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APPLICATION OF ENTERGY TEXAS, INC. TO AMEND ITS CERTIFICATE OF CONVENIENCE AND NECESSITY TO CONSTRUCT ORANGE COUNTY ADVANCED POWER STATION	§ § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

TEXAS INDUSTRIAL ENERGY CONSUMERS' INITIAL BRIEF

July 18, 2022

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GLOSSARY OF ACRONYMS

ALJ	Administrative Law Judge
BP19	2019 Business Plan
BP21	2022 Business Plan
BOT	Build-Own-Transfer
CCGT	Combined-Cycle Gas Turbine
CCN	Certificate of Convenience and Necessity
CoL	Conclusion of Law
Commission or PUC	The Public Utility Commission of Texas
CONE	Cost of New Entry
CT	Combustion Turbine
EIA	Energy Information Administration
EPC	Engineering, Procurement, and Construction
EPE	El Paso Electric Company
EPG	Entergy's Enterprise Planning Group
ETI	Entergy Texas, Inc.
FoF	Finding of Fact
GAAP	Generally Accepted Accounting Principles
IM	Independent Monitor
LCSF	Liberty County Solar Facility
LNTP	Limited Notice to Proceed
MCPS	Montgomery County Power Station
MISO	Midcontinent Independent System Operator
MMBtu	Millions of British Thermal Units

MW	Megawatt
MWh	Megawatt-hour
NPV	Net Present Value
NYMEX	New York Mercantile Exchange
OCAPS	Orange County Advanced Power Station
O&M	Operations & Maintenance
PFD	Proposal for Decision
PPA	Purchased Power Agreement
PRA	Planning Resource Auction
PURA	Public Utility Regulatory Act, Tex. Util. Code §§ 11.001 et seq.
RFP	Request for Proposals
SPS	Southwestern Public Service Company
SWEPCO	Southwestern Electric Power Company
TIEC	Texas Industrial Energy Consumers
VLR	Voltage and Local Reliability

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I. INTRODUCTION

When a utility requests this Commission to approve a $1.2 billion expenditure that, by its own initial estimates, would raise base rates by at least $177 million in the first year alone,[1] one would expect the utility to support that proposal with an economic analysis showing that the proposed plant was better than reasonable alternative courses of action. One would also expect that analysis to be based on the most current information available. Without such a showing, it is difficult to see how a utility could satisfy its statutory burden to prove that the proposed plant is necessary for the service to the public.

In April 2021, there were those at Entergy's Enterprise Planning Group (EPG) that urged that the Orange County Advanced Power Station (OCAPS) [redacted] what emerged a few weeks later was the exact opposite. ETI chose the most uneconomical

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[1] ETI Ex. 11, Lofton Dir. at 4 (Bates 6 of 34).

[2] TIEC Ex. 11 (HSPM) at 2 (Bates 006).

[3] TIEC Ex. 11 (HSPM).

[4] TIEC Ex. 7; Tr. at 156:1-157:24 (Weaver Cross) (CONF) (June 29, 2022).

alternative one could think of—a series of three extraordinarily costly and inefficient hydrogen-enabled peaker plants.[5] This was not an option that had ever appeared in any of ETI's prior analyses, and for good reason. As ETI has admitted, it was not an option that would meet Entergy's needs[6] and it was not an economical source of energy.[7] ETI admitted at the hearing that the new 3-CT alternative it developed for testing the economics of OCAPS was not even designed to identify the best option.[8] This new alternative had one critical feature, however; it would make virtually any other supply option look economical in comparison.[9]

Armed with this new basis for comparison, the Entergy Planning Group presented the ETI Operating Committee and the former CEO with a PowerPoint presentation devoid of any analysis of OCAPS compared to reasonable alternatives.[10] Instead, Entergy's "Updated OCPS Economic Evaluation" for the first time switched to a comparison to hypothetical uneconomic hydrogen-enabled CTs, showing, not surprisingly, that OCAPS would save \$1.5 to \$2.4 billion dollars compared to that uneconomical option.[11] [redacted][12] Instead, the proposed \$1.2 billion CCGT was approved based solely on a comparison to an entirely unrealistic alternative. A few months later, less than a month prior to the filing of this case requesting approval of OCAPS, the Entergy Operating Committee and former ETI CEO also approved the deactivation of the 495-MW 47-year-old Sabine 4 unit in 2026, if and only if the new CCGT was approved, constructed, and on-line by then.[13] Sabine 4 would, in ETI's view, no longer

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5 ETI Ex. 4, Weaver Dir. at ABW-8 at 9 (Bates 255 of 260); Tr. at 160:15-25 (Weaver Cross) (CONF) (June 29, 2022).

6 ETI Ex. 25, Nguyen Reb. at 33-34 (Bates 35-36 of 55).

7 *Id.*

8 Tr. at 414:19-21 (Nguyen Redir.) (June 30, 2022).

9 TIEC Ex. 1, Griffey Dir. at 57 (Bates 060).

10 ETI Ex. 4, Weaver Dir. at ABW-8.

11 ETI Ex. 4, Weaver Dir. at ABW-8 at 9 (Bates 255 of 260).

12 Tr. at 161:6-21 (Weaver Cross) (CONF) (June 29, 2022).

13 ETI Ex. 4, Weaver Dir. at ABW-5 at 8-9, 28 (Bates 50-51, 70 of 260).

be necessary if ETI built OCAPS. And if it did not build OCAPS, the Sabine 4 deactivation decision would be of no effect.[14]

Even at the $1.2 billion level, the construction of OCAPS, while providing over a billion dollars in return on invested capital to ETI,[15] would have been uneconomical, as evidenced by Ms. Lofton's calculation of the Year 1 impact on ratepayers.[16] But the $1.2 billion, which was no more than an estimate to begin with, has proven to be dramatically understated. In April, ETI added another $170 million to the estimate, bringing it to $1.37 billion.[17] Then one month later, ETI added yet another $210 million to the estimate, bringing it to $1.58 billion.[18] And in June, the Entergy Board passed a resolution authorizing a cost of $1.675 billion.[19] Ms. Lofton's estimate of a $177 million rate base increase for Texas ratepayers would become a nearly $250 million increase based on the June estimate approved by the Entergy Board.[20] And none of ETI's cost estimates represent anything but speculation at this point, as the EPC contractor responsible for roughly 70% of the proposed costs does not even have to provide an actual price until after this Commission would have granted the CCN.[21] Even then, the cost could escalate for any number of reasons,[22] and the remaining 30% of the costs not covered by the EPC contract will just be whatever they turn out to be.[23] With escalations of $475 million in just over two months, one can only guess what the price tag might be were the Commission to issue a CCN six months after the latest estimate, let alone when the construction costs are actually incurred as the plant is built.

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[14] *Id.*

[15] TIEC Ex. 1, Griffey Dir. at 9 (Bates 012).

[16] ETI Ex. 11, Lofton Dir. at 5-6 (Bates 7-8 of 34). Ms. Lofton's Year 1 calculations adopted Mr. Nguyen's unrealistic estimate of fuel savings, but still showed that ratepayers would pay substantially higher total rates if OCAPs were built.

[17] ETI Ex. 27, Ruiz Reb. at 3 (Bates 5 of 14).

[18] ETI Ex. 8C (Publlic) at 3; Tr. at 205:1-4 (Ruiz Cross) (June 29, 2022).

[19] ETI Ex. 61.

[20] *See infra* Section IV.A.

[21] *See* Tr. at 32:7-33:18 (Viamontes Cross) (June 29, 2022).

[22] *See infra* Section IV.A.

[23] Tr. at 17:11-17 (Viamontes Cross) (June 29, 2022).

As discussed below, the process that led to the selection of OCAPS was designed in such a way as to exclude any real competitors;[24] Entergy itself was the lone respondent to its own Request for Proposals. Given the complete absence of competition, the high and ever-increasing cost of OCAPS should not come as a surprise. And while Entergy would be given a regulatory return that only grows as the cost escalates, the ratepayers would absorb a massive base rate increase, with little hope that ETI's sales of the output of the facility into the MISO market[25] would result in an adequate offset.

Entergy's OCAPS proposal is the result of (1) a process that systematically excluded competitors and (2) an economic analysis that failed to consider any realistic alternatives. Entergy can offer no assurances about the cost of the proposed plant, and it would not even receive a price from the EPC contractor until after the Commission had already approved the CCN. The Commission rightly requires much more of an applicant for approval of a CCN, and ETI's request should be denied.

II. CERTIFICATE OF CONVENIENCE AND NECESSITY STANDARD (P.O. ISSUE NO. 14)

ETI has the burden of proof in this case.[26] It must prove that its proposed acquisition of OCAPS is necessary for the service, accommodation, convenience, or safety of the public.[27] The Commission is charged with regulating public utilities as a substitute for competition[28] and ensuring that rates are just and reasonable.[29] The requirement that a utility obtain CCN approval before acquiring a new power plant, for which the utility will ultimately seek to charge captive ratepayers, is a core part of that system of regulation.[30] In making its CCN determination, the Commission looks to numerous factors, including whether a proposed acquisition would result in

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[24] *See infra* Section III.B.ii.

[25] Tr. at 165:14-21 (Weaver Cross) (CONF) (June 29, 2022) (acknowledging that "reducing a capacity factor for a unit would mean selling less kilowatt hours into the MISO market," and that "fuel savings come from selling kilowatt hours into the MISO market at a price above LMP.").

[26] PURA § 39.003; *Application of Entergy Texas, Inc. to Amend a Certificate of Convenience and Necessity for the Acquisition of a Solar Facility in Liberty County*, Docket No. 51215, Final Order at CoL 20 (Oct. 19, 2021).

[27] PURA § 37.056; 16 T.A.C. § 25.101.

[28] PURA § 11.002(b).

[29] PURA § 36.003(a).

[30] *See generally* PURA Chapter 37; 16 T.A.C. § 25.101.

the probable improvement of service or lowering of cost.[31] For the reasons set forth below, ETI has failed to meet its burden of proof, and its application should be denied.

III. THE ADEQUACY OF EXISTING SERVICE AND THE NEED FOR ADDITIONAL SERVICE

A. Need for additional capacity (P.O. Issue Nos. 15-18)

ETI projects a need for additional capacity, just as it has in the past.[32] But there are reasons to be skeptical of ETI's projections, and it has not demonstrated that it requires an OCAPS-sized addition in 2026.

ETI's projected capacity need is based on a number of assumptions, including that it will experience dramatic load growth.[33] Notably, however, ETI has previously predicted significant load growth that did not come to pass. In support of its 2015 application to acquire the Union Power Station (Docket No. 43958), ETI projected that its loads would grow by 700 MW by 2023.[34] In fact, ETI referred to this as a conservative estimate.[35] But that growth has not come close to materializing. On a non-coincident peak (NCP) basis, ETI had experienced only approximately 160 MW of load growth as of 2020, and it now projects that its loads will grow by less than 200 MW from 2015 to 2023.[36] On a MISO CP basis, which ETI now uses in its resource planning,[37] ETI's loads actually shrunk by approximately 30 MW from 2015 to 2020, and ETI projects that they will have grown by less than 80 MW from 2015 to 2023.[38] ETI's projections of strong load growth in CCN cases (in which it stands to benefit from showing a need for capacity) should be taken with a grain of salt.

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[31] PURA § 37.056(c).

[32] *E.g.,* TIEC Ex. 8 at 7, FoF 54-55.

[33] TIEC Ex. 1, Griffey Dir. at 36 (Bates 039).

[34] TIEC Ex. 52. at 7; Tr. at 463:23-464:9 (John Recross) (June 30, 2022) (referring to NCP load).

[35] TIEC Ex. 52 at 6, 7.

[36] ETI Ex. 20, John Reb. at WCJ-SD-2 (Bates 15 of 17); Tr. at 464:20-465:13 (John Recross) (June 30, 2022).

[37] ETI Ex. 4, Weaver Dir. at 11.

[38] ETI Ex. 15, John Supp Dir., Exhibit WCJ-SD-2 (Bates 17 of 17). These figures are from ETI's BP 21. The BP 22 projections show that ETI now projects that its loads will have [redacted] in 2023 from 2015. ETI Ex. 29A, Weaver Reb. (HSPM), Exhibit ABW-R-2.

ETI's projected capacity need is also impacted by the other resources it plans to acquire. And since ETI filed this case, its assumptions in that regard have changed. Specifically, ETI latest estimates (BP 22) are that it will add an extra [redacted] between 2025 and 2029 above what had previously been planned, including an additional [redacted] MW in 2025—the year before OCAPS would come on line.[39] ETI's latest Business Plan also shows the addition of [redacted] MW of solar and [redacted] MW of storage capacity from [redacted][40] These new planned additions illustrate the extent to which ETI's projected future capacity situation is in flux and further weaken the case that ETI requires an investment of $1.6 billion or more in 2026 to address a capacity shortfall.

Just as with planned capacity additions, ETI's planned retirements also impact its projected need for additional capacity. ETI's projected capacity need as presented in this case is predicated on the assumption that Sabine 4 will be retired in 2026 (at age 52), the same year that OCAPS would replace it (and at the same site).[41] Sabine 4 is one of five gas-fired steam boiler units at the Sabine site.[42] ETI plans to operate Sabine 4's sister unit Sabine 3 until it reaches a service life of 60 years, [redacted][43] As Mr. Griffey testified, there is no physical reason that Sabine 4 could not also be operated for 60 years assuming proper maintenance.[44] Indeed, ETI evaluated extending Sabine 4's life until 2032 as part of the 2019 Portfolio Analysis that underlies this application, which indicates that ETI itself saw operation of the plant for 60 years as a viable option.[45]

Nevertheless, having decided to move forward with OCAPS, ETI now contends that operating Sabine 4 for 60 years would pose an unacceptable risk.[46] To that end, ETI witness Abigail Weaver testified in rebuttal that Mr. Griffey's suggestion that Sabine 4 could operate for 60 years would be "*unprecedented*," and that *__zero__* natural gas-only steam boiler generators of

[39] TIEC Ex. 1A, Griffey Dir. (HSPM) at 9, 45 (Bates 001, 014)

[40] *Id.* at 46-47 (Bates 015-016).

[41] TIEC Ex. 1, Griffey Dir. at 1,10, 47-48 (Bates 004, 013, 050-051).

[42] *Id.* at 47 (Bates 050).

[43] TIEC Ex. 1A, Griffey Dir. (HSPM) at 47.

[44] *Id.* at 47-48 (Bates 050-051).

[45] TIEC Ex. 1, Griffey Dir. at 14 (Bates 017).

[46] *E.g.,* ETI Ex. 29, Weaver Reb. at 30-32 (Bates 32-34 of 71).

Sabine 4's size (>500 MW) have operated 60 years or more."[47] (emphasis in the original). At the hearing, however, it became clear that Ms. Weaver's testimony was misleading. What she failed to disclose in her rebuttal testimony was that no plants of Sabine 4's size and type have had a chance to operate for 60 years. That is because the oldest of all such plants is only 57 years old.[48] It is unsurprising that Ms. Weaver's testimony on this point was overstated given that, as mentioned above, [redacted]

Indeed, ETI has indicated in a prior CCN case that it "generally assumes a 60-year operational life for solid fuel and steam generators unless evidence suggests a shorter or longer life assumption is appropriate."[49] Further, not only did ETI specifically include a scenario in which Sabine 4 operated for 60 years in its 2019 Portfolio analysis, it also made its decision to retire Sabine 4 in 2026 contingent on OCAPS being constructed.[50] Ultimately, ETI's recent assertion that it would be unreasonably risky to operate Sabine 4 past 2026 simply is not credible.

ETI's need contentions also suffer from additional flaws, including that it used an unreasonably high reserve margin,[51] and that it continues to ignore the availability of capacity in an oversupplied MISO South.[52] The evidence shows that ETI has options to meet its capacity needs other than locking ratepayers into an extremely expensive, long-term investment in 2026. That optionality is particularly valuable in a time of escalating capital costs and market volatility. ETI has not demonstrated that it has a need for OCAPS.

B. Consideration of Alternatives to OCAPS (P.O. Issue Nos. 20)

In every CCN case, the Commission must consider whether the utility has shown that the proposed facility will provide net benefits to customers. For instance, in Entergy's recent LCSF case, the Commission found that ETI would need additional capacity to meet the future needs of its customers, but it denied the CCN because ETI had not shown that the facility would provide

[47] *Id.* at 31 (Bates 33).

[48] Tr. at 696:17-24 (Weaver Cross) (July 1, 2022); TIEC Ex. 64 (HSPM).

[49] TIEC Ex. 52 at Bates 11.

[50] ETI Ex. 4, Weaver Dir. at ABW-5 at 8-9, 28 (Bates 50-51, 70 of 260).

[51] TIEC Ex. 1, Griffey Dir. at 48-50 (Bates 051-053).

[52] *Id.* at 52 (Bates 055).

net benefits to customers[53] or that it would result in the probable lowering of costs to customers.[54] Accordingly, the Commission found that "Entergy did not demonstrate acquisition of the proposed facility is an economic alternative for meeting its capacity, energy, and resource diversity needs."[55]

The question of whether a proposed facility provides net benefits, lowers costs, and is an economic alternative inevitably raises the question: "compared to what?" It is the utility's obligation as the party with the burden of proof to identify alternative courses of action and demonstrate that the proposed plant for which a CCN is sought is superior to those alternatives. ETI has utterly failed to make that showing.

The alternative to which ETI sought to compare OCAPS in its direct case was the construction of three extraordinarily expensive, inefficient, hydrogen-enabled combustion turbines. While OCAPS was in all likelihood cheaper than that alternative, so would be a virtually unlimited number of other options. At a first year cost of [redacted]/MWh[56] and an installed cost of over $1,032/kW,[57] the 3-CT alternative would make even ETI's rejected LCSF proposal look like a bargain.[58] But the question is not whether the utility can identify some alternative that is even worse for ratepayers than what it proposes. It is whether the proposed option is an economical alternative, which necessarily requires a comparison to realistic alternatives.

i. 2019 Portfolio Analysis and updates

With the discreditation of ETI's case for approving OCAPS simply because it was better than a woefully uneconomical 3-CT option, ETI began to shift to arguing that the 2019 Portfolio analysis could justify this project.[59] But that analysis, in addition to being riddled with many of the same methodological flaws the Commission rejected in the LCSF case, is based on stale assumptions and a limited analysis conducted over three years ago. And while Entergy was urged

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[53] TIEC Ex. 8 at FoF 70.

[54] *Id.* at FoF 72.

[55] *Id.* at CoL 17.

[56] TIEC Ex. 1A, Griffey Dir. (HSPM) at 57 (Bates 024).

[57] Tr. at 368:15-21 (Nguyen Cross) (CONF) (June 30, 2022).

[58] The Commission found that the Year 1 costs of the rejected Liberty County project were $92/MWh. TIEC Ex.8 at FoF 63.

[59] Tr. at 414:19-415:14 (Nguyen Redir.) (June 29, 2022).

by members of its own Enterprise Planning Group [redacted]

Some of the reasons that the stale 2019 portfolio analysis cannot now substitute for what should have been a robust comparison to reasonable alternatives are readily apparent. In the first place, the assumptions in the 2019 analysis are simply out-of-date. The portfolio analysis relied on ETI's fuel price and capacity cost assumptions from its 2019 business plan (BP 19)[61] which has now been updated three times. It also relied on ETI's BP 19 expansion plan, which has now been modified to include, among other things, [redacted] to be added this decade, which not only changes ETI's capacity needs but impacts the economic analysis of a proposed CCGT.[62] As low-cost solar power is added to the system it will tend to push old natural gas plants off the system and lower the on-peak market clearing price.[63] Further, the 2019 analysis did not even include a hydrogen-enabled CCGT like OCAPS in its portfolio analysis, as the decision to add hydrogen capacity was not made until 2021.[64]

The testimony of Charles Griffey identifies any number of other flaws with the 2019 analysis, including the assumption of a carbon tax, which the Commission has rejected multiple times, including in the recent LCSF case.[65] In fact, as Mr. Griffey shows, if ETI properly analyzed alternatives in 2019. OCAPS would not have been the lowest cost resource.[66] But even if ETI had shown that OCAPS (without hydrogen capability) was the best choice of the five portfolios based on the facts as they existed in early 2019, that would do nothing to further the case that OCAPS is the best option today. As the Commission stated in the preliminary order, a CCN is issued "based on the facts known at the time of issuance."[67] ETI's reference to its limited 2019 analysis, which did not even include a hydrogen-enabled CCGT, cannot substitute for a robust analysis of the costly hydrogen-enabled OCAPS proposal compared to current viable options

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60 TIEC Ex. 11 (HSPM).

61 *See* Tr. at 403:7-14, 404:7-11 (Nguyen Cross) (CONF) (June 30, 2022).

62 Tr. at 406:21-407:9 (Nguyen Cross) (CONF) (June 30, 2022).

63 *See* TIEC Ex. 1, Griffey Dir. at 100 (Bates 103).

64 ETI Ex. 4A, Weaver Dir. (HSPM), ABW-8 at 1 (Bates 206 of 220).

65 TIEC Ex. 8.

66 TIEC Ex. 1, Griffey Dir. at 10-24 (Bates 013-027).

67 Preliminary Order at 2 (Dec. 16, 2021).

based on the current expected cost of OCAPS, current markets, ETI's current capacity plans, and a current net benefits analysis. And ETI's case is wholly lacking in that regard, as discussed in section V.B. below.

ii. RFP process

ETI's stated purpose for conducting an RFP was to provide a "market test" for the resource that would become OCAPS.[68] However, the RFP resulted in only one bid—the Entergy self-build proposal that was selected.[69] The RFP thus failed on those terms. More importantly, given its limited nature, it also completely failed to evaluate OCAPS against other options to meet any capacity or reliability needs ETI may have. As Mr. Griffey summarized, "[r]ather than market testing OCAPS against the panoply of resources that could meet a capacity need, ETI created a Potemkin village RFP to make it appear that ETI was evaluating alternatives while the RFP design all but guaranteed no else would bid."[70] The flaws in ETI's RFP process are discussed below.

a. The RFP should not have been limited to a CCGT[71] resource and long-term contracts from the same type of source.

A threshold problem with ETI's RFP is that it was limited to long-term resources of a specific type and size. With respect to new projects, the RFP was limited to 1000 to 1200 MW CCGT plants that had to be located at a single site.[72] As to Purchased Power Agreements (PPAs), offers were required to be from the same size and type of source and have a length of at least 10 and no more than 20 years.[73] As Mr. Griffey testified, the RFP parameters thus eliminated almost all existing generation, renewables and demand-side management programs that might have otherwise participated.[74] They also eliminated smaller CCGTs and options shorter than ten years. These restrictions in the RFP unnecessarily limited competition and the consideration of alternatives.

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[68] ETI Ex. 3A, Rainer Dir. (adopted by E. Viamontes) at 17 (Bates 19 of 62).

[69] ETI Ex. 14, Oliver Dir. at 8 (Bates 10 of 122).

[70] TIEC Ex. 1, Griffey Dir. at 45 (Bates 048).

[71] Combined Cycle Gas Turbine Plants.

[72] ETI Ex. 14, Oliver Dir. at 4-5 (Bates 6-7 of 122).

[73] TIEC Ex. 1, Griffey Dir. at 29 (Bates 032).

[74] *Id.* at 34 (Bates 037).

If ETI truly wanted a market test, it could have issued an all-source solicitation and allowed bidders to propose resources of various types, sizes, and contract lengths. For example, El Paso Electric Company (EPE) recently issued an all source requests for proposals that resulted in 59 proposals from 37 bidders who submitted 508 alternative proposal options.[75] According to the Independent Monitor's (IM) report from that RFP, the "proposals submitted represented a diverse range of technologies [] and contract structures, including [PPAs], Tolling options, Build, Own, Transfer options, and equity participation offers for EPE."[76] ETI's RFP, by contrast, resulted in literally no diversity of any kind; only Entergy itself made a proposal.

ETI has not provided any credible reason for limiting the RFP in this fashion. MISO South is oversupplied with capacity, which means that it is possible that a combination of resources (including short- and medium-term options) might more economically meet a capacity need.[77] Further, ETI's insistence on a single resource of at least 1000 MW is based on its contentions that it must retire Sabine 4 in 2026 and that it will experience dramatic load growth.[78] As discussed herein, these contentions are from certain. In any event, ETI's limitations overlook the possibility that it can acquire shorter-term resources and evaluate whether it truly needs a resource of this size in the coming years, rather than locking in an extremely expensive 30-year investment now.[79] But ETI designed its RFP to completely exclude any resources other than a CCGT of at least 1000 MW and PPAs (from such plants) of at least ten years in duration.

Notably a contemporaneous RFP in MISO South demonstrates the folly of ETI's decision to limit its RFP. In February 2020, a group of electric cooperatives in Louisiana (the "1803 Cooperative") issued an RFP for up to 1000 MW of power to be delivered in MISO Load Zone 9 (ETI's load zone).[80] The RFP called for resources to begin delivering power in 2025 and allowed for any time horizons up to 20 years.[81] The 1803 Cooperative RFP resulted in 198 unique offers from 31 bidders, from a range of technologies, including CCGTs, peaking plants, solar, battery

[75] TIEC Ex. 42 at Bates 005.

[76] *Id.*

[77] TIEC Ex. 1, Griffey Dir. at 34 (Bates 037).

[78] *Id.* at 36 (Bates 039).

[79] *Id.*

[80] *Id.* at 32 (Bates 035).

[81] *Id* at 33 (Bates 036).

storage, and various market products.[82] The winning bids included a new 400 MW CCGT, numerous 20-year solar PPAs, a 5-year partial requirements contract, and a 5-year energy purchase with a capacity option.[83] ETI's RFP prevented these types of options from even being considered.

b. The RFP should not have been limited to ETI's "Eastern Region."

Another unnecessary limitation in the RFP was the requirement that the resource be located in what ETI referred to as its "Eastern Region."[84] ETI's service territory is located within the West of Atchafalaya Basin (WOTAB), which is a load pocket.[85] WOTAB, however, contains all of ETI's service territory and also portions of Southwest Louisiana.[86] MISO has operating guides for WOTAB and for the Western Region of ETI's service territory, but it does not have an operating guide for the "Eastern Region" of ETI. Nevertheless, ETI argues that the new resource needed to be sited in the Eastern Region to address voltage (reactive power) and local reliability (VLR) concerns.[87]

When asked to identify a MISO document or transmission operating guide that references the ETI Eastern Region, ETI could only point to the "Western & WOTAB Area Commitment Guide," which refers not to an "Eastern Region" but to a "Sabine Interface."[88] This guide, which sets out MISO's commitment practices to secure the referenced areas from a VLR perspective, defines a "Western Load Pocket Interface" as [redacted][89] However, the document indicates that the [redacted] Moreover, [redacted]

[82] *Id.* at 32 (Bates 035).

[83] *Id.* at 33 (Bates 036).

[84] ETI Ex. 4, Weaver Dir., ABW-6 (Bates 196 of 260).

[85] *Id.* at 26 (Bates 28 of 260).

[86] ETI Ex. 5, Kline Dir. at 6 (Bates 8 of 46), Exhibit DK-2 (Bates 33 of 46).

[87] *Id.*

[88] TIEC Ex. 62 (HSPM). The "Sabine Interface" is defined as a [redacted] *Id.* at Bates 009.

[89] *Id.* at Bates 010.

[90] *Id.* at Bates 009.

[redacted]

Ultimately, ETI has not provided any analysis demonstrating that it requires a plant of OCAPS' size for VLR or transmission reasons in the Eastern Region.[94] Nor has it provided any analysis comparing OCAPS to other options to address these issues. This is telling, particularly since ETI's own [redacted].[95] Any new plant should provide some VLR benefits in the location where it is constructed. But that does not justify building it in the absence of analysis showing how much VLR support is needed and a comparison to other options to provide such support. ETI did not conduct such analyses. Instead it simply excluded all resources from outside its Eastern Region from the RFP.

c. The RFP should not have included lease-accounting provisions that made it practically impossible for a PPA bidder to participate.

The RFP included a provision that gave ETI the unilateral right to terminate a PPA (with a fee to the seller) if the PPA were ever deemed a lease in the future or if a change in accounting guidelines otherwise caused the PPA to become a liability on ETI's books.[96] In other words, even if a PPA was *not* deemed a least at the time of execution, the seller would face the risk that it would be cancelled in the future if a change in accounting guidelines caused the PPA to appear as a debt on ETI's books. ETI was also clear in the RFP process that it would not accept any PPA deemed a lease or debt to be placed on ETI's books at the time of the RFP.[97] As Mr. Griffey explained, these are non-standard PPA provisions, and their impact is to drive away PPA bidders.[98]

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[91] Tr. at 303:11-21 (Kline Cross) (June 30, 2022).

[92] TIEC Ex. 62 at Bates 006.

[93] *Id.*

[94] TIEC Ex. 1, Griffey Dir. at 38 (Bates 041).

[95] TIEC Ex. 59 (HSPM). [redacted] *Id.* at Bates 015.

[96] TIEC Ex. 1, Griffey Dir at 41-43 (Bates 044-046); TIEC Ex. 2, Griffey Supp. Dir. at 2-3 (Bates 004-005).

[97] TIEC Ex. 1, Griffey Dir at 41-43 (Bates 044-046); TIEC Ex. 2, Griffey Supp. Dir. at 2-3 (Bates 004-005).

[98] TIEC Ex. 1, Griffey Dir at 41 (Bates 044).

- ***Termination provision***

The termination provision places unreasonable risk on PPA sellers.[99] PPA sellers rely on the revenue stream that the PPA would provide.[100] And a future change in accounting guidelines is completely outside of a PPA seller's control.[101] Thus, asking PPA providers to accept the risk that a PPA that is *not* deemed a lease at the time of the execution might nonetheless be unilaterally cancelled by ETI in the future (with a penalty to the seller) because of a change in accounting guidelines will be unacceptable to most PPA bidders or render their bids uneconomic as they attempt to price in this risk.[102]

It is also unclear what the impact to ETI and its customers would be if a future change in accounting rules moved an existing PPA on to the balance sheet. As Mr. Griffey testified, the risks associated with a PPA (such as that the counterparty will not perform, that the utility may not recover all of its costs, or that the fixed payments are large relative to a utility's cash flows) are assessed by credit ratings agencies when the PPA is executed.[103] 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.[104] Credit ratings agencies have an obligation to accurately report the risk of a utility, and they are not required to mechanically apply GAAP standards when performing their ratings analyses.[105] Thus it is far from clear that an accounting change that required placing a previously off-balance sheet PPA on the utility's balance sheet would result in a change in credit rating, which is what ETI envisions.[106]

Notably, this same lease-accounting provision was included in ETI's RFP for solar proposals that resulted in the selection of the LCSF.[107] In that RFP, the provision was a major cause of a bidder abandoning the lowest cost PPA in favor of a more expensive build-own-transfer

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[99] *Id.* at 41.

[100] Tr. at 743:14-19 (Nguyen Cross) (July 1, 2022).

[101] TIEC Ex. 1, Griffey Dir at 41 (Bates 044).

[102] *Id.*

[103] TIEC Ex. 2, Griffey Supp. Dir. at 7 (Bates 009).

[104] *Id.*

[105] *Id.* at 5-6 (Bates 007).

[106] *Id.* at 7-8 (Bates 009-010).

[107] TIEC Ex. 1, Griffey Dir. at 41 (Bates 044).

(BOT) option.[108] In the LCSF CCN case (Docket No. 51215), the ALJs concluded that ETI had failed to demonstrate that its insistence on the inclusion of the lease-accounting provision was reasonable.[109] The Commission adopted the PFD and denied the CCN.[110]

ETI attempts to defend its lease provisions, though its efforts miss the mark. ETI witness Ms. Lapson asserted in her rebuttal testimony that credit ratings agencies are required to treat a PPA that is deemed a lease as a component of debt in their ratings analyses.[111] However, she clarified in discovery that the requirement is actually that ratings agencies publish their methodologies and disclose whether they followed them, with the agencies also having discretion to revise their methodologies as necessary.[112] This is consistent with Mr. Griffey's testimony that ratings agencies have discretion to accurately capture utility risks and are not required to rotely apply GAAP standards when doing so would lead to irrational results. Ms. Lapson also admitted in discovery that she is not aware of any instances of PPAs being reclassified as leases since the new accounting standard ASC 842 was implemented.[113]

ETI's attempts to show that the lease-accounting provisions are standard in the industry were similarly unavailing. ETI witness Mr. Nguyen included in his supplemental rebuttal testimony numerous RFPs in an attempt to show that utilities are concerned with bids that could implicate lease accounting treatment.[114] However, ETI was apparently only able to identify one non-ETI utility RFP that prohibited PPAs that would be deemed leases.[115] And ETI could not identify any non-Entergy RFPs that included the termination provision for future accounting

[108] *Id.*

[109] *Id.*; TIEC Ex. 9 at 26-29 (Bates 031-034).

[110] TIEC Ex. 8 at 1 (Bates 001).

[111] ETI Ex. 22, Lapson Reb. at 14 (Bates 16 of 170).

[112] TIEC Ex. 2, Griffey Supp. Dir., Exhibit CSG-S-1 at 2 (Bates 022).

[113] *Id.* at 3 (Bates 023).

[114] ETI Ex. 30, Nguyen Supp. Reb. at 2 (Bates 4 of 159) and PDN-SR-1.

[115] TIEC Ex. 74; ETI identified two RFPs in response to a discovery question asking ETI to cite any clause that states a utility would not enter into a PPA if it were deemed a lease, but the second RFP (for Mississippi Power Company) did not address leases. Id. at subpart b; Tr. at 757:21-758:15 (Nguyen Cross) (July 1, 2022); TIEC Ex. 74 at Bates 005 (showing that variable interest entities are addressed under a different accounting standard that leases).

changes.[116] As Mr. Griffey testified, these are non-standard provisions that favor self-builds over PPAs.[117]

- ***Impact of lease accounting provisions on bidder participation***

While ETI's onerous lease termination provision could certainly be expected to drive down bidder participation, the RFP included another provision that appears to have rendered PPA participation practically impossible. When combined with the other parameters of the RFP, ETI's refusal to accept a PPA that would constitute a lease created a catch-22 situation for bidders. On the one hand, ETI would not accept a PPA that would be deemed a lease; but on the other, ETI structured the RFP such that it was practically guaranteed that any qualifying PPA would constitute a lease. It is thus little wonder that zero PPAs offers were received.

Guidance from accounting firms indicates that the three key characteristics that govern whether a PPA would be considered a lease are (1) whether the PPA comes from an identified asset with no right of substitution for the seller; (2) whether buyer controls dispatch and operation of the asset; and (3) whether the buyer has the right to obtain substantially all of the benefits of the asset.[118] As Mr. Griffey explains in his supplemental testimony, all of these factors are satisfied here.[119] In fact, in response to a discovery response asking whether it was possible for a PPA bid to conform to the RFP's requirements without constituting a lease, ETI identified only the third element of a lease (buyer has right to substantially all of the benefits) as one that could potentially have been avoided under the RFP structure.[120] But the RFP parameters made it commercially infeasible for a bidder to structure a PPA offer such that ETI would not take substantially all of the benefits.

Under accounting guidance, "substantially all" means 90% or more.[121] The RFP required that a PPA offer 1000 to 1200 MW of capacity, meaning that to avoid providing ETI with 90% of the benefits of the contract, the PPA seller's CCGT would have to be at least 1112 MW (for sale

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[116] *Id.*

[117] TIEC Ex. 1, Griffey Dir. at 41 (Bates 044).

[118] TIEC Ex. 2, Griffey Supp. Dir. at 9 (Bates 011).

[119] *Id.* at 9-10 (Bates 011-012).

[120] *Id.* at 11 (Bates 013).

[121] *Id.*

of 1000 MW to ETI, the lower range of the RFP) or 1334 MW (for the upper end of the range).[122] The PPA seller could then theoretically sell the difference (for example, 112 MW at the low end of the range) to another party, and thus only provide 89% of the benefits to ETI while providing 11% to the other party. However, as detailed by Mr. Griffey, that would not be a commercially viable option.[123]

There are two factors that make the approach of selling incremental power to a different party (and thus avoid giving substantially all of the benefits to ETI) unworkable. First, ETI required full dispatch rights over the underlying capacity of the PPA.[124] Second, CCGTs have minimum output levels that are far higher than 11%, and are typically more in the range of 50%.[125] In other words, if a CCGT is operating at all, it will have to operate in the range of 50% of its nameplate capacity; it cannot run at only 11% of its capacity.[126] As a result of these factors, ETI would have the unilateral ability to determine when the plant supplying the PPA operates, meaning that the PPA seller could not offer a firm contract to the 11% party.[127] These constraints would put a PPA seller attempting to avoid lease classification at a major disadvantage in making a competitive bid in the RFP.[128]

In response to Mr. Griffey's detailed testimony on the fact that it would be commercially unrealistic for a PPA seller to avoid giving ETI substantially all of the benefits of the PPA, ETI provided a single Q and A in Mr. Nguyen's supplemental rebuttal testimony.[129] Mr. Nguyen argues that if ETI deemed 89% of a PPA to be economic, it stands to reason that the remaining 11% portion would also be economic.[130] However, this ignores the different position that the seller would be in with respect to the 11%, as discussed above. Mr. Nguyen also disagrees with Mr. Griffey's testimony that the 11% seller would be limited to selling into the real-time market,

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[122] *Id.*

[123] *Id.* at 11-16 (Bates 013-018).

[124] *Id.* at 11 (Bates 013).

[125] *Id.* at 12 (Bates 014).

[126] *Id.*

[127] *Id.* at 12-13 (Bates 014-015).

[128] *Id* at 13 (Bates 015).

[129] TIEC Ex. 30, Nguyen Supp. Reb. at 2-3 (Bates 4-5 of 159).

[130] *Id.*

arguing that the seller could make arrangements with ETI to sell the 11% on the same basis that ETI would bid its 89% share into the market.[131] But, of course, the 11% seller would be limited to doing that when ETI decided that the plant should run. Further, it is unknown what terms ETI would require for this service. In any event, it is clear that the a PPA bidder would be placed at a disadvantage in only being able to offer 89% of a resource to ETI in the RFP.[132] Thus, as Mr. Griffey testified, it would not have been commercially viable for a PPA seller to offer a conforming bid into the RFP while avoiding lease classification. Accordingly, the structure of the RFP practically guaranteed that there would be no PPA bids, which is exactly what happened.

d. ETI should not have included other onerous commercial terms in the PPA.

Even if a PPA bidder could somehow get around the problems with the lease-accounting provisions, it would still have to contend with other unfavorable commercial terms in the RFP. These included:

- A term that unreasonably shifted the risk of regulatory disallowances to bidders;[133] and
- Provisions that allowed ETI to veto the sale of the facility that is the source of the PPA to another utility, an affiliate of another utility, a generation company with more than 1000 MW, and any entity in or that had adverse litigation with Entergy within the last four years.[134]

As Mr. Griffey testified, these provisions are non-standard and would serve to severely restrict interest from PPA bidders.[135]

e. The results of the flawed RFP were predictable: no outside participation.

Given the flaws with ETI's RFP process, it is unsurprising that it failed to attract any outside bids. Notably, the lack of interest was evident during the RFP process itself. Only two

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[131] *Id.* at 3 (Bates 5 of 159).

[132] TIEC Ex. 2, Griffey Supp. Dir. at 14 (Bates 016).

[133] TIEC Ex. 1, Griffey Dir. at 39-40 (Bates 042-043).

[134] *Id.* at 40 (Bates 043).

[135] *Id.* at 39 (Bates 042).

third-parties attended the bidders conference, and neither represented an owner or developer of CCGT capacity.[136] One attendee is associated with an Arkansas asbestos, mold, and fire remediation company, and the other attendee works for a natural gas pipeline company.[137] The ETI self-build team was in attendance at the conference, and would have been aware of the lack of interested competition.[138]

Following the bidders conference, ETI received only one question from a potential bidder, and it was to state that extending the deadline for RFP responses to later in the year would provide a better chance for a reply.[139] Despite the lack of interest, ETI did not restart the RFP process.

This is not the first time that an ETI RFP has failed to attract robust responses. ETI's Independent Monitor (IM) (Wayne Oliver) specifically noted the limited participation in both the LCSF[140] and Montgomery County Power Station (MCPS) RFPs.[141] In fact, the participation in the LCSF RFP, in which ETI received 10 bids from 4 proposed resources, was so limited that the IM suggested cancelling the RFP and restarting it.[142] He only agreed to proceeding because restarting the process would have risked the benefits of solar Investment Tax Credits,[143] which are of course not at issue with respect to OCAPS. Notably, however, and despite the fact that the OCAPS RFP received no outside bids at all, Mr. Oliver did not recommend to Entergy executives that they restart the process here.[144]

Ultimately, the RFP for OCAPS led to the precise result that ETI preordained: the rubberstamping of a resource that ETI had already decided to build. The design of the RFP prevented alternatives from being considered, and given the lack of participation, the RFP did not even truly test whether ETI's proposal to self-build the specified type of CCGT at the specified

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[136] *Id.* (HSPM) at 43 (Bates 046).

[137] *Id.*

[138] *Id.*

[139] *Id.;* ETI Ex. 14, Oliver Dir., Exhibit WJO-3 at 18 (Bates 72 of 122).

[140] TIEC Ex. 46 at Bates 005.

[141] TIEC Ex. 47 at Bates 006.

[142] TIEC Ex. 9 at 90, FoF 48 (Bates 095).

[143] *Id.*

[144] Tr. at 256:17-257:1 (Oliver Cross) (June 29, 2022).

location was competitive. Having failed to compare OCAPS to alternative sources to meet any capacity and reliability needs it may have, ETI cannot demonstrate that the plant is necessary.

iii. Other issues regarding alternatives

See section V(b) below.

IV. DESCRIPTION AND COST OF OCAPS AND RELATED FACILITIES (P.O. ISSUE NOS. 2-6, 22-23)

A. Introduction

OCAPS' cost is one of the most important parts of ETI's application. The cost of OCAPS is subject to change and, given rampant escalation, will likely be substantially higher than it was in May when ETI filed its last estimate. Even after Limited Notice to Proceed (LNTP) issuance, the cost of OCAPS is likely to increase. As explained in detail below, force majeure events, which have already occurred, may lead to even higher prices, [redacted].[145] Indeed, ETI's cost estimates have proven so unreliable to date that it has needed to increase them three times in the last three months. Exemplifying the unreliability of ETI's cost projections, when Mr. Griffey concluded that OCAPS could cost \$1.61 billion or more in his rebuttal testimony, Mr. Ruiz called that figure "significantly overstate[d]." Less than three months later, ETI itself forecast the cost of OCAPS to be \$1.58 billion.[146] And, in June, Entergy Corporation approved up to \$1.68 billion for the plant.[147] The ever escalating costs of what was already a too-expensive proposition presents an unreasonable risk to ratepayers.

B. Background

The price of OCAPS is determined by two cost categories: EPC agreement costs and non-EPC costs. EPC costs include certain commodity costs and major equipment such as the turbines.[148] Non-EPC costs include components such as other vendors and expenses, Entergy

[145] ETI Ex. 8A, Ruiz Dir. (HSPM) at Ruiz Supp. Exhibit 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 197:2-13 (Ruiz Cross) (June 29, 2022)

[146] At this time, Mr. Ruiz forecasted OCAPS to cost \$1.37 billion. ETI Ex. 27, Ruiz Reb. at 2 (Bates 4 of 14).

[147] ETI Ex. 61.

[148] Tr. at 193:1318 (Ruiz Cross) (June 29, 2022).

project management, AFUDC, regulatory, transmission upgrades, and project contingency.[149] In ETI's Third Periodic Report on Market Escalation, EPC costs comprised 71% of the total estimate, with non-EPC costs comprising the remaining 29%.[150] However, the final breakdown between these two categories would not be known until the costs were actually incurred.

While ETI has argued that project construction costs are "mainly" fixed,[151] the reality is that both EPC and non-EPC costs can escalate significantly, just as they have. As an initial matter, the non-EPC costs are not fixed whatsoever.[152] These costs will simply be whatever they turn out to be at the time of construction. Moreover, while the EPC costs are subject to contractual provisions, they too can continue to escalate both up to the point of the LNTP and, as described further below, after that point based on certain conditions. Indeed, ETI's CEO, Eliecer Viamontes, confirmed at hearing that part of the risk of OCAPS is that there is no way of knowing what the price of the EPC agreement will ultimately be.[153] The EPC agreement price can be amended, or "trued-up," for escalation at the request of the EPC "Contractor" before LNTP issuance.[154] Part of that true-up will be based on risk of [redacted] escalation that will impact procurement costs.[155] Thus, the EPC costs are not truly fixed at all up until the point that the LNTP is issued.

Following LNTP issuance, the cost of the EPC agreement may continue to climb.[156] For instance, change orders, discovery of new facts, and force majeure events that lead to escalation could increase the final price.[157] [redacted]

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[149] Tr. at 201:25-203:5 (Ruiz Cross) (June 29, 2022) ; ETI Ex. 8, Ruiz. Dir at 18-19 (Bates 21-22 of 64).

[150] *Id.*

[151] ETI Ex. 8, Ruiz Dir. at 14 (Bates 17 of 64).

[152] *Id.*

[153] Tr. at 28:21-23 (Viamontes Cross) (June 29, 2022).

[154] Tr. at 186:2-10 (Ruiz Cross) (June 29, 2022); ETI Ex. 8A, Ruiz Dir. (HSPM) at Ruiz Supp. Exhibit CR-8 (Bates 52 of 2120), Sec. 3.3 [redacted] *see also* Tr. at 185:9-200:19 (Ruiz Cross) (June 29, 2022). [redacted] (which Mr. Ruiz testified they would be). Tr. at 187:20-22 (Ruiz Cross) (June 29, 2022).

[155] ETI Ex. 8A, Ruiz Dir. (HSPM) at Ruiz Supp. Exhibit CR-8 (Bates 1610 of 2120) [redacted]

[156] Tr. at 195:23-196:2 (Ruiz Cross) (June 29, 2022).

[157] Tr. at 195:13-22, 196:17-22 (Ruiz Cross) (June 29, 2022).

[redacted].[158] ETI's witness Carlos Ruiz testified at hearing that force majeure events have already occurred and increased the cost of OCAPS,[159] and some force majeure events (like the war in Ukraine) are still occurring.[160] The force majeure clause alone makes the cost of OCAPS highly uncertain.

C. OCAPS Cost Will Continue to Rise

ETI's cost forecasts have been wrong time and time again. Mr. Ruiz initially testified that the cost of OCAPS would fall before LNTP issuance.[161] But ETI has increased its cost forecast three times since ETI filed its application less than one year ago. In September of 2021, ETI filed its application showing a forecasted cost of $1.19 billion.[162] In February of 2022, ETI filed its First Periodic Report on Market Escalation, showing that the cost of OCAPS had escalated.[163] Mr. Ruiz's rebuttal testimony then raised ETI's forecast to $1.37 billion.[164] Three months later, ETI increased that figure to $1.58 billion,[165] including $91 million for the hydrogen option.[166] In June, Entergy's board approved the cost of OCAPS up to $1.68 billion—41% higher than ETI's initial forecast.[167]

At the hearing, Mr. Ruiz testified that he expects the cost of OCAPS to continue to rise even further before the issuance of a LNTP.[168] Mr. Viamontes likewise testified that we are in

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158 ETI Ex. 8A, Ruiz Dir. (HSPM) at Ruiz Supp. Exhibit 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 197:2-13 (Ruiz Cross) (June 29, 2022).

159 Tr. at 239:7-13 (Ruiz Cross) (June 29, 2022).

160 Tr. at 239:7-13 (Ruiz Cross).

161 ETI Ex. 8, Ruiz Dir. at 37 (Bates 40 of 64) ("ETI and the EPC Consortium expect the currently elevated materials and major component prices to decline between now and the issuance of LNTP.").

162 ETI Ex. 7, Nguyen Dir. at 23 (Bates 25 of 136).

163 ETI Ex. 8B.

164 ETI Ex. 27, Ruiz Reb. at 2 (Bates 5 of 14).

165 ETI Ex. 8C.

166 Tr. at 200:25-201:16 (Ruiz Cross) (June 29, 2022).

167 *See* ETI Ex. 61.

168 Tr. at 205:9-12 (Ruiz Cross) (June 29, 2022).

"uncharted territory" in terms of possible cost escalations through the rest of 2022,[169] due in part to the effects of inflation (which is the highest that it has been since the 1980s), the war in Ukraine, and supply chain issues.[170] The cost of OCAPS is indeed not fixed in any reliable manner.

D. Timeline

ETI's application claims that OCAPS would enter service in the first half of 2026.[171] But prediction is highly uncertain. If ETI selects the hydrogen option and issues the LNTP after October 3, 2022, or if ETI does not select the hydrogen option and issues the LNTP after November 1, 2022, the [redacted].[172] ETI's own witness agrees that ETI won't issue a LNTP by October 3 if this case is litigated,[173] and it is unlikely that ETI issues a LNTP before November 1 either, given the timeline in this case, which was delayed by two months at ETI's request.[174] If the Proposal for Decision is filed two months after reply briefs, parties are granted five weeks to file exceptions and another week to file replies to exceptions (as in the recent Entergy CCN case in Docket Number 51215), and the Commission issues a final order roughly six weeks after that (as in Docket Number 51215), approval of ETI's application (and therefor ETI's LNTP issuance) would not occur until 2023 and OCAPS' in-service date could be pushed into [redacted] OCAPS' uncertain timeline risks further price escalation and uncertainty, making the cost of OCAPS even less predictable.

V. 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)

The addition of any new resource will in some sense enhance reliability, as it will add more capacity to a utility's system. For instance, the Commission found that ETI's rejected LCSF

[169] Tr. at 39:8-18 (Viamontes Cross) (June 29, 2022).

[170] Tr. at 18:19-19:3, 39:8-18 (Viamontes Cross) (June 29, 2022).

[171] ETI Ex. 3A, Rainer Dir. at 9 (Bates 11 of 62); ETI Ex. 10, Sperandeo Dir. at 6 (Bates 8 of 12).

[172] *See* Tr. at 219:8-220:11 (Ruiz Cross) (Jun. 29, 2022); ETI Ex. 8A, Ruiz Dir. (HSPM) at Ruiz Supp. Exhibit CR-8, Exhibit S at Section 1.45 (Bates 1987 of 2120).

[173] Tr. at 181:20-23 (Ruiz Cross) (June 29, 2022).

[174] Unopposed Motion to Modify the Procedural Schedule (Apr. 26, 2022).

facility would have enhanced reliability.[175] The same could have been said about the thousand plus MWs SWEPCO proposed to add in each of its recent CCN cases, but the Commission rejected SWEPCO's proposal in each case.[176] If a plant will be available sometimes to provide electricity, it will in a general sense enhance reliability. But the critical question is not whether the plant will sometimes provide electricity, but will it do so economically and in a way that the utility has shown would be superior to other alternatives. In the LCSF case and the SWEPCO wind cases, the Commission properly found that the proposed plants would not. The same is true with respect to OCAPS.

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

i. ETI's Comparison of OCAPS to the alternative of building three costly and inefficient hydrogen-enabled CTs is meaningless.

ETI's Economic Evaluation of OCAPS was contained in Sections III (Economic Evaluation for the 2020 ETI RFP)[177] and V (Updated OCAPS Economic Evaluation)[178] of the direct testimony of Mr. Nguyen, who is responsible for conducting the economic and financial evaluations of generation resources for Entergy.[179]

There are numerous shortcomings with the economic evaluation ETI presented, but one stands above all; ETI chose to justify OCAPS by showing that it was less expensive than a completely unreasonable alternative of constructing three large and inefficient hydrogen-enabled combustion turbines that somehow have higher capital costs per kW than a hydrogen-enabled CCGT. As Mr Nguyen admitted, the fact that a chosen alternative is less expensive than his 3-CT benchmark does not mean it is less expensive than other alternatives:

[redacted]

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[175] TIEC Ex. 8 at FoFs 58-61.

[176] Docket No. 47461, Order at Ordering Paragraph 1 (Aug. 13, 2018); Docket No. 49737, Order at Ordering Paragraph 2 (July 6, 2020).

[177] ETI Ex. 7, Nguyen Dir. at 13-20 (Bates 15-22 of 136).

[178] ETI Ex. 7, Nguyen Dir. at 22-25 (Bates 24-27 of 136).

[179] ETI Ex. 7, Nguyen Dir. at 1 (Bates 3 of 136).

[redacted]

Mr. Nguyen even admitted that the "3 CT comparison is not intended to identify the best option to serve load."[181] That is, ETI's chosen methodology to present to the Commission in support of the OCAPS proposal actually provides no evidence of whether OCAPS is the right choice, only that it is better than an unrealistic choice. In fact, ETI's entire economic evaluation in Mr. Nguyen's testimony is built on a comparison to an alternative that is so uneconomical that any of the alternative portfolios ETI reviewed in 2019 would be shown as providing massive benefits in comparison.[182] ETI does not pretend that the alternative to constructing OCAPS is

[180] Tr. at 376:13-22 (Nguyen Cross) (CONF) (June 30, 2022); Tr. at 379:22-380:12 (Nguyen Cross) (CONF) (June 30, 2022).

[181] Tr. at 414:19-22 (Nguyen Redir.) (June 30, 2022).

[182] TIEC Ex. 1, Griffey Dir. at 57 (Bates 060).

actually the 3-CT option it uses as a basis for comparison. ETI admitted that "the three CTs do not represent a portfolio that would meet the needs of its customers" and that "the CTs are not an economic energy source."[183] In fact, it seems that the only thing the 3-CT portfolio has to commend it is that it is more expensive than virtually any other alternative.[184] If that were a sufficient showing to support a CCN, this Commission would never have rejected ETI's recent LCSF proposal or SWEPCO's uneconomic wind proposals.

Not only is the 3-CT option an absurd benchmark for determining the prudence of a generation proposal, but ETI compounds the error by piling on a series of unrealistic assumptions. First, Mr. Nguyen has assumed a cost per kW for a CT that is even greater than the cost per kW of OCAPS. OCAPS would be a base load plant that would operate, according to ETI, [redacted].[185] The 3-CTs Mr. Nguyen uses for a comparison are inefficient >9000 Btu/KWh heat rate facilities that would operate only [redacted] of the time.[186] The combustion turbines from the 3-CT alternative are precisely the same type of combustion turbines used in OCAPS, just without all of the additional equipment necessary to create a CCGT. As Mr. Griffey notes in his testimony, to have a CT cost more on a per kW basis than a CCGT is completely unrealistic and contrary to utility experience.[187] [redacted]

In what Mr. Nguyen calls his updated analysis in Section V of his testimony, he continues the absurdity of his analysis to by adding expensive hydrogen capability to peaker plants that will

[183] ETI Ex. 25, Nguyen Reb. at 33-34 (Bates 35-36 of 55).

[184] TIEC Ex. 1, Griffey Dir. at 59 (Bates 062).

[185] Tr. at 373:12-24 (Nguyen Cross) (CONF) (June 30, 2022).

[186] Tr. at 368:15-369:9 (Nguyen Cross) (CONF) (June 30, 2022); TIEC Ex. 1, Griffey Dir. (HSPM) at 80 (Bates 050).

[187] TIEC Ex. 1, Griffey Dir. at 58 (Bates 061).

[188] Tr. at 368:15-21 (Nguyen Cross) (June 30, 2022)

[189] *Id.* at 366:25-369:14.

[190] TIEC Ex. 65 at 9.

operate as little as [redacted] of the hours in a year.[191] Mr. Nguyen made that decision himself,[192] without any economic analysis of whether adding expensive hydrogen capacity to a peaker plant would make sense,[193] or even knowing if anyone had ever decided to add hydrogen capability to a CT.[194]

As noted in the testimony of Charles Griffey, ETI inflated the cost of the 3-CT option in a number of other ways. First, ETI's economic evaluation assumes that the 3-CTs would have fixed O&M of [redacted] in its generic analysis.[195] ETI offered no explanation other than that it consulted with an unnamed construction company to get new assumptions.[196] Second, ETI has more than doubled the fixed fuel demand charge attributable to a CT from what it assumed in its 2019 analysis.[197] 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. ETI offered no explanation for this other than to admit that the transmission costs were the same.[198] ETI chose not to ask Mr. Griffey a single question about these issues at the hearing.

The end result of ETI's choice of an entirely unrealistic generation option, combined with layering on a serious of faulty assumptions to further inflate the cost is exactly what one would expect—an alternative that is so expensive that it would make any other option look good. [redacted] In comparison, the Year 1 cost of ETI's proposed Liberty County facility that the Commission rejected last year was $92/MWh.[200]

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[191] Tr. 365:4-8 (Nguyen Cross) June 29, 2022) (CONF); TIEC Ex. 1, Griffey Dir. (HSPM) at 80 (Bates 036).

[192] Tr. at 364:17-19 (Nguyen Cross) (CONF) (June 30, 2022).

[193] Tr. at 365:25-366:11 (Nguyen Cross) (CONF) (June 30, 2022).

[194] Tr. at 364:20-22 (Nguyen Cross) (CONF) (June 30, 2022).

[195] TIEC Ex. 1A, Griffey Dir. (HSPM) at 59 (Bates 025).

[196] ETI Ex. 25, Nguyen Reb. at 36 (Bates 38 of 55).

[197] TIEC Ex. 1, Griffey Dir. at 59 (Bates 062).

[198] ETI. Ex. 25, Nguyen Reb. at 36 (Bates 35 of 55).

[199] Tr. at 389:14-390:23 (Nguyen Cross) (CONF) (June 20, 2022); *See also* TIEC Ex. 1A, Griffey Dir. (HSPM) at 57 (Bates 024), calculating the total cost including fuel of [redacted]/MWh.

[200] TIEC Ex. 8 at 8 (Bates 008).

In addition to the unrealistic assumptions to overstate the cost of ETI's chosen alternative to OCAPS, ETI makes numerous erroneous assumptions in Mr. Nguyen's economic analysis that understate the cost of OCAPS. First, of course is the fact that Mr. Nguyen's analyses are all based on cost estimates for OCAPS that are now out-of-date and dramatically understated. Despite knowing the cost estimate was anything but fixed, ETI chose not to provide any sensitivity analyses in its direct case applying different potential costs for OCAPS.

Second, ETI understates the cost of capital that would be applied to whatever the cost of OCAPS might turn out to be. ETI's assumed cost of debt through 2056 is 3.53%,[201] without any analysis of whether that is a reasonable cost of debt to assume over the next 34 years, particularly given that the well-known recent increases in debt costs. Mr. Nguyen then combines that low cost of debt with a 9.65 ROE to yield a discount rate of only 6.03% for analyzing the future costs and benefits in his analysis.[202] Again, Mr. Nguyen is unable to support the reasonableness of that calculation. ETI filed a rate case on the last day of the hearing in this case, but did not provide its view on what would be a reasonable cost of capital in that case and did not have a frame of reference for assessing whether the cost of capital used in ETI's analysis in support of OCAPS was reasonable at this time.[203] For a capital-intensive project like OCAPS, using an outdated assumption that lowers the cost of capital will necessarily lower the assumed cost of the facility over its proposed 30 year life and make it appear more economical.

Finally, more than $1 billion dollars (nominal) of the economic benefit of OCAPS in Mr. Nguyen's analysis occurs between 2050 and 2056.[204] Mr. Nguyen's analysis assumes that ETI will be burning natural gas during this period,[205] even though ETI has a widely publicized commitment to being Net Zero in carbon emissions by 2050.[206] ETI offers no analysis of the cost of OCAPS if it had to be retired after 24 years to meet this goal, (which would cause the cost of

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

[202] TR 359:16-360-10

[203] Tr. at 61:10-15 (Viamontes Cross) (June 29, 2022).

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

[205] *See* Tr. at 69:23-70:1 (Viamontes Cross) (June 29, 2022).

[206] TIEC Ex. 30.

the facility to be spread over 20% fewer years), or the cost of whatever it might take to switch to a carbon-free fuel if one is available, or to capture and store the carbon from OCAPS, or to take whatever steps it might need to take to somehow allow OCAPS to continue operating past 2050. There may be a way to achieve that, but it would likely be far from free, and it is completely missing from ETI's economic analysis.

The decision to abandon any comparison of OCAPS to realistic alternatives and to instead use the hydrogen-enabled CTs as a basis for comparison was made despite pleas from Entergy's Enterprise Planning Group to [redacted]

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[207] TIEC Ex. 11 (HSPM) at 3 (Bates 006).

[208] TIEC Ex. 12 (HSPM) at 8 (Bates 011).

[redacted] The results of that analysis were asked for but never produced in this case,[210] and any analysis of the prudence of OCAPS as compared to viable alternatives disappeared. [redacted] the Entergy Operating Committee was provided only the comparison to an unrealistic and inflated 3-CT scenario.[212]

As the party with the burden of proof in this case, one would expect ETI to show the Commission that the proposed option was more reasonable than other viable alternatives, if indeed that could be shown. But ETI abandoned any attempt to present either its Operating Committee or the Commission with a realistic benchmark against which to judge the prudence of OCAPS, and instead presented a comparison to a fanciful proposal that ETI admits is not intended to identify the best option to serve load.[213] ETI then compounded that error by using outdated and unrealistic assumptions concerning the cost of OCAPS. ETI has failed to meet its burden of proof to demonstrate that OCAPS is economical compared to reasonable alternatives.

ii. Additional Flaws in the Economic Evaluation

- ***ETI Overstates OCAPS' Capacity Factors***

In the last 30 years, we've witnessed the development of solar resources, wind resources, batteries, and great improvements in the heat rate of CCGTs, as well as horizontal drilling and fracking—it can be safely assumed that technology has and will continue to advance. But ETI myopically assumes no technological advancement in its economic modeling.

ETI forecasts that OCAPS would operate at or above an [redacted] capacity factor throughout its life, and at roughly [redacted] in ETI's reference case.[214] ETI's witness admitted that its projected

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[209] TIEC Ex. 12 (HSPM) at 13 (Bates 016).

[210] Tr. at 175:20-176:21 (Weaver Cross) (June 29, 2022).

[211] TIEC Ex. 11 (HSPM) at 3 (Bates 006).

[212] Tr. at 160:14-165:15 (Weaver Cross) (CONF) (June 29, 2022).

[213] Tr. at 414:13-21 (Nguyen Redir.) (June 30, 2022).

[214] TIEC Ex. 1A, Griffey Dir. (HSPM) at 60 (Bates 026).

capacity factors from the 2030s to the 2050s are very high.[215] ETI projected [redacted] capacity factors [redacted] for its Montgomery County Power Station (MCPS) when it sought to amend its CCN five years ago.[216] But Montgomery County Power Station (MCPS) is [redacted][217] Thus, ETI now projects that MCPS's capacity factor will be roughly [redacted] than its original projection in year five of MCPS's life, and [redacted].[218]

ETI's forecasted capacity factors for OCAPS are overstated for the same reason they were overstated in ETI's analysis of MCPS: ETI's analyses don't take into account advances in technology that drive down the cost of power, making older plants uneconomical to run as much as ETI expects.[219] ETI says that assuming future improvements in heat rates for new CCGTs is speculative, even as ETI admits that heat rates have declined over the last 20 years and dropped by [redacted] over the last 30 years.[220] And ETI projects that no other CCGT installed in MISO South after OCAPS will have a heat rate as efficient as OCAPS.[221] None of these assumptions are reasonable 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 (depressing projected energy cost savings).[222]

- ***ETI's Power Price Projections are inflated***

In its Final Order in ETI's most recent CCN proceeding, Docket No. 51215, the Commission stated: "Entergy's assumptions regarding the future generation mix in MISO South do not account for the likelihood that additional renewable generation and technological

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[215] Tr. at 108:2-6 (Weaver Cross) (June 29, 2022).

[216] Tr. at 131:16-132:21 (Weaver Cross) (CONF) (June 29, 2022); TIEC Ex. 33 at TP-52487-00TIE003-X004_HSPM MCPS (HSPM).

[217] Tr. at 163:14-24 (Weaver Cross) (CONF) (June 29, 2022); TIEC Ex. 34.

[218] TIEC Ex. 1A, Griffey Dir. (HSPM) at 60-61 (Bates 026-027).

[219] *Id.* at 61 (Bates 027).

[220] *Id.* at 60-61 (Bates 026-27).

[221] TIEC Ex. 1, Griffey Dir. at 62, 64 (Bates 028, 030).

[222] TIEC Ex. 1, Griffey Dir. at 60 (Bates 026).

improvements will result in lower power prices."[223] The same is true of ETI's assumptions in the instant case.

Entergy unreasonably assumes that OCAPS' heat rate advantage relative to other resources in the market will [redacted] through 2040 and then [redacted] from 2040 through 2056.[224]

[redacted]

For ETI's heat rate to [redacted] over time relative to other resources in the market, higher marginal cost units would need to be added to the market over time.[226] But the opposite is true—the general progression of technological advancement means that lower marginal cost units with *lower* heat rates are added over time.[227] And given the various Entergy operating companies' goals of achieving net-zero carbon by 2050,[228] it's likely that MISO South will see additional renewable

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[223] TIEC Ex. 8 at FoF 107.

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

[225] *Id.* at 65 (Bates 031).

[226] *Id.*

[227] *Id.* at 66 (Bates 032).

[228] TIEC Ex. 30.

penetration beyond 2040 that will likewise drive down OCAPS' energy savings.

Given the absurdity of assuming that OCAPS will have an [redacted] relative heat rate advantage for decades and then that OCAPS' heat rate advantage will [redacted] from 2040 to 2056, one must question to what extent ETI's assumptions overstate ETI's calculation of variable cost savings. According to Mr. Griffey's analysis, correcting ETI's erroneous heat rate assumptions would reduce the variable supply cost savings by 22% (or [redacted] million) in the Reference case and 40% (or [redacted] million) in the Low Gas case.[229]

- ***Natural Gas Prices***

Natural gas assumptions are not as important in the instant case as they have been in past CCN cases, such as the Liberty County Solar Facility case. In renewable CCN cases, the renewable project avoids the full amount of the gas used by the units setting the price of energy. But OCAPS would use gas.[230] OCAPS only saves gas to the extent that its heat rate is lower than the heat rates of the units setting the price of power. ETI's projections are that initially OCAPS will save only about 2 MMBtu per MWh compared to those units, while a renewable plant avoids the full amount of gas, roughly [redacted].[231] Thus, compared to a renewable CCN, in this case gas prices have approximately [redacted] of the impact.[232]

ETI modeled three natural gas price cases in its economic modeling: High Gas, Reference Gas, and Low Gas.[233] ETI's High Gas case is inflated and unreliable.[234] History shows that natural gas prices are volatile and can be lower than expected. For example, the shale gas revolution

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[229] TIEC Ex. 1, Griffey Dir. at 66 (Bates 069); *see* ETI Ex. 7A, 52487 Nguyen WP1_Exhibit PDN-3 OCAPS Economic Eval Model Ref Gas Ref CO2_HSPM at Net Benefits Calculations tab and ETI Ex. 7A, 52487 Nguyen WP3_Exhibit PDN-3 OCAPS Economic Eval Model Low Gas No CO2_HSPM at Net Benefits Calculations tab [redacted]).

[230] With the hydrogen option, ETI would have the ability to co-fire 30 percent hydrogen, but it may never convert OCAPS to 100 percent hydrogen firing.

[231] *See* TIEC Ex. 1A, Griffey Dir. (HSPM) at 63, Figure 15 (Bates 043), 65, Figure 16 (Bates 031). The [redacted] MMBtu per MWh is derived from OCAPS' heat rate of roughly [redacted] plus the [redacted] MMBtu that ETI projects OCAPS would save.

[232] [redacted].

[233] TIEC Ex. 1, Griffey Dir. at 67-68 (Bates 070-071).

[234] *See* Tr. at 520:5-9 (Griffey Redir.) (June 30, 2022); ETI Ex. 9, Saxton Dir., Exhibit DS-1 at 13 (Bates 39 of 114).

caused gas prices to fall unexpectedly.[235] That has caused EIA's High Supply case to be the most accurate in recent years, as the Commission has repeatedly found.[236] Since ETI's Low Gas case is relatively close to the EIA high supply case, ETI's Low Gas case is more reasonable than their High Gas case.[237]

But even if gas prices turn out to be "high," ETI's High Gas case is flawed because in that scenario utilities in MISO South (and the rest of the country) would shift to renewables, more advanced technologies, and energy efficiency to mitigate the impacts of higher gas prices.[238] That, in turn, would cause higher heat rate gas plants to be used less often, and gas would be the marginal fuel in fewer hours.[239] But even when CCGTs were on the margin, OCAPS' energy margin would be more constrained than forecast by ETI.[240]

Both ETI's High Gas and Reference Gas cases are also made unreliable by their inclusion of a carbon tax assumption and by not assuming any extension or augmentation of renewable tax credits which, as described below, are not reasonable assumptions.[241]

The accuracy of modeling future gas prices is highly uncertain due to the volatile gas price environment.[242] While industry experts believe gas prices will fall,[243] unstable commodity prices still do not make ETI's economic analysis more reliable. In the face of uncertainty, delaying investment in a new plant until gas prices become more stable and predictable will increase the likelihood that any investment is sensible.[244] If gas prices stabilize at a high level, for instance,

[235] Tr. at 519:9-17 (Griffey Redir.) (June 30, 2022); TIEC Ex. 1, Griffey Dir. at 73 (Bates 076).

[236] TIEC Ex. 1, Griffey Dir. at 69 (Bates 072) (citing Docket No. 51215, Final Order at 11, FoF 87-92; Docket No. 49737, Final Order at FoF 52; Docket No. 47461, Final Order at FoF 89).

[237] Tr. at 519:9-17 (Griffey Redir.) (June 30, 2022).

[238] Tr. at 519:22-520:4 (Griffey Redir.) (June 30, 2022); TIEC Ex. 1, Griffey Dir. at 72 (Bates 075).

[239] *Id.* at 72-23 (Bates 075-076).

[240] Tr. at 520:18-521:3 (Griffey Redir.) (June 30, 2022).

[241] *See* TIEC Ex. 1, Griffey Dir. at 75 (Bates 078).

[242] *See* Tr. at 105:24-106:1 (Weaver Cross) (June 29, 2022), 334:13-16 (Nguyen Cross) (June 30, 2022), 437:24-438:3 (Hebner Cross) (June 30, 2022); TIEC Ex. 1, Griffey Dir. at 102-103 (Bates 105-106).

[243] Tr. at 334:19-22 (Nguyen Cross) (June 30, 2022).

[244] *See* TIEC Ex. 1, Griffey Dir. at 73 (Bates 076).

renewables may be a better investment than a gas and hydrogen-fired CCGT. If gas prices fall, a hydrogen add-on may become an even less economic proposition.

Gas prices have increased since ETI filed its application,[245] but so has OCAPS' price tag[246]—and the cost escalation of OCAPS far outweighs the escalation of purported gas-related benefits.[247] But OCAPS' price escalation is more certain—even ETI predicts that the the plant will now cost at least ~$390 million more than initially forecast.[248] However, gas prices decades from now are highly uncertain—future gas prices could rise or fall. Given the certainty of high construction cost of OCAPS and the uncertainty of future gas prices, the Commission should weigh OCAPS' cost escalation more heavily than speculative future gas prices.

- ***ETI's Carbon Policy Analyses Are Unreasonable***

ETI unreasonably inflated its projected net present value 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 on Entergy.[249] And even though the U.S. has enacted investment and production tax credits for solar and wind energy, which have been extended multiple times and as recently as 2020 with overwhelming bipartisan support, ETI's analysis assigns a zero percent probability to their further extension or augmentation.[250]

Assuming the enactment of a carbon tax and no enactment of a production or investment tax credit contaminate ETI's economic analysis by leading ETI to wrongly assess renewable penetration and by decreasing the value of delaying the procurement or purchase of new generation

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245 Tr. at 333:17-334:2 (Nguyen Cross) (June 30, 2022).

246 *See supra* Section IV.A.

247 The annual revenue requirement of OCAPS has increased from $177 million to $237 million, or about $60 million per year. ETI Ex. 11, Lofton Dir. at 5-6 (Bates 7-8 of 34); TIEC Ex. 1, Griffey Dir. at 9 (Bates 012). Each dollar per MMBtu increase in gas in year one is worth [redacted] per MWh. TIEC Ex. 1A, Griffey Dir. (HSPM) at 65, Figure 16 (Bates 031). Gas prices have increased roughly one dollar per MMBtu. *See* ETI Ex. 36 at "bp 21 nymex eia high supply" tab (showing NYMEX close on June 2027 of roughly [redacted]); TIEC Ex. 1C, Griffey Workpapers (HSPM) at Gas price workpapers HSPM.xlsx [redacted] * 1,158 MW * [redacted] percent capacity factor * 8,760 hours = ~[redacted] million. Application at 1 ("Summer capacity = 1,158 MW."); TIEC Ex. 1A, Griffey Dir. (HSPM) at 60 (Bates 026) (for the capacity factor figure); 8,760 is the number of hours in one year. $60 million is far greater than [redacted] million.

248 ETI Ex. 8C at 3; Tr. at 205:1-4 (Ruiz Cross) (June 29, 2022); ETI Ex. 7, Nguyen Dir. at 23 (Bates 25 of 136). $1.58 billion minus $1.19 billion is $390 million.

249 ETI Ex. 7, Nguyen Dir. at 17-18 (Bates 19-20 of 136); Tr. at 173:20-25, 174:1-3 (Nguyen Recross) (June 20, 2022); Griffey Dir. at 74.

250 TIEC Ex. 1, Griffey Dir. at 74-77 (Bates 077-080).

to take advantage of greater renewable penetration.[251] The end result of ETI's assumptions is to inflate the value of OCAPS relative to alternatives like solar and wind.

- ***ETI Should Not Have Used a Post-Hoc O&M Adjustment***

As discussed above, ETI compares two Aurora model outputs: one with OCAPS and one with 3-CTs. Each output assumed that OCAPS and future CCGTs all had a variable O&M cost of [redacted].[252] But ETI claims that OCAPS' actual expected O&M is just one-fifth of the cost assumed in the Aurora model: [redacted] ETI then claims variably supply cost savings of [redacted] per MWh (the difference between [redacted] and [redacted] per MWh) times the MWh output of OCAPS (since it would be "saving" [redacted] per MWh).[254] By assuming one O&M cost in the Aurora model and expecting another, much lower, O&M cost for OCAPS, ETI added [redacted] million in variable supply cost savings, greatly inflating the purported benefit of OCAPS.[255]

ETI also assumes [redacted] million O&M and capital costs for a generic 2X1 CCGT but just [redacted] million O&M and capital costs for OCAPS without providing any compelling evidence for those numerical differences.[256] ETI's [redacted] O&M discount for OCAPS relative to a generic 2X1 CCGT is especially unreasonable given that OCAPS includes a significant hydrogen investment. ETI's assumption that generic 2X1 CCGT would cost significantly more than OCAPS led ETI to also assume a high market clearing price when generic units set the price, which in turn led ETI to assume that OCAPS would be paid more per MWh, inflating OCAPS' fuel cost savings.[257]

If ETI had treated OCAPS and other 2X1 CCGTs similarly, such as by holding capacity factors constant between OCAPS and other 2X1 CCGTs, ETI would have found that the resulting energy savings are [redacted] million lower (NPV) than shown in ETI's analysis in this case.[258]

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[251] *Id.* at 77 (Bates 080).

[252] TIEC Ex. 1A, Griffey Dir. (HSPM) at 78 (Bates 034).

[253] *Id.*

[254] *Id.*

[255] *Id.*

[256] *Id.* at 79 (Bates 035).

[257] *Id.* at 79-80 (Bates 035-036).

[258] *Id.* at 80-81 (Bates 036-037).

- ***ETI Improperly Inflated OCAPS' Capacity Value***

ETI calculated OCAPS' capacity value by taking the difference between the capacity that would be provided by OCAPS and the capacity that would be provided by an alternative to OCAPS—which ETI unconvincingly concludes would be 3-CTs[259]—and then valuing that amount of avoided capacity at the cost of new entry (CONE).[260] ETI's valuation of CONE is based on ETI's estimate of the levelized cost of a CT, which is significantly overstated given the current CONE in MISO South. ETI's assumptions that 3-CTs are the appropriate alternative to OCAPS, that avoided capacity should be valued at CONE, and ETI's inflated CONE figure all place a heavy finger on the scale of ETI's economic evaluation by unreasonably inflating OCAPS' capacity value.

<u>3-CTs are Not the Appropriate Alternative Capacity Against Which to Measure OCAPS' Capacity</u>

To accurately evaluate capacity benefit, one should compare the capacity of the resource being analyzed to the actual alternative capacity cost that is being avoided.[261] That allows one to understand exactly how much capacity the resource being analyzed offers over the alternative. In this case, ETI should have compared OCAPS' capacity to projected alternative capacity cost that ETI would avoid if OCAPS were to be placed in service.[262] The MISO PRA price is a spot price of capacity, much like ETI's gas price projections are of future spot natural gas prices, and constitutes the actual price of capacity in MISO. Notably, ETI's projections of MISO PRA prices are very low through at least [redacted] However, ETI compared OCAPS' capacity only to 3-CTs, which is not a true alternative to OCAPS, as discussed above. The use of projected MISO PRA prices is appropriate.[264]

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[259] Assuming that the alternative to OCAPS is 3-CTs is unreasonable, as outlined above.

[260] TIEC Ex. 1, Griffey Dir. at 81 (Bates 084).

[261] *See Id.* at Griffey Dir. at 85 (Bates 088).

[262] *Id.* at 85 (Bates 088). MISO's capacity market establishes a price for capacity through the annual PRA, and utilities like ETI can then pay the PRA clearing price for capacity. *Id.* at 81 (Bates 084).

[263] TIEC Ex. 1A, Griffey Dir. (HSPM) at 52 (Bates 020).

[264] TIEC Ex. 1, Griffey Dir. at 85-86 (Bates 088-086).

Capacity Should Not Be Valued at CONE

When a load zone is oversupplied, as it is today, capacity prices are low; at the time Mr. Griffey filed his direct testimony, PRA prices for Zone 9 were $2.88/MW-day and the highest ever recorded is $10/MW-day in planning year 2018-2019.[265] And when supply equals demand in a load zone, PRA prices are capped at MISO's estimate of CONE (based on the capital cost of a new CT, but not a hydrogen-enabled CT) which is currently $229/MW-day.[266]

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 Zone 7 (Michigan), and in Zones 1 through 7 in the most recent auction.[267] 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.[268] ETI should not have assumed that capacity should be valued at CONE when PRA prices are unlikely to rise to that level.

In BP21, one of ETI's two possible forecasts for the PRA projected that PRA prices would reach [redacted].[269] But in order to make that projection, ETI had to make the absurd assumptions that capacity additions in MISO through [redacted] that had not been certified *would not* be activated, but that resources that have not yet been certified for retirement *would* be deactivated.[270] It's irrational to assume that non-certified deactivations will occur but that non-certified activations will not. ETI's disparate treatment of non-certified activations and deactivations makes its assumption that PRA prices could reach [redacted] unreliable. But only through that kind of unreliable analysis could ETI project that PRA prices might reach CONE. ETI simply should not have valued capacity at CONE in this case.

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265 *Id.* at 82 (Bates 085).

266 *Id.* at 81 (Bates 084).

267 *Id.* at 83 (Bates 086).

268 *Id.* at 35, 81-82, Figure 20.

269 TIEC Ex. 1A, Griffey Dir. (HSPM) at 83 (Bates 038).

270 TIEC Ex. 1, Griffey Dir. at 83-84 (Bates 086-087).

ETI's CONE is Improperly Inflated

But even if one could rightly assume that capacity should be valued at CONE, CONE shouldn't be assumed to be over 50% higher than MISO's valuation of CONE.[271] Nonetheless, 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.[272] This is especially absurd given that (in the long run) capacity prices will be capped at the value of CONE minus energy savings.[273]

Instead, ETI could have mimicked its analysis in Docket No. 51215 where, in evaluating whether to extend the life of the proposed Liberty County Solar Facility from 30 to 40 years, ETI conducted a probabilistic analysis of the future price of PRA capacity.[274] This is similar to how ETI projects its future reserve margin to determine how much supply is needed in the market.[275] 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 reduced by NPV [redacted].[276]

Summary of Capacity Value

ETI wrongly based its calculation of capacity benefit on an alternate 3-CTs, improperly assumed capacity value to be based on CONE, and inflated the avoided capacity price itself. ETI has not met its burden of proving that OCAPS' assumed capacity benefit is [redacted] than the [redacted] that Mr. Griffey calculated by using the probabilistic method that ETI utilized in Docket No. 51215.[277]

C. Impact of OCAPS on rates

PURA directs the Commission to consider the probable lowering of costs in deciding whether to grant a CCN,[278] and the Commission has given this factor great weight in ruling on CCN applications. For instance in rejecting ETI's request for a CCN for its proposed Liberty

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[271] *See* TIEC Ex. 65 at Bates 009.

[272] Tr. at 521:4-18 (Griffey Redir.) (June 30, 2022).

[273] Griffey Dir. at 85-86 (Bates 088-089).

[274] *Id.* at 87 (Bates 090).

[275] *Id.*

[276] *Id.* at 88 (Bates 091).

[277] *Id.*

[278] PURA § 37.056(c)(4)(E).

County facility last year, which, as with OCAPS, ETI claimed was necessary for meeting capacity needs, the Commission found as follows:

> The requested CCN amendment would result in probable improvement of service, but would not result in probable lowering of cost to consumers in the area under PURA § 37.056(c)(4)(E).[279]

Similarly, in the 2020 decision rejecting a CCN for SWEPCO notwithstanding SWEPCO's proposal of a capital cost cap and performance guarantees, the Commission found:

> SWEPCO did not establish that the acquisition of the wind generation facilities will result in the probable lowering of cost to customers with or without its proposed guarantees.[280]

And in its 2018 decision denying a CCN for SWEPCO's Wind Catcher project, again despite SWEPCO's proposed cost cap and performance guarantees, the Commission found as follows:

> SWEPCO failed to provide evidence to show it is probable the project would provide a reduction in cost to consumers.[281]

In each case, the utility had submitted an economic analysis purporting to show that the proposed facilities would generate large savings for ratepayers.[282] But, as with ETI's 3-CT analysis in this case, those analyses did not survive scrutiny and could not support a finding that the proposed facilities would result in a probable lowering of costs. Accordingly, those CCN requests were denied.

As with its LCSF proposal, ETI has again failed to meet its burden of proof to show that OCAPS would result in a probable lowering of costs to ratepayers. In fact, ETI has utterly failed to demonstrate what the probable cost of the facility would be, and, unlike other utilities that have come before the Commission seeking a CCN, it has offered no cap on the potential capital cost of

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[279] TIEC Ex. 8 at CoL 16.

[280] *Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization and Related Relief for the Acquisition of Wind Generation Facilities*, Docket No. 49737, Order at FoF 111 (July 6, 2020).

[281] *Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization and Related Relief for the Wind Catcher Energy Connection Project in Oklahoma*, Docket No. 47461, Order at FOF 109A (Aug. 13, 2018).

[282] TIEC Ex. 8 at FoF 66, Docket No. 49737 at FoF 39 (July 6, 2020); Docket No. 47461 at FoF 66-67 (Aug. 13, 2018).

the plant.[283] And in just a matter of months, we have seen ETI's cost estimate rise from $1.19 billion when the case was filed to $1.37 billion in April to $1.58 billion in May.[284] And we learned at the hearing that in June the Entergy Board approved authorizing up to $1.68 billion for OCAPS.[285] In its April rebuttal, ETI ridiculed Mr. Griffey's estimate of $1.61 billion as overstated and unreasonable,[286] yet 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 not-EPC costs alike following the issuance of the notice to proceed.[287]

As ETI has structured this self-build proposal, ETI will not get updated pricing from the EPC contractor until after the Commission issues a CCN.[288] And ETI has vehemently asserted that a cost cap is inappropriate[289] or perhaps unlawful.[290] In fact, it is ETI's position that, once it obtains a CCN from the Commission, it would be entitled to enter into a $2.5 billion contract with the EPC contractor without any further approval from the PUC, if that is what the costs have escalated to.[291] [redacted] ETI candidly admits that there is no way of knowing what the price would ultimately be for the EPC contract, and simply dismisses that uncertainty as "part of the risk."[293] Risk that would be borne by ETI's ratepayers.

[283] Docket No. 49737, Order at FoF 103-104 (July 2, 2020), Docket No. 47461, Order at FoF 122-123 (Aug. 13, 2018); *Application of Southwestern Public Service Company for Approval of Transactions with ESI Energy LLC, and Invenergy Wind Development North America LLC, to Amend a Certificate of Convenience and Necessity for Wind Generation Projects and Associated Facilities in Hale County, Texas and Roosevelt County, New Mexico, and for Related Approvals*, Docket No. 46936, Order at FoF 68-69 (May 25, 2018).

[284] Tr. at 18:4-8 (Viamontes Cross) (June 29, 2022).

[285] ETI Ex. 61.

[286] ETI Ex. 27, Ruiz Reb. at 2 (Bates 4 of 14).

[287] Tr. at 19:4-8 (Viamontes Cross) (June 29, 2022).

[288] Tr. at 28:4-20 (Viamontes Cross) (June 29, 2022).

[289] Tr. at 28:24-29:4 (Viamontes Cross) (June 29, 2022).

[290] ETI Ex. 29, Weaver Reb. at 5 (Bates 7 of 71).

[291] Tr. at 30:7-15 (Viamontes Cross) (June 29, 2022).

[292] TIEC Ex. 4 (HSPM) at Bates 009; Tr. at 37:22-39:7 (Viamontes Cross) (June 29, 2022).

[293] Tr. at 28:21-23 (Viamontes Cross) (June 29, 2022).

It should be noted that the cost of OCAPS is subject to numerous potential increases aside from the continued escalation of costs from the EPC contractor until a Notice to Proceed is issued. Even after that, the EPC costs can escalate 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."[294] In addition, there are numerous other cost that are not covered by the EPC Contract and will just be based on whatever the actual costs turn out to be over the course of construction.[295]

In short, ETI cannot meet its burden to demonstrate the probable lowering of costs to consumers because it simply has no idea where the spiraling costs of OCAPS will end up, and, unlike other utilities, it has steadfastly refused to make any commitments in that regard.

ETI attempted to address the customer impact issue through the testimony of Allison Lofton. What that testimony showed, however, was that even using ETI's original cost of $1.19 billion and its unrealistic assessment of fuel cost savings, OCAPS was not going to provide net benefits to ratepayers any time in the foreseeable future. In Ms. Lofton's direct testimony, she attempted to calculate the impact on customers based on ETI's initial cost estimate, although for some reason ignoring the cost of the required transmission upgrades, reducing the capital cost from the $1.19 billion estimate to $1.1 billion.[296] Even with those erroneous assumptions, Ms. Lofton calculated that the OCAPS facility alone would increase base rates for Texas customers by almost $177 million dollars in Year 1.[297] For comparison's sake, the entire base rate increase for all cost components in ETI's last base rate case in 2018 was $53.2 million.[298]

Faced with the initial increase to the OCAPS cost estimates in April, Ms. Lofton calculated the impact on ratepayers of a $1.3 billion addition to rate base, again excluding the impact of the

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[294] ETI Ex. 8A, Ruiz Dir. (HSPM) at Ruiz Supp. Exhibit 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 197:2-13 (Ruiz Cross) (June 29, 2022).

[295] Tr. at 40:12-23 (Viamontes Cross) (June 29, 2022).

[296] ETI Ex. 11, Lofton Dir. at 4 (Bates 6 of 34).

[297] *Id.*

[298] *Entergy Texas, Inc.'s Statement of Intent and Application for Authority to Change Rates, Docket No. 48371*, Order at FoF 34.

required transmission upgrades.[299] With this assumption, the first year base rate increase required by OCAPS (excluding the transmission upgrade component) was now $201 million.[300] There, Ms. Lofton's analysis of the base rate increase stops. ETI did not introduce any sensitivity runs to show what the customer impact would be if the costs continued to escalate (as they have done). But since the $200 million increase in assumed capital costs for OCAPS from her direct case to her rebuttal case had the effect of increasing the estimated base rate costs to Texas ratepayer by $24 million, it is reasonable to estimate that increasing the costs another $400 million to the roughly $1.7 billion in the June Board resolution would increase the ratepayer base rate impact another $48 million (compared to Ms. Lofton's rebuttal analysis) to $249 million. And increasing the costs by another $800 million to the hypothetical $2.5 billion that Mr. Viamontes believed would be authorized by the Commission's grant of an uncapped CCN would add another $96 million to the estimated costs, for a total of $345 million in Year 1 base rate increases for Texas customers.

Ms. Lofton also included in her testimony a calculation of the fuel cost savings that ETI claims would result from constructing OCAPS.[301] The amount of those projected savings are the same regardless of the capital cost estimate.[302] The first thing to note is that ETI's own projection of fuel savings ($109 million) comes nowhere near offsetting the base rate increase, even using Ms. Lofton's original $1.1 billion cost estimate for OCAPS. Thus even assuming no further escalation beyond the $1.7 billion approved by the Entergy Board in June, the net cost to ratepayers in the first year alone, applying ETI's own inflated projection of fuel savings, would be $140 million, ($249 million base rate increase minus $109 million in projected fuel cost savings).

Further, Ms. Lofton states that she takes her purported fuel savings directly from Mr. Nguyen's economic analysis.[303] Thus, the claimed fuel savings that Ms. Lofton includes are based on Mr. Nguyen's fanciful comparison to the costs resulting from the construction of three

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[299] ETI Ex. 23, Lofton Reb. at 2 (Bates 4 of 11).

[300] Docket No. 48371, Order at FoF 34.

[301] ETI Ex. 11, Lofton Dir. at 6 (Bates 8 of 34); ETI Ex. 23, Lofton Reb. at 4 (Bates 6 of 11).

[302] *Id. Compare* ETI Ex. 11, Lofton Dir. at 6 (Bates 8 of 34) with ETI Ex. 23, Lofton Reb. at 4 (Bates 6 of 11).

[303] ETI Ex. 11, Lofton Dir. at 5 (Bates 7 of 34).

inefficient combustion turbines that would produce electricity at a cost of [redacted]/MWh in Year 1.[304] So not only do the claimed fuel savings come nowhere near offsetting the base rate costs, they are inflated by Mr. Nguyen's comparison to an entirely unrealistic alternative.

Mr. Griffey, on the other hand, presented a comparison over six years using an assumed cost of $1.61 billion for OCAPS.[305] Mr. Griffey's analysis did not correct all of ETI's errors and understates the actual harm to ratepayers from OCAPS, but even with those conservative assumptions the harm to ratepayers through this period is extraordinarily large (over [redacted]), and there is every reason to believe that it would continue.[306]

ETI utterly failed to meet its burden of proof on the issue of the probable lowering of costs to consumers, and the evidence shows that even at the originally estimated cost, OCAPS would be woefully uneconomical for ratepayers. At the current cost estimate, let alone the cost that might ultimately result from the continuing escalations, OCAPS would be an unmitigated economic disaster for ratepayers in Southeast Texas.

VI. ADDITIONAL FACTORS UNDER PURA § 37.056

C. Effect on Ability to Meet Goals Established by PURA § 39.904 (P.O. Issue No. 28)

The Texas Legislature has determined Texas's renewable energy goals,[307] which have already been met.[308] Since hydrogen gas is not a renewable resource, OCAPS would not contribute to Texas's renewable energy goals anyway. Accordingly, this factor does not weigh in support of approving ETI's application for OCAPS.

VII. HYDROGEN CO-FIRING CAPABILITY

A. Costs and Benefits of Dual-Fuel and Fuel Storage Capabilities (P.O. Issue

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304 TIEC Ex. 1A, Griffey Dir. (HSPM) at 57 (Bates 024).

305 TIEC Ex. 1, Griffey Dir. at 91-93 (Bates 094-096).

306 *Id.*

307 PURA § 39.904.

308 TIEC Ex. 1, Griffey Dir. at 96 (Bates 099); *see also* Docket No. 49737, Final Order at FoF 21 (June 6, 2020).

Nos. 23, 27, 39, 41-44)

ETI has not demonstrated that spending an estimated $91 million[309] (and increasing) for a hydrogen technology that will provide unknown, if any, benefit to ratepayers is "necessary for the service, accommodation, convenience, or safety of the public."[310] In fact, Entergy has not done any economic or cost-benefit analysis to justify the cost of OCAPS' hydrogen component.[311]

Entergy has also forgone any forecast for the price of hydrogen on a dollar per mcf or MMBtu basis.[312] Nonetheless, ETI acknowledges that co-firing hydrogen at 30% [redacted] the marginal cost of operating OCAPS. Co-firing at 30% hydrogen would incur a marginal cost of [redacted] (for hydrogen produced from natural gas—also known as "gray hydrogen"—at the lowest price Entergy received a quote for, which assumes $3 per MMBtu natural gas cost) to [redacted] (for hydrogen produced from renewable resources—known as "green hydrogen"—based on Platts Megawatt Daily pricing) per MWh, compared to just [redacted] per MWh for natural gas (also assuming $3/MMBtu natural gas cost).[313] Since ETI never even forecast the price of hydrogen on a dollar per mcf or MMBtu basis, hydrogen could become even less economic in the future.

In addition to [redacted] fuel costs, co-firing hydrogen at 30% would [redacted] the capacity of OCAPS by about [redacted] MW—or [redacted]—compared to firing 100% natural gas, and would [redacted] the heat rate by [redacted] percent.[314] While ETI claims to be in need of additional capacity, it apparently would be happy to sacrifice [redacted] MW if doing so allowed ETI to spend an additional $91 million on an unproven technology.

Without any economic analysis or hydrogen price forecast, all we know is that hydrogen today is [redacted] than natural gas and would [redacted] output of the plant. There is no basis for the Commission to approve hydrogen-related expenditures. And OCAPS would not even

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309 *See* Tr. at 201:3-16 (Ruiz Cross) (Jun. 29, 2022) (stating that as of February 24, 2022 ETI estimated the cost of the hydrogen component to be $91 million).

310 PURA § 37.056.

311 TIEC Ex. 1A, Griffey Dir. at 94 (Bates 045); TIEC Ex. 1B, Griffey Workpapers at 2 (Bates 002).

312 TIEC Ex. 1B, Griffey Workpapers at 5 (Bates 005).

313 TIEC Ex. 1A, Griffey Dir. (HSPM) at 95 (Bates 046); TIEC Ex. 1C, Griffey Workpapers (HSPM) at Bates 013 to 014.

314 TIEC Ex. 1A, Griffey Dir. (HSPM) at 94 (Bates 045).

decrease carbon emissions. While reducing carbon emissions from electric generating plants is an ETI[315]— not a Texas legislative[316]—goal, it is not clear that co-firing hydrogen would reduce carbon emissions. ETI anticipates using hydrogen produced from natural gas upon initial operations.[317] If green hydrogen fails to ever become economical and gray hydrogen is used at OCAPS, ETI's own hydrogen expert believes that it would be expected that there would be no reduction in greenhouse gas emissions and that it wouldn't be surprising for OCAPS to actually increase CO2 emissions.[318] ETI also projects that co-firing gray hydrogen would [redacted] CO2 emissions by either [redacted] on a per MWh basis unless ETI contracts for [redacted]

ETI attempts to justify spending $91 million, or likely more, on hydrogen capability by claiming that hydrogen creates a dual fuel benefit. To determine whether a purported dual fuel benefit justifies the $91 million cost, one would need to compare the dual fuel benefit of hydrogen against other dual fuel capabilities. But ETI performed no such study.[319] Nor did ETI evaluate whether hydrogen provides greater benefit than the existing gas storage at Spindletop, to which OCAPS will be connected,[320] or liquid fuel back-up at OCAPS.[321]

ETI did not meet its burden of proving that there is any benefit to hydrogen capability at this stage in the technology's development. The Commission should reject OCAPS with the $91 million hydrogen component.

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

There are at least two ways in which OCAPS could impede the transition to competition in the future. First, as the estimated cost of OCAPS continues to climb, it becomes increasingly likely

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315 TIEC Ex. 1, Griffey Dir. at 95-96 (Bates 098-099).

316 TIEC Ex. 1, Griffey Dir. at 99 (Bates 102).

317 TIEC Ex. 1, Griffey Dir. at 94 (Bates 097).

318 Tr. at 428:25-429:14 (Hebner Cross) (June 30, 2022).

319 TIEC Ex. 1B, Griffey Workpapers at Bates 017.

320 TIEC Ex. 1, Griffey Dir. at 98 (Bates 101).

321 TIEC Ex. 1, Griffey Dir. at 98 (Bates 101). In fact, hydrogen is not even a requirement of the RFP so it was not competitively bid. TIEC Ex. 1, Griffey Dir. at 29 (Bates 032).

that it would create stranded cost exposure in the future.[322] The increasing build-out of renewable resources could result in an over-supplied MISO market that would make a high-capital-cost plant uneconomic. As Mr. Griffey noted, the stranded cost issues were some of the most difficult issues in the transition to competition in ERCOT.[323] And ratepayers ultimately end up paying for stranded costs.[324]

The second potential impediment to retail competition would be the increased market power in MISO South, where Entergy's market share of excess capacity is projected to be 41%, even without OCAPS.[325] Adding another 1200 MW to Entergy's already large portfolio would only exacerbate the market power situation. Mr. Totten testified for ETI that it would be appropriate to look at all of MISO, not just excess capacity in MISO South in assessing market power. But the determination of the appropriate market will be made by a future Commission based on the facts as they exist at the time, including the ability of potential competitors to deliver power into Texas in particular.[326]

It is impossible to predict the circumstances that will exist when the Commission is ready to transition the ETI area to a competitive market, but allowing the dominant player in the market to add a 1200 MW high-capital-cost plant to its portfolio is unlikely to make the transition easier, and could make it substantially harder.

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

The evidence in this case demonstrates that the OCAPS proposal was developed through an uncompetitive process, was uneconomical at the outset, and has only gotten worse as the projected costs have skyrocketed. This is not a close case that can be rescued by the type of capital cost cap or performance guarantees the Commission has applied in other cases. Further, ETI has made clear that it does not believe cost caps are appropriate.[327]

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[322] TIEC Ex. 1, Griffey Dir. at 100 (Bates 103).

[323] Tr. at 469:23-470:8 (Griffey Direct) (June 30, 2022).

[324] TIEC Ex. 1, Griffey Dir. at 100 (Bates 103).

[325] *Id.*

[326] PURA § 39.152(b); Tr. at 469:23-471:10 (Griffey Direct) (June 30, 2022).

[327] Tr. at 28:24-29:4 (Viamontes Cross) (June 29, 2022); ETI Ex. 29, Weaver Reb. at 5 (Bates 7 of 71).

For projects where a utility has met its burden to prove that a project will provide net benefits to ratepayers and is necessary for the service to the public, it may be appropriate to implement conditions. Thus the Commission imposed a firm capital cost cap in granting a CCN for the SWEPCO Turk Plant case.[328] In an SPS case, after conducting a supplemental hearing and finding that SPS had shown a probable lowering of costs from two large proposed wind facilities,[329] the Commissioners approved a capital cost cap,[330] a capacity factor guarantee,[331] and a net benefits guarantee.[332]

This case is unlike those cases in which a project has been found to provide expected benefits to ratepayers under reasonable projections. Rather, this case is similar to the ETI Liberty County CCN case[333] and the two SWEPCO Wind CCN cases.[334] In those cases the proper result was a straight rejection of a proposal on which the utility had not carried its burden of proof. That is the proper result in this case as well.

XI. CONCLUSION

The utility carries the burden of proof in a CCN case to show that a proposed facility is necessary and is a prudent alternative. ETI abandoned any attempt to make such a showing, and instead made its prudence case by a comparison to a wildly uneconomic straw man that ETI admits was never intended to identify the best option. For the reasons set forth in the brief, TIEC respectfully requests that ETI's application for a CCN be denied.

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[328] *Application of Southwestern Electric Power Company for a Certificate of Convenience and Necessity for Authorization for Coal Fired Power Plant in Arkansas*, Docket No. 33891, Final Order at 20, Ordering Paragraph 2 (Aug. 12, 2008).

[329] Docket No. 46936, Order at 4 (May 25, 2018).

[330] *Id.* at FoF 68.

[331] *Id.* at FoF 73 .

[332] *Id.* at FoFs 79-81.

[333] TIEC Ex. 8 at CoL 20.

[334] Docket No. 49737, Order at CoL 7 (July 6, 2020); and Docket No. 47461, Order at CoL 10A (Aug. 13, 2018).

Respectfully submitted,

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CERTIFICATE OF SERVICE

I, Benjamin B. Hallmark, Attorney for TIEC, hereby certify that a copy of this document was served on all parties of record in this proceeding on this 18th day of July, 2022 by electronic mail, facsimile, and/or First Class, U.S. Mail, Postage Prepaid.

/s/ Benjamin B. Hallmark
Benjamin B. Hallmark