the record. This evidence shows a positive NPV at the $1.37 billion cost estimate presented in ETI's rebuttal testimony.[638] Although Mr. Nguyen testified that this showed benefits even at a $1.61 billion cost estimate, that number does not appear to have been used in his workpapers.[639] Therefore, evidence of a positive NPV at any amount beyond $1.37 billion is not in

[636] ETI Ex. 29 (Weaver Reb.) at 5.

[637] PURA § 37.056(b)(2).

[638] ETI Ex. 25 (Nguyen Reb.) at 3.

[639] ETI Ex. 25B (Nguyen Reb., WP) at Bates 13 of 29 (HSPM).

the record; accordingly, the ALJs find that Staff's recommended cap at the June estimate ($1.58 billion) is not appropriate.

Cities observe that cost escalation is not biased toward OCAPS[640] but applies equally to any alternative investment ETI could make to address its capacity need. However, there are many moving parts, of which all are not equally affected by the cost drivers. As TIEC points out, unlike inflation which does apply equally, OCAPS-specific cost increases may not have affected other resources, like solar panels, wind turbines, and batteries.[641] This potentiality may be enhanced by the IRA.[642] ETI's 2019 Portfolio Analysis reasonably assessed a range of technologies, including solar and batteries, and rejected those options based in part on the economics at the time. As Mr. Nalepa observed, the cost by which Portfolio 2 beat out those alternatives was extremely small.[643] Therefore, the ALJs find that a simple linear extrapolation of increased costs to decreased benefits, as ETI proposes (a 1:0.5 cost/benefit ratio), fails to account for the impact on the alternatives left behind and is entirely speculative. At some point, those alternatives may need to be revisited.

Although the ALJs agree that ETI is entitled to the opportunity to earn a return of and on the invested capital used to serve its customers, that opportunity must have a limit. Where, as here, substantial uncertainty surrounding the project exists, ratepayers must be protected from significant financial risk. Accordingly, the

[640] Cities Initial Brief at 12.

[641] TIEC Reply Brief at 33-34.

[642] *See* Inflation Reduction Act of 2022, §§ 13101, 13102, 13701, 13702.

[643] OPUC Ex. 1 (Nalepa Dir.) at 12, Table 2.

ALJs recommend that cost recovery be capped at the $1.37 billion cost estimate presented in ETI's rebuttal testimony,[644] the most recently updated record evidence that the project will confer a benefit and is the best option relative to alternatives.

B. Exclusion of Hydrogen

Staff and OPUC recommend excluding the hydrogen portion of the plant and all associated costs. In addition to the arguments made previously (see PFD Section VIII, above), OPUC argues that the ability to co-fire hydrogen was not considered in ETI's portfolio analysis or in its RFP process and, as such, the hydrogen portion of the project was never modeled, submitted for a competitive bid, or shown to be an economic or necessary component of OCAPS.[645]

As discussed above, the ALJs are persuaded by the arguments and recommend that the Commission exclude the hydrogen portion of OCAPS and any associated costs.

C. Transmission and Interconnection Costs

OPUC contends that the $85.9 million future transmission upgrade costs and interconnection of OCAPS to ETI's system should be excluded because these costs will be subject to a separate certification proceeding.[646] More specifically, OPUC recommends removing the costs of the future transmission upgrades and

[644] ETI Ex. 27 (Ruiz Reb.) at 3; ETI Ex. 25 (Nguyen Reb.) at 3.

[645] OPUC Ex. 1 (Nalepa Dir.) at 14.

[646] ETI Ex. 8 (Ruiz Dir.) at 15.

limiting recovery to the $15.4 million needed costs to interconnect OCAPS to ETI's system. The ALJs decline this recommendation because these costs will be subject to a separate certification proceeding.

D. Weatherization

Staff recommends that ETI be ordered to commit resources for proper weatherization of OCAPS to withstand conditions at least as severe as Winter Storm Uri. This issue is addressed above in the reliability discussion (see PFD Section IX.A).

E. Heat Rate Guarantee

Cities argue that, because the projected fuel savings is based on OCAPS achieving a heat rate of about 6,200 BTU/kWh (or 40% better than existing ETI heat rates), the heat rate guarantee in the EPC agreement should be memorialized in the Commission's final order, which ETI does not oppose.[647] The ALJs recommend this guarantee be adopted in the Commission's final order.

XIII. OVERALL RECOMMENDATION

Regarding the PURA section 37.056(c) factors, ETI's service is adequate, but it has short-term and long-term needs for capacity, which OCAPS would meet with its nominal output of 1,215 MW of generating capacity. OCAPS would result in probable improvement of service, including reliability of service. OCAPS would not confer any appreciable reliability benefits resulting from a dual fuel capability.

[647] ETI Ex. 27 (Ruiz Reb.) at 6.

OCAPS will have a positive impact on electric utilities serving the proximate area. It would not adversely affect recreational and park areas, historical values, or environmental integrity. It would have minimal effect on aesthetic values. It would not contribute toward meeting the state's renewable energy goal, set out in PURA section 39.904(a), because that goal has already been met.

OCAPS will have a probable lowering of cost to consumers at a cost of no more than $1.37 billion. As noted at the outset, the CCN factors reflect potentially competing policies and interests whose relative weight will vary with the particular circumstances of each case.[648] ETI has shown a clear need for the resource, in capacity, energy and reliability, consistent with prudent planning, and that the resource would improve service in the area. No party disputes the need to replace the 500 MW ETI will lose with the retirement of Sabine 1 and 3. ETI has also demonstrated that it would be prudent to retire Sabine 4, resulting in an additional 500 MW need. The question is whether OCAPS is the plant for the job. No party has suggested a viable alternative that does not include extending the life of Sabine 4 or reliance on transmission. ETI has shown that neither of those options would meet its particularized need. In this case, the ALJs find that the need and improvement in service should be given great weight.

[648] *See Public Util. Comm'n of Tex. v. Texland Elec. Co.*, 701 S.W.2d 261, 266-67 (Tex. App.—Austin 1985, writ ref'd n.r.e.) ("To implement in particular circumstances such broadly stated legislative objectives and standards, the Commission must necessarily decide what they mean in those circumstances; and because some of them obviously compete *inter se*, the agency may in some cases be required to adjust or accommodate the competing policies and interests involved. For example, a 'need' for additional service implies a relative requirement, ranging from imperative need to one that is minimal; and, if a 'need' be sufficiently grave, it may have to prevail notwithstanding an adverse [e]ffect upon another interest, such as the environment," and *vice versa*).

Having weighed the evidence, the ALJs conclude that ETI has met its burden of proof to show that the certificate is necessary for the service, accommodation, convenience, or safety of the public. Accordingly, the ALJs recommend the Commission certify OCAPS, subject to the conditions set out above.

XIV. FINDINGS OF FACT, CONCLUSIONS OF LAW, AND PROPOSED ORDERING PARAGRAPHS

A. FINDINGS OF FACT

The Applicant

1. Entergy Texas, Inc. (ETI) provides fully bundled electric delivery service to approximately 486,000 customers across 27 counties in Southeast Texas.

2. ETI is authorized under Certificate of Convenience and Necessity (CCN) number 30076 to provide service to the public and to provide retail electric utility service within its certificated service area.

The Application

3. On September 16, 2021, ETI filed an application requesting an amendment to its CCN to construct, own, and operate the Orange County Advanced Power Station (OCAPS or the Project), a new combined-cycle combustion turbine (CCCT) facility to be located in Bridge City, Texas.

4. ETI's application included the direct testimony of 12 witnesses.

Notice of the Application and Procedural History

5. On September 16, 2021, ETI provided notice of the application to (a) all the parties to ETI's most recent base rate case; (b) the county judge in Orange County; and (c) the governing bodies of the cities of Bridge City, Orange,

Port Neches, Nederland, Groves, and Port Arthur (the only municipalities within five miles of the OCAPS site).

6. On September 16, 2021, ETI provided notice of the application to the Department of Defense Clearinghouse.

7. Between the dates of September 21, 2021, to September 29, 2021, ETI published notice of the application in the following newspapers of general circulations in ETI's retail service territory: *Anahuac Progress, Beaumont Enterprise, Brenham Banner, Bryan/College Station Eagle, Burleson County Citizen Tribune, Cameron Herald, Conroe Courier, East Montgomery County Observer, Franklin Advocate, Galveston County Daily News, Grapeland Messenger, Groesbeck Journal, Hometown Press, Houston Chronicle, Houston County Courier, Humble Observer, Huntsville Item, Jasper Newsboy, Kirbyville Banner, Liberty Vindicator, Madisonville Meteor, Marlin Democrat, Montgomery County News, Navasota Examiner, Newton County News, Normangee Star, Orange Leader, Penny Record/County Record, Polk County Enterprise, Port Arthur News, Robertson County News, San Jacinto News Times, Silsbee Bee, Trinity County News Standard, Tyler County Booster, Waller County Times,* and *The Woodlands Villager.*

8. In Order No. 1 issued on September 17, 2021, the Administrative Law Judge (ALJ) for the Public Utility Commission of Texas (Commission) ordered Commission staff (Staff) to respond to ETI's application by providing comments on the sufficiency of the application and proposing notice and to propose a procedural schedule. The Commission ALJ also adopted the standard protective order.

9. On October 6, 2021, ETI filed affidavits attesting to proof of notice by mail and proof of publication.

10. On October 8, 2021, the Commission ALJ granted the motions to intervene of the Office of Public Utility Counsel (OPUC); Texas Industrial Energy Consumers (TIEC); East Texas Electric Cooperative, Inc. (ETEC); and the Cities of Anahuac, Beaumont, Bridge City, Cleveland, Dayton, Groves, Houston, Huntsville, Liberty, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Pinehurst, Port Arthur, Port Neches,

Roman Forest, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, West Orange, and Willis (collectively, Cities).

11. On October 15, 2021, Staff recommended that the notice and application be found sufficient and proposed a procedural schedule.

12. On October 18, 2021, the Commission ALJ issued Order No. 3 finding ETI's application administratively complete and the notice sufficient, and establishing a procedural schedule.

13. On October 26, 2021, Staff requested a hearing and a referral to the State Office of Administrative Hearings (SOAH).

14. On November 9, 2021, the Commission ALJ issued Order No. 4, granting the interventions of Sierra Club and International Brotherhood of Electrical Workers, Local 2286 (IBEW 2286).

15. On November 9, 2021, Commission Counsel issued an Order Requesting Lists of Issues.

16. On November 15, 2021, ETI filed its List of Issues to be addressed in the proceeding.

17. On November 19, 2021, Sierra Club, Staff, and TIEC filed Proposed Lists of Issues to be addressed in the proceeding.

18. On December 8, 2021, ETI filed the direct testimony of Eliecer Viamontes, who adopted and sponsored the pre-filed direct testimony and exhibit of Sallie T. Rainer.

19. On December 13, 2021, the Commission referred this proceeding to SOAH.

20. On December 15, 2021, the SOAH ALJs issued SOAH Order No. 1 setting the prehearing conference, confirming the applicable statutory deadline of September 19, 2022, pursuant to Public Utility Regulatory Act (PURA) § 37.058(d), and establishing filing deadlines and procedures.

21. On December 16, 2021, the Commission issued a Preliminary Order listing the issues to be addressed in this proceeding.

22. On January 14, 2022, ETI filed supplemental direct testimony of four witnesses to address issues that were raised in the Preliminary Order.

23. On February 2, 2022, the SOAH ALJs issued SOAH Order No. 2 setting the contested case procedural schedule and scheduling the hearing on the merits.

24. On March 18, 2022, Sierra Club, Cities, OPUC, and TIEC filed direct testimony, and IBEW Local 2286 filed a statement of position.

25. On March 28, 2022, Staff filed direct testimony.

26. On March 29, 2022, the SOAH ALJs issued SOAH Order No. 6 providing instructions and deadlines relating to the prehearing conference, the hearing, and briefs.

27. On April 12, 2022, ETI filed rebuttal testimony.

28. On April 22, 2022, ETEC filed a statement of position.

29. On April 26, 2022, ETI filed a motion to modify the procedural schedule which included continuing the hearing on the merits to June 29-July 1, 2022.

30. On April 26, 2022, the SOAH ALJs issued SOAH Order No. 8 granting ETI's motion.

31. On May 4, 2022, the SOAH ALJs issued SOAH Order No. 9 setting the hearing on the merits and prehearing procedures.

32. On May 11, 2022, TIEC filed supplemental direct testimony.

33. On May 20, 2022, ETI filed supplemental rebuttal testimony.

34. On May 24, 2022, TIEC filed a statement of position.

35. On June 27, 2022, Sierra Club filed a statement of position.

36. The hearing on the merits was held via videoconference on June 29 - July 1, 2022.

37. On July 8, 2022, the SOAH ALJs issued SOAH Order No. 10 setting the post-hearing briefing schedule and guidelines.

38. On July 18, 2022, Staff, ETI, OPUC, Cities, Sierra Club, and TIEC filed initial post-hearing briefs.

39. On July 29, 2022, Staff, ETI, OPUC, Cities, Sierra Club, and TIEC filed reply briefs.

40. On July 29, 2022, ETI filed proposed findings of fact, conclusions of law, and ordering paragraphs.

41. On August 24, 2022, TIEC filed a request for supplemental briefing on the recently passed Inflation Reduction Act.

42. On August 25, 2022, the SOAH ALJs issued SOAH Order No. 11 addressing the proposed additional briefing.

43. On August 31 and September 1, 2022, ETI, TIEC, Cities, ETEC and Sierra Club filed responses to SOAH Order No. 11.

44. On September 1, 2022, the SOAH ALJs denied the request for supplemental briefing.

45. The record closed on July 29, 2022, with the filing of reply briefs.

<u>Description of the Plant to be Included in ETI's CCN</u>

46. OCAPS will provide a nominal output of 1,215 megawatts (MW) and a summer output of 1,158 MW of clean, dispatchable capacity in the industrial corridor of Southeast Texas to help ensure ETI is able to supply power to Texas customers in a reliable and economic manner for decades to come.

47. OCAPS is based on modern, commercially proven combustion turbine technology with dual fuel capability, able to co-fire up to 30% hydrogen by volume upon commercial operation and upgradable to support 100% hydrogen operations in the future, as market conditions dictate.

48. At the time of filing the application, the estimated cost for OCAPS was approximately $1.19 billion inclusive of $1.107 billion of generation project costs and $85.9 million in transmission upgrade costs.

49. Due to cost escalation in the global economy, in June 2022, ETI provided an updated cost estimate for OCAPS of $1.58 billion, contingent upon issuance of limited notice to proceed by July 15, 2022.

50. OCAPS will be located at ETI's Sabine Power Station site in Bridge City.

51. OCAPS will be constructed to use ETI's Spindletop gas storage facility.

52. ETI will construct, own, and operate OCAPS.

53. ETI expects that OCAPS will achieve commercial operation in 2026.

Regulatory Approvals and Notice

54. ETI's Application is sufficient for consideration.

55. ETI's notice in this proceeding is sufficient.

56. The authority granted by this Order will be limited to a period of seven years from the date the Order is signed, unless OCAPS is commercially operational before that time.

Consideration of Statutory CCN Factors

Adequacy of Existing Service and Need for Additional Service

Adequacy of Existing Service

57. ETI currently provides adequate service to its customers.

Need for Additional Service

58. ETI has a need for the additional capacity and energy.

59. By 2026, ETI plans to deactivate from service three legacy gas-fired steam generating units, Sabine 1, 3, and 4, due to age and reliability concerns.

60. ETI's decision to retire Sabine 4 in 2026 is based on reasoned judgment informed by the unit's age and, increasingly over time, its condition, criticality, reliability, and economics.

61. Significant age-related conditions (including gas supply valve wear, water pump replacement and failures, stop-valve replacement, hot spots on the boiler, frequent tube leaks in multiple key components, and air duct failures) have begun increasing Sabine 4's forced outage rate and degradation to its max capacity.

62. Sabine 4's outage rate over the past five years has increased 50% as compared to the previous five-year period.

63. Sabine 4's unforced capacity used by MISO to determine capacity credit has recently decreased, and its Generator Verification Test Capacity has degraded approximately 30 MW over the past five years.

64. The average Equivalent Forced Outage Rate Demand for Sabine 4 over the last five years is approximately 25% and has been as high as 35% during that time.

65. Sabine 4 was only available for approximately 30 days during the first six months of 2022, and at less than its full capacity during all of those days.

66. From an environmental compliance standpoint, Sabine 4 has been derated or taken offline several times to comply with nitrogen oxide (NOx) emission limitations.

67. A proposed new United States Environmental Protection Agency rule would establish NOx emission allowance budgets for gas-fired power plants and could require ETI to spend approximately $60 million to install Selective Catalytic Reduction controls at Sabine 4 by 2026 to continue operations, which is incremental to the estimated capital upgrades modeled in ETI's 2019 Portfolio Analysis.

68. There is a real risk that further investment in Sabine 4 may not maintain or improve its forced outage rate.

69. There is a substantial risk that unknown conditions could lead to the failure of Sabine 4 from which the unit could not return to service, regardless of any further investment in the unit.

70. Sabine 4 should be retired and deactivated in 2026 as ETI proposed.

71. The orderly deactivation of Sabine 1 in 2023 and Sabine 3 and 4 in 2026 is necessary to ensure reliable service to ETI's customers.

72. ETI's coincident peak load is expected to grow approximately 10.3% (or 348 MW) by 2026, primarily due to large industrial load additions.

73. Any reasonably expected variation from ETI's load forecast will not result in ETI being substantially long on energy or capacity for any extended period of time based on the addition of OCAPS.

74. ETI's load has grown at a level comparable to its 2021 Business Plan forecast.

75. ETI's sales and load forecasting methodology and processes are reasonable and appropriate.

76. ETI's long-term planning reserve margin of 12.69% appropriately and reasonably reflects the amount of capacity that must be planned, during the approximate four years required to plan, develop and construct new capacity, to ensure that firm load would be curtailed only once every 10 years.

77. Based on the deactivation of Sabine 1, 3 and 4 and its project load growth, and accounting for its long-term planning reserve margin, ETI will have a capacity shortfall of approximately 1,073 MW in 2026 that OCAPS will help to meet.

78. Changes to ETI's supply plan in its 2022 Business Plan reflecting new solar additions in 2025 and beyond do not displace the need for OCAPS to address the capacity shortage in 2026.

79. ETI has a projected energy deficit of 9.2 terawatt-hours by 2026, representing approximately 40% of the energy needed to serve ETI customers.

80. ETI's 2019 Portfolio Analysis addressed its 2026 capacity and energy needs and evaluated the performance of five reasonable resource portfolio alternatives across four potential future scenarios encompassing a range of market outcomes, considering ETI's overall capacity, energy, and reliability needs, among other factors.

81. Portfolio 2, consisting of a 2x1 CCCT located at the Sabine site, had the lowest total supply costs and most closely aligned generation and demand over the study period, reducing customers' exposure to energy market price risk.

82. Portfolio 2 was more economic than every other portfolio analyzed across every future evaluated by a range of $56 million to $320 million net present value (NPV).

83. Portfolio 2 was comparable to Portfolios 1, 3, and 4 from a risk standpoint.

84. Portfolio 5, which consisted of a 1x1 CCCT and extending the service life of Sabine 4 to 2034, was riskier than all other portfolios from a reliability standpoint.

85. Extending Sabine 4 to 2034 would not allow full transfer of the transmission rights at the Sabine site, and would require ETI to seek incremental transmission service from the Midcontinent Independent System Operator, Inc. (MISO) and pay significant costs associated with transmission upgrades in 2034.

86. ETI cannot reasonably ensure reliable service with an assumed 2034 deactivation date for Sabine 4, given the age and condition of the unit, even with significant and continued capital investments.

87. Portfolio 5's extension of Sabine 4 to 2034 carries unreasonable reliability and economic risk for ETI's customers.

88. Portfolio 2 is the best option for addressing the long-term capacity, energy, and reliability needs of ETI's customers.

89. ETI initiated the 2020 Request for Proposal (RFP) to solicit competitive proposals for between 1,000 MW and 1,200 MW of capacity supplied from CCCT technology located in the Eastern Region of ETI's service area.

90. The RFP resulted in the selection of OCAPS, which has significant projected economic and reliability benefits to ETI's customers.

91. ETI appropriately designed the 2020 RFP to secure the resource previously determined to best address the resource needs of ETI customers.

92. The RFP process was undertaken in a fair, unbiased, and equitable manner.

93. Building additional transmission to import power into ETI's service territory is not a practical or cost-effective option to address ETI's capacity and energy needs.

94. To materially impact the import capability into the load pocket in which ETI's service territory sits, an investment of over $1 billion would be required.

95. A $1 billion transmission investment will not address the need for sufficient long-term generation to meet ETI's capacity and energy needs or provide the reactive power support critical to serving the significant industrial load in ETI's Eastern Region.

96. It was reasonable for the RFP to solicit resources in ETI's Eastern Region.

97. The RFP included a provision that gave ETI the unilateral right to terminate a PPA if the PPA became a liability on ETI's books, such as if it were deemed a lease.

98. The RFP included a provision that shifted the risk of regulatory disallowances to a successful PPA bidder.

99. The RFP terms were reasonable.

Hydrogen Co-Firing Capability

100. ETI's 2019 Portfolio Analysis did not include a hydrogen-enabled combined cycle gas turbine like OCAPS.

101. In February 2022, ETI estimated the cost of the hydrogen component proposed for OCAPS at $91 million.

102. ETI did not conduct any economic or cost-benefit analysis of OCAPS' hydrogen component.

103. ETI did not produce any forecasts for the price of hydrogen on a dollar per thousand cubic feet or million British thermal unit (MMBtu) basis.

104. ETI did not analyze the dual fuel benefit of hydrogen relative to gas storage at Spindletop or to liquid fuel back-up at OCAPS.

105. ETI did not meet its burden to prove the improvement of service or lowering of cost to consumers in the area is probable if the certificate is granted, when including any potential economic or reliability benefits associated with the hydrogen component of OCAPS.

Proposed Conditions

106. ETI estimated that OCAPS would cost $1.19 billion when it filed its application.

107. OCAPS' total capital cost is subject to escalation both before and after ETI issues a limited notice to proceed.

108. OCAPS' last capital cost estimate of $1.58 billion was completed in June of 2022.

109. The capital cost of OCAPS is expected to exceed $1.58 billion.

110. Without a cost cap, ETI may expend as much as $2.5 billion on the Project.

111. Capping the recoverable cost at $1.37 billion, including the costs for the generation facilities, transmission upgrades, contingencies, and AFUDC, provides a reasonable probability of lowering of costs to consumers over the life of the unit and should be imposed as a condition on the CCN.

112. ETI's proposed hydrogen capability component for OCAPS and any related costs should be rejected.

113. Weatherization of OCAPS to withstand conditions at least as severe as Winter Storm Uri is consistent with reliability needs.

114. Given that the projected fuel savings is based on a reduction in heat rate, the heat rate guarantee in the Engineering, Procurement, and Construction agreement should be adopted.

Effect of Granting the Certificate Amendment on ETI and Any Electric Utility Serving the Proximate Area

115. Operationally, OCAPS will have a positive impact on ETI and its customers in that it will address ETI's need for additional energy, capacity, and reliability.

116. OCAPS will benefit utilities operating in MISO South, including ETEC.

117. OCAPS is expected to reduce locational marginal prices, congestion costs, and reliability-must-run designations and satisfy ETI's reserve requirements.

Other Factors

Community Values

118. The proposed CCN amendment will not result in any adverse effects to community values.

119. The land in the immediate vicinity of OCAPS is already being used for industrial purposes due to the operation of the Sabine Power Station on the site for over 50 years.

Recreational and Park Areas

120. The proposed CCN amendment will not result in any adverse effects to recreational and park areas.

121. No parks or recreational areas are located in the immediate vicinity of the OCAPS site.

Historical and Aesthetic Values

122. Because OCAPS will be located at an existing plant site, the proposed CCN amendment would have no adverse effect on historical values and minimal adverse effect on aesthetic values.

Environmental Integrity

123. OCAPS is expected to have a minimal effect on the environmental integrity of the area.

124. No federally protected species or critical habitats occur on the proposed facility's site.

125. OCAPS will employ state-of-the-art emission reduction controls, including selective catalytic reduction technology and dry low-nitrogen oxides burners to reduce nitrogen oxide emissions, and an oxidation catalyst for the control of carbon monoxide and volatile organic compounds emissions.

Probable Lowering of Cost

126. To model the projected savings to customers, ETI performed several economic analyses comparing OCAPS to three combustion turbine generators.

127. With the cost cap in Finding of Fact No. 111, the proposed CCN amendment will result in the probable lowering of cost to consumers in the area.

128. Across a range of reasonable assumptions, OCAPS is expected to provide positive net economic benefits to ETI customers.

129. OCAPS is an economic resource option that will have the probable effect of lowering the cost of service to ETI customers.

Carbon Policy Assumption

130. ETI's reference and high gas cases evaluated the expected customer benefits of OCAPS both with and without a future enforced carbon emission burden (carbon tax).

131. Although it is possible a carbon tax will be imposed in the future, such a tax has not been imposed in the past, and the evidence does not show imposition of such a tax is probable in the future.

132. Including a carbon-tax assumption in the modeling causes the proposed facility to appear more economic than it otherwise would.

133. Natural gas price projections have increased recently.

134. ETI's reference gas case is reasonable despite the carbon tax assumption.

<u>Variable O&M Assumption</u>

135. ETI's Aurora model output assumed that OCAPS and future CCGTs had variable operations and maintenance (O&M) costs that were unreasonably high relative to ETI's projection of OCAPS' O&M costs.

136. ETI estimates variable cost savings to be the difference of the O&M costs from the Aurora model and ETI's own projection.

137. ETI's O&M cost assumptions add significant variable supply cost savings to OCAPS' net benefit.

138. ETI assumes that the O&M for a generic 2x1 CCGT would be unreasonably high relative to those same costs for the OCAPS 2x1 CCGT.

139. If ETI had made reasonable O&M and capital cost assumptions for OCAPS relative to a generic 2x1 CCGT, the resulting energy savings would be lower than shown in ETI's analysis.

140. ETI's variable O&M assumptions are unreasonable.

141. This unreasonable variable O&M assumption was not shown to eliminate all net benefits of the Project.

<u>Probable Improvement of Service</u>

142. OCAPS is designed to enhance the reliable delivery of electric service during severe weather conditions.