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APPLICATION OF ENTERGY TEXAS, INC. TO AMEND ITS CERTIFICATE OF CONVENIENCE AND NECESSITY TO CONSTRUCT A PORTFOLIO OF DISPATCHABLE GENERATION RESOURCES	§ § § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ENTERGY TEXAS, INC.'S EXCEPTIONS TO THE PROPOSAL FOR DECISION

PUBLIC REDACTED

JULY 2025

TABLE OF CONTENTS

I. INTRODUCTION ... 1

II. APPLICABLE LAW ... 7

III. PROJECT DESCRIPTION ... 10

A. Legend ... 10

B. Lone Star ... 11

IV. CCN FACTORS ... 11

A. Adequacy of Existing Service and Need for Additional Service ... 11

B. Consideration of Alternatives ... 12

1. ETI's Process for Selecting the Dispatchable Portfolio ... 12

2. Whether a Comprehensive RFP was Necessary or Feasible ... 12

3. Potential Alternatives to the Dispatchable Portfolio ... 19

4. Cost of Dispatchable Portfolio Compared to Similar Technology ... 37

C. Probable Lowering of Cost to Consumers ... 41

D. Other CCN Factors ... 44

E. Administrative Law Judges' Overall Analysis of CCN Factors ... 44

V. PROPOSED CONDITIONS ... 45

A. Cost Cap and Prudence Review ... 45

1. Cost Cap ... 45

2. Prudence Review ... 49

B. Competitive Tariff Proceeding ... 50

C. Hydrogen and Carbon Capture and Storage ... 50

D. Weatherization ... 51

E. Electric Service for Lone Star ... 51

F. Rate-Case Expenses Related to Supplemental Application ... 52

G. Reporting Requirements ... 52

H. TPWD's Recommendations ... 52

VI. PROPOSED GOOD-CAUSE EXCEPTION TO GCRR RULE ... 52

VII. CONCLUSION ... 54

VIII. FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDERING PARAGRAPHS 55

A. PFD's Proposed Findings of Fact, Conclusions of Law, and Ordering Paragraphs ... 55

B. ETI's Proposed Findings of Fact, Conclusions of Law, and Ordering Paragraphs ... 55

TABLE OF ACRONYMS

AACE	Association for the Advancement of Cost Engineering
CCCT	Combined-Cycle Combustion Turbine
CCN	Certificate of Convenience and Necessity
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CT	Combustion Turbine
DPP	Definitive Planning Phase
EIA	Energy Information Administration
ELRAL	Entergy Load Risk Alert Level
EPC	Engineering, Procurement, and Construction
ERAS	Expedited Resource Addition Study
ERCOT	Electric Reliability Council of Texas
ESA	Electric Service Agreements
ESL	Entergy Services, LLC
ETI	Entergy Texas, Inc.
FERC	Federal Energy Regulatory Commission
GCRR	Generation Cost Recovery Rider
LNG	Liquified Natural Gas
MCPS	Montgomery County Power Association
MISO	Midcontinent Independent System Operator, Inc.
MW	Megawatt
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
OCAPS	Orange County Advanced Power Station
PFD	Proposal for Decision
PIE	Power Island Equipment
PPA	Purchase Power Agreement
RFP	Request for Proposal
SPS	Southwestern Public Service Company
SRP	Strategic Resource Plan
SWEPCO	Southwestern Electric Power Company
TIEC	Texas Industrial Energy Consumers
TPWD	Texas Parks and Wildlife Department

CITATION FORM

Citations to ETI testimony and exhibits use the red text labeling at the center of each page of the exhibit.

Citations to Commission Staff and TIEC testimony and exhibits use the Bates numbering at the bottom right of each page.

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ENTERGY TEXAS, INC.'S EXCEPTIONS
TO THE PROPOSAL FOR DECISION

Entergy Texas, Inc. ("ETI" or the "Company") respectfully provides the following exceptions to the Proposal for Decision ("PFD") in this proceeding.

I. INTRODUCTION

ETI's need to deploy the Legend and Lone Star Power Stations (collectively, the "Dispatchable Portfolio") as soon as possible cannot be overstated. **Without these resources, the Company cannot timely serve new customers and will face serious day-to-day reliability challenges in serving *all* customers**. Among others, the Legend Power Station is required to serve facilities in ETI's Eastern Region that are important to the state's economic prosperity and consistent with state and federal policy. These include a [redacted] project at 150 MW, two [redacted] projects totaling over 500 MW, a [redacted] project at 70 MW, seven [redacted] projects totaling over 400 MW, four [redacted] projects totaling nearly 80 MW, an [redacted] project at 20 MW, an [redacted] project for 75 MW, an [redacted] project for 42 MW, and an [redacted] project totaling 140 MW.[1] All told, the new and existing projects that will benefit from the construction of the Legend Power Station include, but are not limited to, LNG facilities, chemicals, and

[1] ETI Ex. 28A Exhibit EP-R-1 (Peeples Rebuttal).

materials manufacturing, and processing facilities.[2] Indeed, just the new industrial loads that have already executed Electric Service Agreements ("ESAs") create a capacity shortfall larger than the capacity of the Legend Power Station.[3] And the Lone Star Power Station is required to reliably serve rapidly growing residential and commercial growth in ETI's Western Region load pocket, including two of the nation's fastest growing counties (Montgomery and Liberty).[4] As discussed below, the Western Region is a load pocket within a load pocket that must already navigate operational challenges to serve customers under normal operating conditions. Notably, no party disputes ETI's critical need for capacity and energy.

ETI is not alone. The Electric Reliability Council of Texas ("ERCOT") predicts it will double its peak load by 2030, and is aggressively seeking to attract new generation.[5] The Governor and Lieutenant Governor have both stressed the critical need for new dispatchable generation in Texas, as has the federal government.[6] U.S. Representative Randy K. Weber, a member of the U.S. House Committee on Energy and Commerce and Representative for the district in which Legend Power Station will be sited, supports approval of the Dispatchable Portfolio in particular as instrumental in ensuring that Texas is positioned to meet demand in a

[2] Note that the potential for LNG projects generally has gained further momentum due to new European Union sanctions where transactions related to Russia's Nord Stream gas pipelines under the Baltic Sea will be banned, including any provision of goods or services to these projects. https://www.reuters.com/sustainability/boards-policy-regulation/whats-eus-18th-sanctions-package-against-russia-2025-07-18/.

[3] As of March 2025, ETI had approximately 900 MW of ESAs executed for incremental load that will take service by mid-2028 compared to Legend's nominal 754 MW capacity. ETI Initial Br. at 10-11, 31.

[4] https://www.texastribune.org/2025/03/13/texas-urban-population-census-2024/

[5] "ERCOT shocked lawmakers last year when it revealed that electricity demand could almost double by 2030. A Dallas senator said at the time that ERCOT's projections signaled the arrival of "a completely new economy really in Texas, and certainly a new grid."
(https://www.houstonchronicle.com/business/energy/article/ercot-texas-power-grid-growth-data-20263609.php.)

[6] ETI Initial Br. at 4-5.

timely manner.[7] Similarly, Texas Representative Dade Phelan, also a Representative for the district in which Legend will be located, supports approval of the Dispatchable Portfolio as necessary infrastructure to support the state's energy demands.[8]

The need to rapidly deploy an enormous amount of dispatchable generation capacity in Texas, the nation, and around the world has significantly impacted the market for and availability of such resources. Accordingly, ETI moved quickly to secure scarce production slots, lock in pricing, and ensure its ability to provide reliable service and enable Texas to capture the remarkable economic growth it is experiencing. By starting the request for proposals ("RFP") for Power Island Equipment ("PIE") when it did, ETI locked in pricing that is ***well below current market prices***. New combined cycle costs are quoted at **$2,400/kW** compared to $1,900/kW for Legend, and there is a tremendous backlog on obtaining new combustion turbines ("CTs") and Combined-Cycle Combustion Turbine ("CCCTs").[9] Absent ETI's quick action to lock in production slots for its customers, the same equipment could not have been obtained and placed in service before 2030, years beyond the critical need date.

Nevertheless, the PFD recommends denial of ETI's application based on the erroneous conclusion that the Dispatchable Portfolio will not result in the probable lowering of costs to customers and elevating that single statutory criterion above all others combined. The PFD reaches the wrong conclusion by failing to appreciate the extraordinary circumstances in which

[7] Docket No. 56693, PUC Interchange Item No. 430.

[8] Docket No. 56693, PUC Interchange Item No. 167.

[9] **"If we wanted to build that same gas-fired combined cycle unit today it would cost $2,400 a kilowatt — the cost of gas-fired generation has gone up more than threefold…. And there are a number of factors that are driving that. One is just supply and demand. There's a lot of demand for gas turbines right now."** (https://www.eenews.net/articles/ceraweek-natural-gas-pitched-as-tonic-for-power-hungry-ai/#:~:text=%E2%80%9CIf%20we%20wanted%20to%20build,for%20gas%20turbines%20right%20now.%E2%80%9D.) **Combined cycle costs are $2400/KW and up to 7 years lead time.** (https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply).

ETI is proposing these resources. As a result, the PFD fails to give appropriate weight to the substantial evidence presented by ETI and the full range of certificate of convenience and necessity ("CCN") criteria, including need and reliability. Importantly, the PFD also misapplies recent decisions from renewable CCN cases in a manner that would hinder the construction of new dispatchable resources that are urgently needed to support existing and new customers in this state.

The PFD focuses almost exclusively on ETI's "consideration of alternatives" as a means of assessing whether the Dispatchable Portfolio will lower costs to customers and then compounds the problem by comparing the proposed resources to *infeasible* alternatives and misapplying prior Commission decisions on the topic. As described in detail below, the Commission recently denied two renewable CCN applications based on a failure to evaluate cost-effective alternatives. But the Commission's rationale was that the utility excluded entire categories of resources, such as *all dispatchable gas resources*, from its analysis. By contrast, the PFD criticizes ETI for excluding two of the many types of gas dispatchable resources from its modeling. And while the PFD acknowledged that purported shortcoming could be overcome, it then gave no meaningful weight to the testimony of ETI's resource and transmission planning experts explaining why those specific resource types were not reasonable alternatives to include in the modeling. Instead, the PFD gives considerable weight to speculation and irrelevant comparisons to resources that cannot address ETI's resource needs. While Preliminary Order Issue No. 31 asks, "are the proposed resources the most cost-effective alternative to meet reliability needs," the PFD appears to focus only on the first part about "the most cost-effective" to the exclusion of the second part about "meet[ing] reliability needs."[10] A resource cannot be

[10] Docket No. 56693, Preliminary Order at 8.

cost-effective if it does not meet the needs of the utility's customers. And the PFD further erred in giving "little weight" to ETI's analysis that *did* compare the Dispatchable Portfolio to standard alternatives that could meet those needs (the three CT scenario);[11] that analysis definitively showed the Dispatchable Portfolio to be a better option—by hundreds of millions of dollars[12]—and thus cost-effective.

Adoption of the PFD would lead to severe consequences. The Southeast Texas region fuels the state, national, and world economies, and is home to the largest concentration of oil refineries and petrochemical plants in the United States, four of the nation's ten largest oil refineries, and the largest methanol facility.[13] The Beaumont-Port Arthur area specifically is a key player in the global energy sector. Three Foreign Trade Zones, several major highways, a regional airport, rail service, and two deep-water ports, as well as proximity to the Port of Houston, connect Beaumont-Port Arthur to global commerce.[14] Major business clusters like chemical and petroleum manufacturing, materials manufacturing, and transportation contribute to the $80 billion in announced and proposed projects in Southeast Texas.[15] As noted above, just the limited set of projects in ETI's Eastern Region that have already signed ESAs create a capacity shortfall larger than the capacity of the Legend Power Station.[16] And that entirely ignores the thousands of MW of additional projects in other stages of development. In addition, portions of ETI's Western Region—home to Montgomery and Liberty counties—are among the

[11] PFD at 74-75.

[12] ETI Ex. 20 at 8 (Nguyen Supplemental Direct).

[13] ETI Ex. 15 at 7 (Peeples Direct).

[14] *Id.*

[15] *Id.*

[16] As of March 2025, ETI had approximately 900 MW of ESAs executed for incremental load that will take service by mid-2028 compared to Legend's nominal 754 MW capacity. ETI Initial Br. at 10-11, 31.

fastest-growing residential and commercial areas in the nation. Given the speed and scale of this growth, combined with the long lead time for deploying new generation resources, ETI must add new incremental, location-specific generation now to keep pace, serve new and existing customers, and maintain reliability. Adding these resources now will also avoid burdening customers with further cost escalation in a market in which demand far outstrips supply.

Without incremental dispatchable generation, ETI will be reliant on the purchase of capacity credits in the Midcontinent Independent System Operator, Inc ("MISO") short-term capacity market to satisfy its capacity obligations in MISO. Not only is the price of MISO capacity credits skyrocketing,[17] those credits do not provide any incremental physical capacity or energy to address the locational reliability needs that ETI must address to reliably and affordably serve new and existing customers.[18] It is therefore critical that ETI construct local generation to not only meet its overall capacity needs, but its reliability needs as well. Without it, ETI will not be able to reliably serve new customers in a timely manner, and much of the industrial load poised to provide economic benefits to the state will not materialize.

Denying ETI's application based on speculative arguments that there might be lower cost alternatives, even though ETI proved those alternatives do not meet its specific locational and operational needs, will simply increase costs, negatively impact reliability, and stall economic expansion in this state. The Dispatchable Portfolio is the lowest *reasonable* cost alternative to

[17] Capacity supplies in MISO are constrained, and MISO's most recent capacity auction results yielded record-high prices for the summer season in the 2025/2026 planning year. See "MISO summer capacity prices jump to $666.50/MW-day as power supplies shrink," Utility Dive (Apr. 29, 2025), available at https://www.utilitydive.com/news/miso-capacity-auction/746576/; Midcontinent Independent System Operator, Planning Resource Auction: Results for Planning Year 2025-26 (presentation) (Apr. 2025), available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf .

[18] PFD at 58.

meet ETI's and Southeast Texas's critical need for reliable, dispatchable power. Accordingly, ETI's application should be approved timely and without condition.

II. APPLICABLE LAW

The PFD correctly cites to the applicable provisions of PURA, particularly PURA §§ 37.056 and 39.452(j). The PFD further acknowledges what the courts and Commission have long held regarding the balancing of factors in certificate of convenience and necessity ("CCN") cases:

> The various factors reflect potentially competing policies and interests whose relative weight will ***vary with the circumstances of each case***. Thus, ***none of the statutory factors is intended to be the absolute*** in the sense that any one shall prevail in all possible circumstances but must instead be balanced to further the overall public interest.[19]

However, the PFD then proceeds to do exactly the opposite by elevating one half of one criterion – cost – above all others combined, in a manner that ignores the extraordinary circumstances at play. With respect to the statutory criteria in PURA § 37.056, the PFD finds:

- (c)(1) – Adequacy of existing service – "ETI is currently providing adequate service to its customers."[20]

- (c)(2) – Need for additional service – "ETI has a need for additional capacity and energy."[21]

- (c)(3) – Effect of CCN on ETI and other utilities serving the proximate area – "the Dispatchable Portfolio would have a positive impact on ETI and its customers in that it would address ETI's need for additional capacity and energy and enhance system reliability" and the intervening utilities serving the proximate area either support or do not take a position on ETI's application.[22]

- (c)(4) – "Other factors":

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[19] PFD at 7, citing *Pub. Util. Comm'n of Tex. v. Textand Elec. Co.*, 701 S.W.2d 261, 267 (Tex. App.–Austin 1985, writ ref'd n.r.e) (emphasis added).

[20] PFD at 134.

[21] *Id.*

[22] *Id.* at 138

- (a) – Community values – "The proposed CCN amendment would not result in adverse effects to community values."[23]
- (b) – Recreational and park areas – "The proposed CCN amendment would not result in adverse effects to recreational and park areas."[24]
- (c) – Historical and aesthetical values – "The proposed CCN amendment would have no adverse effect on historical values and minimal adverse effect on aesthetic values."[25]
- (d) – Environmental integrity – "The Dispatchable Portfolio is expected to have a minimal effect on the environmental integrity of the Project sites."[26]

- (c)(5) – Probable improvement of service or lowering of costs to customers – "The proposed CCN amendment would result in the probable improvement of service" and "enhance reliability"[27] but "[t]he proposed CCN amendment would not result in the probable lowering of cost to consumers in the area."[28]

Thus, despite finding that ETI's CCN application met every one of the statutory CCN criteria apart from one half of one criterion – the probable lowering of costs to customers – the PFD recommends denial of ETI's application. Certainly, ETI recognizes the importance of cost and, as demonstrated by the record evidence and discussed herein, ETI *did* prove that the Dispatchable Portfolio is expected to lower costs to customers compared to *reasonable* alternatives. Indeed, it was ETI's quick action to lock in production slots and pricing that ensured resource availability and prevented further cost escalation. However, even if concerns remain, it is clear the PFD failed to appropriately apply the law by treating one sub-factor (cost) as "absolute" and failed to appropriately consider "competing policies and interests whose relative weight will vary with the circumstances." Here, the circumstances include extraordinary

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[23] *Id.*

[24] *Id.* at 139.

[25] *Id.*

[26] *Id.*

[27] *Id.* at 139.

[28] *Id.* at 140.

load growth, accelerated timeframes for serving that growth, and a severely constrained market for dispatchable generation.

Historically, the Commission determines whether the utility has considered reasonable alternatives to the proposed resource by assessing whether a reasonable resource selection process has occurred.[29] This approach is consistent with regulatory policy that a regulator does not step into the shoes of the resource planner and second guess the results of a reasonable process.[30] But the PFD would usurp the role of resource planning experts and effectively require the utility to establish that proposed resources are the absolute lowest cost alternative regardless of suitability and feasibility.[31] That is not the standard established by the Commission and is inconsistent with the renewable cases cited in the PFD and the Commission's Preliminary Order.[32] The PFD should have evaluated whether the Dispatchable Portfolio is a cost-effective *reasonable* alternative as informed by the reasoned judgment of resource planners with deep knowledge of ETI's system, customers, and needs. As explained below, the purportedly lower-

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[29] *See, e.g.*, Docket No. 52487 at Finding of Fact 80 through 88 and Conclusion of Law 14 (finding that ETI evaluated the performance of five reasonable resource portfolio alternatives, detailing same scenarios, and concluding showing of need); Docket No. 53625, Order on Rehearing at 3 and Findings of Fact 68A (stating "it is the electric utility's burden to demonstrate that its proposed facilities are necessary-including in light of viable alternatives" and finding it was not appropriate to exclude fossil-fuel generation and long-term purchased-power agreements from consideration); Docket No. 55255, Order on Rehearing at 2 and Findings of Fact 70A though 70H (rejecting conclusion that applicant adequately considered alternatives and adding several findings detailing deficiencies in process that excluded consideration of dispatchable resources).

[30] For example, the prudence standard governing the Commission's determination whether a utility's capital investment costs may be passed on to ratepayers requires the Commission not to substitute its judgment for that of the utility. *Pub. Util. Comm'n of Texas v. Texas Indus. Energy Consumers*, 620 S.W.3d 418, 428 (Tex. 2021).

[31] PFD at 2-3, 13, 34, and 78-79.

[32] Preliminary Order issue No. 31. "Would the proposed Legend power station and Lone Star power station improve the reliability of Entergy's service? If so, how would reliability be improved, and are the proposed Legend power station and Lone Star power station the most cost-effective alternative for Entergy *to meet reliability needs*?) (Emphasis added.) *See also* Preliminary Order issue No. 19.c. "If Entergy has demonstrated a need for additional capacity, is each of the proposed Legend power station and Lone Star power station the *appropriate* option to meet that need for additional capacity?" (Emphasis added).

cost alternatives advanced by Texas Industrial Energy Consumers ("TIEC") are not feasible options, so the costs are not relevant.

In addition, although the PFD cites to the correct preponderance of the evidence standard, it fails to properly apply that standard. While the evidence in support of ETI's application is substantial, the Company's burden is not to eliminate all possible doubt and speculation regarding every conceivable resource combination that might result in lower costs even if not feasible, as the PFD would seem to require. Texas law requires the party carrying the burden of proof in civil cases, including Commission proceedings, to prove facts supporting its claim by a preponderance of the evidence,[33] *i.e.*, that the facts supporting its position, are "more likely than not."[34] ETI explains for each issue how the PFD's findings do not comport with the record evidence when the appropriate framework is applied. ETI's evidence outweighs intervenors' speculation on these issues and proposed infeasible alternatives, and the Commission should therefore correct these errors by adjusting the findings of fact ETI lists in Section VIII below and issuing an order finding that ETI's CCN amendment is necessary for the service, accommodation, convenience, or safety of the public.

III. PROJECT DESCRIPTION

A. Legend

No Exceptions.

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[33] *Sw. Pub. Serv. Co., et al. v. Pub. Util. Comm'n of Texas, et al.*, 962 S.W.2d 207, 213 (Tex. App. 1998).

[34] No rule or statute specifically addresses the burden of persuasion in this type of CCN case. However, generally, the party seeking affirmative relief has the burden of persuasion, and the applicant must establish every fact asserted by it that is essential to its right of recovery. *Pace Corp. v. Jackson*, 284 S.W.2d 340 (Tex. 1955); *Application of Rio Grande Electric Cooperative, Inc. to Amend its Certificate of Convenience and Necessity to Include a Proposed Transmission Line within Brewster County*, Docket No. 7437, 14 P.U.C. Bull. 1364, 1369 (Sept. 8, 1988). *See also* 1 Tex. Admin. Code § 155.427.

B. Lone Star

No Exceptions.

IV. CCN FACTORS

A. Adequacy of Existing Service and Need for Additional Service

The PFD acknowledges ETI's undisputed, critical need for capacity, emphasizing that ETI will be short approximately 1,600 MW (winter position) by 2028, reaching nearly 2,400 MW by 2034, only nine years away.[35] The Dispatchable Portfolio would only meet about half of that 2028 need. The PFD also acknowledges that ETI has a separate need for resources in both its Eastern and Western Regions, and that incremental dispatchable capacity is needed for reliability support in those areas.[36] In other words, ETI's ability to keep the lights on could be jeopardized without these resources.[37] The PFD also acknowledges that incremental dispatchable capacity is necessary for ongoing residential and economic expansion.[38] Nevertheless, the PFD inexplicably discounts hundreds of pages of ETI testimony and analyses, disregards the opinions of ETI's resource planning and transmission planning experts who have specialized knowledge of ETI's system and needs, and misapplies recent decisions from renewable CCN cases.

[35] PFD at 15.

[36] PFD at 17 and 58 (discussing benefits of reactive power from Legend and Lone Star, the avoidance of transmission constraints under the Dispatchable Portfolio, and the need for an incremental generation resource located in the Western Region).

[37] *See* ETI Ex. 30 at 17-21 (Kline Rebuttal).

[38] PFD at 20.

B. Consideration of Alternatives

1. ETI's Process for Selecting the Dispatchable Portfolio

ETI has no exceptions to the recitation of facts in this section of the PFD. Below, the Company excepts to aspects of the PFD's analysis of and conclusions about ETI's process for selecting the Dispatchable Portfolio.

2. Whether a Comprehensive RFP was Necessary or Feasible

The PFD properly concludes that ETI's inability to conduct a broader RFP due to circumstances beyond its control is not fatal to its certification request.[39] The PFD rejects Staff's reasoning and comparison to RFPs conducted by two other utilities under different circumstances for brownfield renewable projects as opposed to greenfield dispatchable projects.[40] Nonetheless, the PFD improperly faults ETI for not conducting a broader RFP by discounting ETI's evidence and reasoning that demonstrates the Dispatchable Portfolio is a reasonable cost option to address ETI's resource needs.[41] The PFD sets a *de facto* standard that effectively requires an all-source RFP in all instances based on an overly broad reading and application of two renewable CCN orders.[42] In the referenced Southwestern Electric Power Company ("SWEPCO") and Southwestern Public Service Company ("SPS") cases, the Commission took issue with the

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[39] *Id.* at 33.

[40] *Id.*

[41] *Id.* at 55-59 and 66-68.

[42] *Id.* at 33-34 and 67, citing *Application of Southwestern Public Service Company to Amend its Certificate of Convenience and Necessity to Construct Generation Facilities in Lamb County, Texas and Lea County, New Mexico; for Good Cause Exceptions; and for Related Relief*, Docket No. 55255, Order on Rehearing (Nov. 21, 2024) and *Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization and Related Relief for the Acquisition of Generation Facilities*, Docket No. 53625, Order on Rehearing (Aug. 24, 2023).

utilities' analyses excluding an entire category of alternatives – dispatchable gas resources.[43] That is obviously not a concern here as ETI analyzed a wide range of both dispatchable and renewable resources in its Strategic Resource Plan ("SRP") analysis and is proposing two thermal resources to improve reliability and produce efficient energy. The SWEPCO and SPS orders never suggest that the utility must solicit specific variations of the same type of resource (*e.g.*, to compare monofacial and bifacial solar panels). The Commission should take this opportunity to clarify the scope of those orders so that a utility's reliance on reasoned planning judgment in the design of its analyses is not used as a barrier to deploying much needed dispatchable generation in a timely manner.

As a reminder, leading up to the Application, ETI was very transparent about the rapid change in its resource need and the Company's plans to quickly respond to assure reliable and affordable service. As ETI's Vice President of Business Operations and Strategy, Abigail Weaver recounted in her Rebuttal Testimony, "[t]he Company promptly began informing key stakeholders, including Commissioners, in April 2023 of the need to add dispatchable generation to respond to its capacity deficit and to do so along a faster time frame than had been done in the past with MCPS [Montgomery County Power Station] and OCAPS [Orange County Advanced Power Station] given the expected lead time needed to construct the new generation" – roughly 7 years for a CT and 7.5 years for a 1x1 CCCT, which would have put the in-service dates for these resources in 2030.[44] Given the capacity needs to meet customer growth by 2028, including a large 270 MW load addition that made a firm commitment in early 2023, ETI did not have the

[43] Docket No. 53625, Order on Rehearing at 2-5 and Finding of Fact Nos. 68A, 74 and 78-78I; Docket No. 55255, Order on Rehearing at 3-4 and Finding of Fact Nos. 70F-70H and 72; Docket No. 55255, PFD at 18-20 (Mar. 20, 2024).

[44] ETI Ex. 26 at 4-5 (Weaver Rebuttal).

option to conduct a broader RFP and then complete the regulatory process.[45] The Company had to act quickly to achieve 2028 in-service dates[46] and manage growing operational challenges in its Western Region. Further, ETI is clearly able and willing to conduct a competitive solicitation to test a self-build proposal when feasible and appropriate under the circumstances – as it did so for MCPS and OCAPS.[47] However, for a variety of reasons acknowledged by the PFD, that same process was not feasible here.[48]

A confluence of events required that ETI act swiftly to pursue the Dispatchable Portfolio to add much-needed incremental capacity to its system at specific locations. The passage of the Inflation Reduction Act in August 2022 precipitated interest in the development of industrial projects in ETI's service area to take advantage of favorable tax provisions, causing an appreciable uptick in the number and size of new industrial projects that would eventually result in an increase to the BP24 (developed in mid-2023) load forecast of ~100 MW in 2028. Around the same time, the Federal Energy Regulatory Commission ("FERC") approved resource adequacy construct reforms proposed by MISO that ultimately increased ETI's capacity needs. While ETI was aware that these reforms would affect its capacity position, the full extent of the effects was not known until MISO completed its modeling of the reforms in the first quarter of 2023.[49] On this subject, the PFD wrongly suggests that ETI should have been prescient and foreseen FERC's *sua sponte* issuance of a show cause order in March 2023 directing MISO to

[45] *Id.*

[46] *Id.* at 5-7 and 45 (Weaver Rebuttal); *see also,* ETI Ex. 26A at 31-44 (Weaver Rebuttal).

[47] *See Application of Entergy Texas, Inc. to Amend its Certificate of Convenience and Necessity to Construct Orange County Advanced Power Station*, Docket No. 52487, Order on Rehearing at Finding of Fact Nos. 89-90 (Jan. 12, 2023) and *Application of Entergy Texas, Inc. to Amend Its Certificate of Convenience and Necessity to Construct Montgomery County Power Station in Montgomery County,* Docket No. 46416, Order at Finding of Fact No. 5 (July 28, 2017).

[48] PFD at 33-34.

[49] ETI Ex. 26 at 5-7 and 45 (Weaver Rebuttal).

recalculate its planning resource needs to support the Planning Resource Auction well after the changes to MISO's resource adequacy construct had been previously accepted by FERC.[50]

The PFD also erroneously suggests that ETI's timing constraint was due in part to a failure to account for its own unit deactivations.[51] That commentary cannot be squared with the evidence. Unit deactivations are continuously monitored and identified in each annual supply plan and in the SRP.[52] That statement is also inconsistent with the PFD's finding that extending the lives of existing resources would not adequately address ETI's resource need.[53] Unit deactivations are simply not an issue in this case.

Returning to unforeseeable events, in late 2022, the counterparty to a long-term 225 MW power purchase agreement ("PPA") notified ETI of potential cancellation of the PPA. In early 2023, the counterparty terminated the 225 MW PPA, while at the same time a large customer made a firm commitment to add 270 MW of load that will come online in 2027.[54]

After considering all these factors, ETI decided to take the steps necessary to preserve the option to deploy the Dispatchable Portfolio because it was apparent that dispatchable generation would be required to address ETI's location-specific need for additional capacity and energy in both its Eastern and Western Regions. In the Eastern Region, several industrial customers "firmed up" their plans to build new large facilities in the Port Arthur area. In the Western Region, the Company observed continued growth in residential customer counts and a series of demand records that necessitated prolonged periods of conservative operations to address

[50] *Midcontinent Indep. Sys. Operator, Inc.*, 182 FERC ¶ 61,176, Order Establishing a Show Cause Proceeding (Mar. 17, 2023); and 183 FERC ¶ 61,022, Order Terminating Show Cause Proceeding (Apr. 17, 2023).

[51] PFD at 34.

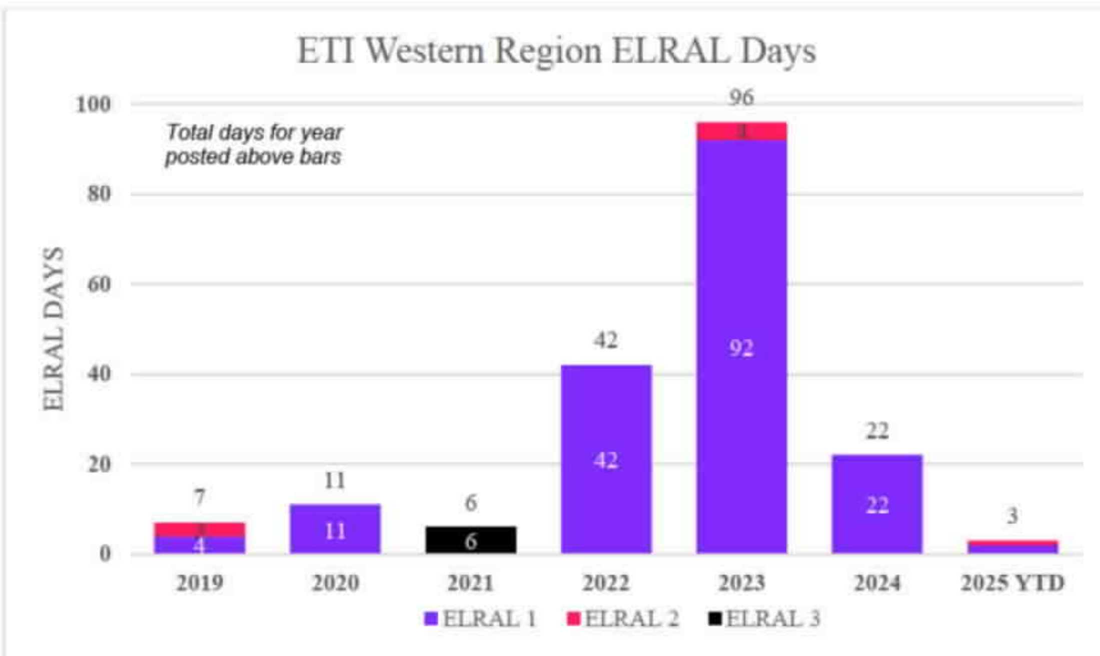
[52] ETI Ex. 4A at 77 and 140 (Weaver Direct); ETI Ex. 9 at 57 (Boratko Direct).

[53] PFD at 60.

[54] ETI Ex. 26 at 6 (Weaver Rebuttal).

elevated risk, as shown in Figure 1 below, and which are continuing today.[55] In 2023 in particular, the Western Region operated at ELRAL 1 (two contingencies) for three summer months and ELRAL 2 (one contingency) for four days.[56] More recently, in 2024, the Western Region operated at ELRAL 1 for 22 days, and in the first quarter of 2025, the Western Region operated at ELRAL 1 for two days and ELRAL 2 for one day.[57] Notably, these elevated levels of risk occurred not during an outage, a storm event or other system constraint, but during expected system conditions with all generation assets available and all transmission lines in service.[58]

<u>Figure 1</u>
Western Region ELRALs



[55] ETI witness Mr. Kline explains Entergy Load Risk Alert Level ("ELRAL") designations in response to Q27 in his direct testimony. ETI Ex. 5 at 24-25 (Kline Direct); ETI Ex. 30 at 25 (Kline Rebuttal); ETI Ex. 26 at 15-16 (Weaver Rebuttal).

[56] *See* ETI Ex. 5 at 33 (Kline Direct).

[57] *See* ETI Ex. 30 at 25 (Kline Direct); ETI Ex 26 at 15-16 (Weaver Rebuttal). Rebuttal testimony was filed on March 24, 2025, and does not reflect additional ELRAL conditions that occurred after that date.

[58] ETI Ex. 5 at 33-34 (Kline Direct); ETI Ex. 4 at 20-21 (Weaver Direct).

ETI began developing a CCCT as a baseload resource to address the around-the-clock needs of the industrial expansions taking place in the Eastern Region and began developing a CT as a peaking resource to address the peaking load profile of the residential and commercial growth taking place in the Western Region.[59] At the same time, and as discussed below, ETI used the new SRP process to test whether an optimized portfolio would include dispatchable generation, and to what extent. The SRP preliminary results supported the conclusion that two dispatchable generation resources should be deployed in the near term. Based on those preliminary results, ETI decided to proceed with the PIE RFP pending the final SRP results,[60] again, to preserve optionality. Here, the PFD criticizes ETI, suggesting that the Company's resource planning actions should have been rigidly sequential and linear in nature.[61] However, the PFD fails to appreciate that, to preserve options, resource planning requires some level of flexibility for the utility to react to circumstances as they develop and change. Under the circumstances facing ETI, it was necessary to exercise professional judgment to identify resources capable of addressing ETI's impending resource needs in the Eastern and Western Regions, develop and use the SRP modeling to test and confirm the selection of resources, and move ahead with development of the PIE RFP based on information obtained from both those exercises. The fact that ETI performed these resource planning exercises in parallel to preserve the feasibility and timing of a known option simply reflects the agile resource planning required to operate in the present environment of rapid economic expansion amidst limited supply. It is no basis to question ETI's planning and analysis.

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[59] ETI Ex. 4 at 21 (Weaver Direct).

[60] *Id.* at 22.

[61] PFD at 55-56 and 67.

Perhaps most critically, with respect to the timing and speed of ETI's decision-making for moving forward with development of the Legend and Lone Star projects in lieu of a broader RFP, the uncontroverted evidence shows that, given the time required to develop and construct these types of generation resources, it is highly unlikely that any alternative resources could have been designed and constructed to be in service in time to meet ETI's pressing capacity needs starting in 2028.[62] Had ETI not acted as quickly and as decisively as it did in 2023 with implementation of the PIE RFP and, instead, used precious time to develop and administer an "all-source" RFP, any new resources selected out of such a solicitation would likely not have been in service until 2030 at the earliest.[63] The extreme and unprecedented increase in demand for turbines and other major equipment used in the construction of the Dispatchable Portfolio has outpaced supply, leading to rapid and exponential cost increases over the last two years. Labor costs have also risen much higher and much faster than previously expected. Simply procuring the necessary equipment and labor for projects of the magnitude of the Dispatchable Portfolio has now become extremely difficult.[64] And given the highly constrained turbine market and worldwide demand for the major equipment required to construct CCCT and CT projects, any project developer bidding into a hypothetical "all-source" RFP would have faced the same price pressures that applied to ETI's solicitation for bids for the power island equipment for Legend and Lone Star.[65] Ultimately, any delay on ETI's part in 2023 could have put the Company in the same predicament as several of the project developers who initially applied for loans from the TEF but have since been forced to withdraw from the program due, at least in part, to the

[62] ETI Ex. 27 at 12 (Ruiz Rebuttal).

[63] *Id.*

[64] *Id.* at 5.

[65] *Id.* at 13.

inability to procure the required equipment to construct their natural-gas fired simple-cycle and combined-cycle generating facilities.[66] All of these factors strongly support ETI's reasonable and prudent decisions to implement the PIE RFP and obtain competitive bids for the major equipment for the Dispatchable Portfolio.

3. Potential Alternatives to the Dispatchable Portfolio

J- vs. F-Class CTs

The Commission should reject the PFD's conclusion that two F-class CTs should have been analyzed as alternatives to the J-Class CT. While the PFD concludes that ETI is correct to be mindful that its long-lived generation investment does not become a stranded investment due to evolving environmental regulations,[67] it then confusingly ignores all the evidence (historical and forecasted modeling data) that doing so favors a J-Class CT over two less efficient, older technology F-Class CTs. Instead, as discussed below, the PFD relies on a generic statement regarding the typical operating characteristics of a peaking unit.[68]

The F-Class CT is an older, less-efficient technology with a higher emissions rate than a J-Class CT. This is important because ETI's production cost modeling shows the Lone Star CT operating at or above an annual capacity factor of 20% to support system stability. Current emissions rules, which are based on the latest turbine technology (*e.g.*, the J-Class), restrict emissions to 1,170 lb. CO_2/ MWh-gross for units operating > = 20% capacity factor. At this expected capacity factor, F-Class CT emissions are higher than that limit. In contrast, Lone Star operating as a J-Class CT with a > = 20% capacity factor is expected to have emissions below

[66] https://interchange.puc.texas.gov/Documents/56896_63_1457201.PDF (Withdrawal letter from Howard Energy Partners); https://interchange.puc.texas.gov/Document/56896_66_1469520.PDF (Withdrawal letter from ENGIE Flexible Generation NA LLC).

[67] PFD at 56.

[68] *Id.*

1,100 lb. CO_2/MWh-gross. See Table 1 (HSPM) below derived from the 2025 Business Plan resource modeling.[69]

<u>Table 1</u> (HSPM)

[redacted]

ETI's production cost modeling also projects that, in most years, Lone Star will continue to operate at a > 20% capacity factor even after the SETEX transmission project is put in place to help shore up Western Region reliability, as shown in Table 2 (HSPM) below.[70]

[69] ETI Ex. 33A at 6-7 (Boratko Rebuttal).

[70] ETI Ex. 33A at 8-9 (Boratko Rebuttal) and WP_Q6_Q7_Lonestar_CT_CO2_Rate_HSPM.

<u>Table 2</u> (HSPM)

[redacted]

These modeling results are further supported by the historical operating experience of the Lewis Creek units located in the Western Region. These units are less efficient steam turbines that MISO currently calls on for transmission system support, and they have operated at annual capacity factors exceeding 20% in each of the last 10 years, as shown in Table 3 below.[71]

[71] Tr. at 95:20-97:22 (Boratko Redirect) (Apr. 9, 2025); ETI Ex. 42 at 5 (the Lewis Creek units are denoted as LEC1 and LEC2).

Table 3
Lewis Creek Capacity Factor

	Lewis Creek 1	Lewis Creek 2
2015	53.68%	49.47%
2016	45.3%	60.69%
2017	33.49%	44.4%
2018	45.4%	43.8%
2019	47.36%	51.26%
2020	55.07%	48.34%
2021	34.45%	24.08%
2022	35.93%	46.58%
2023	37.87%	42.46%
2024	48.5%	52.23%

In other words, all the unrebutted evidence in the case says the new resource located in the Western Region will need to consistently operate at a capacity factor that is inconsistent with F-Frame technology emissions. The PFD's analysis completely overlooks this empirical data,[72] which is an error. Further, the fact that this information was discerned and presented post-modeling does not diminish its value or weight.[73] It is still true, validates the pre-modeling professional judgement exhibited by ETI resource planners, and proves that F-Class CTs are not viable resources in this particular instance.

The PFD defaults to the position that ETI should have performed additional production cost modeling that included F-Class CTs to prove that the J-Class CT is more cost effective than two F-Class CTs. Again, cost is not the sole determination and is only relevant if one is

[72] PFD at 56.

[73] *E.g., Gulf States Utilities Co. v. Pub. Util. Comm'n of Texas*, 841 S.W.2d 459, 476 (Tex. App. 1992), *writ denied* (Sept. 10, 1993)(… "prudent decision-making may be demonstrated in one of two ways: '[T]o recover costs in rates, a utility may show either that its decision making process was prudent, or that the same decision is in the select range of options that would have resulted had prudent decision making been employed.'" "When there is no evidence of contemporaneous investigation and analysis, a utility may employ the second method, analyzing the prudence of the decision after-the-fact."). While not directly on point, this precedent supports evaluation of contemporaneous documentation on a post-modeling basis.

comparing feasible alternatives. Reliability requirements indicate the Western Region needs a peaking unit that is able to reliably and consistently operate above a 20% capacity factor. The SRP modeling included CT capacity, and once selected, that CT capacity was called on to operate at or above a 20% capacity factor to support transmission system stability in production cost modeling assessments.[74] At the same time, in the modeling, the Lewis Creek units are projected to operate at a lower capacity factor after the CT is added because they are less efficient than the CT.[75] In other words, the production cost model calls on the more efficient capacity – the new CT – to satisfy the transmission reliability requirements.[76] It is logical to expect the same results if the model had used an F-Class CT because it too is expected to be more efficient than Lewis Creek, which is older steam turbine generating technology.[77] Thus, be it J-Class or F-Class, the SRP modeling calls for new CT capacity, and the production cost modeling called for that capacity to be dispatched to operate at a ≥ 20% capacity factor. Under these circumstances, it follows that the F-Class CT is not a viable long-term solution because it cannot operate at or above a 20% capacity factor and still maintain compliance with current emissions standards.[78]

In sum, investing in F-Class CTs for Lone Star would not address Western Region reliability requirements to the same extent as the J-Class CT, because the operations of those F-Class CTs would be limited to less than a 20% capacity factor, requiring the Company to incur

[74] ETI Ex. 33A at 6-9 (Boratko Rebuttal); Tr. at 68:21-69:4, 85:13-19; 96:20-97:4 (Boratko Cross and Redirect) (Apr. 9, 2025).

[75] TIEC Ex. 40 at 006 (both Lewis Creek #1 and #2 projected capacity factors drop below 20% in 2029 after Lone Star is in service); Tr. at 76:24-77:23 and 80:5-15 (Boratko Cross) (Apr. 9, 2025).

[76] Tr. at 79:2-78:15 (Boratko Cross) (Apr. 9, 2025).

[77] Tr. at 79:2-80:23, 85:15-19, 86:19-87:14, 96:9-97:4 (Boratko Cross and Redirect) (Apr. 9, 2025).

[78] ETI Ex. 33 at 6-9 (Boratko Rebuttal).

additional costs to be able to fully address its reliability requirements. In contrast, the J-Class CT emission profile means that ETI can operate the J-Class peaking unit in excess of a 20% capacity factor to support system stability and respond to varying system conditions (*e.g.*, severe weather, load swings, or generation/transmission outages) while still complying with current emissions rules.[79] It was therefore reasonable for ETI to pursue the J-Class CT technology in order to meet the specific needs of its system, and best meet its customers' needs over the long life of this major investment.

The PFD points to the deployment of F-Class CTs by other utilities to imply the F-Class may be a viable solution.[80] However, there is no record evidence that the utilities developing these F-Class CT projects would need to run them at capacity factors at or above 20%, as is the case for ETI. Moreover, the PFD's specific reference to the Hallsville CTs proposed by SWEPCO to be built on SWEPCO property at the site of a retired lignite plant as a "cost-effective" example ignores a critical timing difference of the in-service dates of Legend and Lone Star as compared to these CT units (as well as the costs associated with development of a greenfield versus a brownfield site).[81] Market escalation has accelerated radically in the last few years, and the market for equipment and labor remains volatile and likely subject to further escalation. SWEPCO's units appear to be scheduled for commercial operation in 2027,[82] so the landscape of the market when they were being developed was materially different and likely less expensive than what Lone Star faced. In addition, the SWEPCO estimate is based on an

[79] ETI Ex. 33 at 7 (Boratko Rebuttal).

[80] PFD at 57.

[81] PFD at 57 n.225.

[82] ETI Ex. 27 at 9 (Ruiz Rebuttal).

Association for the Advancement of Cost Engineering ("AACE") International[83] Class IV cost estimate provided by Burns & McDonnell that was prepared using historical reference project data from projects completed in 2023, then "adjusted to reflect current market conditions, commodities."[84] This estimating approach has a much lower accuracy range than the open book process ETI conducted for Lone Star, which had an accuracy range of -10 to +15%.[85] Moreover, the estimated engineering, procurement, and construction ("EPC") costs for Lone Star became much more certain following execution of the EPC contract in April 2025, meaning they now have a high degree of accuracy.[86] The values presented by SWEPCO as an AACE Class IV, on the other hand, have an accuracy range of -30% to +50%.[87] For all these reasons, the PFD's reference to these SWEPCO units as a cost-effective alternative is invalid and has no bearing on the reasonableness of the cost estimates for Lone Star.

The PFD's view that an F-Class turbine might be a feasible alternative appears to rest on a single statement made by ETI witness Sean McHone, a consultant with Sargent & Lundy, who offered testimony that Lone Star is a "low load CT unit," or peaking unit, and that low load CT units are typically characterized as operating at less than a 20% capacity factor. The PFD places great weight on the fact that Mr. McHone said he relied on Mr. Ruiz, who oversees the teams constructing Legend and Lone Star, for the proposition that ETI plans to operate Lone Star as a peaking unit.[88] ETI does not dispute that the Lone Star CT is classified as a peaking unit or that

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[83] The Association for the Advancement of Cost Engineering International cost estimate classification system is the standard for cost estimates in the power plant construction industry. ETI Ex. 7 at 6-7 (Ruiz Rebuttal).

[84] ETI Ex. 27 at 9 (Ruiz Rebuttal).

[85] *Id.* at 5, 9.

[86] *Id.*

[87] *Id.* at 8-9.

[88] PFD at 56.

peaking units *typically* operate at capacity factors below 20%. However, Mr. McHone was not addressing the specific Western Region transmission reliability guidelines that are incorporated into ETI's production cost modeling.[89] That analysis, which is more specific than generic operating profiles for generation types discussed by Mr. McHone, shows that Lone Star is expected operate above a 20% capacity factor, which is the critical issue here.

The PFD's inaccurate reliance on Mr. McHone's testimony fails to account for three key facts: 1) Lewis Creek is still being called on to support Western Region reliability and operating well above a 20% capacity factor;[90] 2) reliability requirements cause the production cost modeling to project that the incremental CT capacity will do the same;[91] and 3) the production cost modeling for CTs like Lone Star is conservative because it does not capture real time events that can cause quick-start CT capacity to be called on for energy and system support.[92] Thus, regardless of whether Lone Star is characterized as a "low load CT" or "peaking unit," which it will be relative to other resources such as MCPS, OCAPS, and Legend, this unit will operate at a capacity factor that is too high for ETI to rely on F-Frame CTs in a simple-cycle configuration.

Finally, resource planning requires the balancing of many factors in determining how best to meet customers' needs. The PFD's suggestion that two F-Class CTs might provide a resiliency benefit over one larger J-Class CT does not overcome long-term viability, reliability and efficiency considerations.[93] Moreover, ETI's point about reducing single point of failure as

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[89] Nor was Mr. McHone suggesting in any way that Lone Star would be *required* to operate at less than a 20% capacity factor; his testimony is thus akin to dicta in a court's opinion—and the PFD erred in extrapolating from it more than what it was offered for.

[90] ETI Ex. 42 at 5; Tr. at 95:20-97:12 (Boratko Redirect).

[91] ETI Ex. 33A at 6-7 (Boratko Rebuttal).

[92] Tr. at 87:15-21 and 94:12-24 (Boratko Cross and Redirect) (Apr. 9, 2025).

[93] PFD at 57.

a resiliency benefit is due, in part, to spacing the resources apart geographically.[94] The purported F-Class alternative would place two F-Class CTs at the same location, which diminishes that resiliency benefit.

The Western Region is a vital component of Texas's growing economy. It is where many people are moving to reside in this state and support the businesses that call Houston and surrounding communities home.[95] The load growth in the Western Region is fast-paced, moving at nearly twice the national average.[96] This significant and rapid load growth has challenged ETI's ability to continue to provide reliable service within the Western Region.[97] Based on its past operating experience serving a Region that is a load pocket within a larger load pocket (an undisputed fact), the level of projected growth within that load pocket, and the critical need for voltage support and load serving capability in the Western Region,[98] ETI proposes to locate a modern, efficient CT resource close to the growing load. This proposal is intended to work in concert with planned transmission reliability projects to assure reliable service in the Western Region going forward.[99]

Lone Star is suited to address the Company's unique system requirements, and it should not be rejected simply on the basis that other utilities with different system requirements and in-service dates are currently able to make use of older, less efficient F-Class technology to meet their own unique needs. ETI is not suggesting it will never consider deploying an F-Class CT

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[94] *E.g.*, ETI Ex. 26 at 19-20 (Weaver Rebuttal).

[95] ETI Ex. 4 at 13-14 (Weaver Direct); ETI Ex. 26 at 11-16 (Weaver Rebuttal).

[96] *Id.*

[97] *Id.*

[98] *Id.*; ETI Ex. 5 at 7-10 and 32-43 (Kline Direct).

[99] ETI Ex. 26 at 22 (Weaver Rebuttal); ETI Ex. 30 at 16-21 (Kline Rebuttal); TIEC Ex. 69 at 1 and 25 (TIEC 17-2).

resource in the future. That technology is simply not the best option to address Western Region needs under the circumstances.

2x1 CCCT

The PFD's conclusion that ETI failed to consider alternative generation technologies rests on a theory that such alternatives are only "considered" if they are included in capacity expansion and production cost modeling.[100] Under that theory, resource planning is reduced to uninformed ("garbage in, garbage out") modeling and lacks the critical benefit of resource planning judgement, institutional knowledge of system topology and operating characteristics, as well as past operating experience. Just because a resource technology was not modeled does not mean it was not considered or that the modeling or overall resource planning process is lacking. Here, no party disputes that ETI *considered* 2x1 CCCT technology as a potential resource to meet its needs. The dispute is over whether that resource should have been modeled.[101] Sound and valid reasons support the decision to exclude the 2x1 CCCT from the SRP modeling.[102]

Entergy Services, LLC ("ESL") maintains a Generation Technology Assessment that identifies a range of potential viable supply-side resource alternatives that merit more detailed analysis due to their potential to meet the planning objectives of the Entergy Operating Companies. ETI used the Generation Technology Assessment to conduct an evaluation of the cost-effectiveness and feasibility of deployment for more than 30 potential supply-side resources. Each version of the Generation Technology Assessment presented in this proceeding included a

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[100] PFD at 55-59 and 66-68.

[101] TIEC Ex. 1 at 022-025 (Griffey Direct); PFD at 57-58 and 67.

[102] ETI Ex. 9 at 12-13 (Boratko Direct); ETI Ex. 30A at 5-6 (Kline Rebuttal); ETI Ex. 28 at 19-21 (Weaver Rebuttal); TIEC Ex. 1A at 213-220 (Griffey HSPM CSG-2); TIEC Ex. 43 (TIEC 2-1); TIEC Ex. 44 (TIEC 4-6); TIEC Ex. 45 (TIEC 17-1).

2x1 CCCT.[103] The supply-side resources selected by ETI for inclusion in the resource planning models were those deemed to be the most feasible to serve ETI's generation needs based on comparative levelized cost of energy and performance parameters, deployment risks (cost/schedule certainty), and emerging commercial, technical, and policy considerations. The evidence shows that ETI selected a broad range of thermal, dispatchable resources and renewable resources for the SRP modeling.[104]

Contrary to the PFD's conclusion that a 2x1 CCCT was not evaluated,[105] ETI actively considered at the outset the viability of a 2x1 CCCT solution and then deliberately excluded that configuration from the optimization modeling. There were several valid reasons for doing so. First, and as acknowledged by the PFD, ETI's locational reliability requirements necessitate that incremental conventional generation be located in ***both its Eastern and Western Regions***.[106] Clearly, a single 2x1 CCCT configuration cannot satisfy the needs in ***both*** regions, a fact acknowledged by the PFD.[107]

Second, ETI is undertaking initiatives to enhance the resiliency of its electric system to mitigate against storm risk and other extreme weather events. A 1x1 configuration is consistent with that initiative because, all else equal, deployment of multiple, smaller units at geographically diverse locations reduces the single point of failure risk, whether that risk be due

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[103] TIEC Ex. 1A at 101, 128, 132, 163 and 167 (Griffey Direct, Exhibit CSG-2).

[104] ETI Ex. 9 at 10-11 (Boratko Direct).

[105] PFD at 57-58 and 66-68.

[106] PFD at 57-59 and 67; ETI Ex. 9 at 12-13 (Boratko Direct); ETI Ex. 5 at 7-10, 13, 32-42 (Kline Direct).

[107] PFD at 58-59; ETI Ex. 9 at 12-13 (Boratko Direct); ETI Ex. 5 at 7-10, 13, 32-42 (Kline Direct).

to extreme weather conditions or a random forced outage.[108] That approach also affords more flexibility in taking planned maintenance outages for generation and transmission.[109]

Third, ETI's generation portfolio will soon include over 2,100 MW sourced from two modern, cornerstone 2x1 CCCTs – MCPS (already in service) and OCAPS (scheduled to be placed in service in 2026). Having those two large facilities in place provides ETI with the necessary flexibility to diversify its generation portfolio with smaller conventional generation resources to achieve resiliency and operational benefits.[110]

The PFD's reasoning fails to recognize that the SRP capacity expansion modeling does not "identify the locations of the resources based on the needs of ETI's service territory, including voltage requirements" or "consider transmission constraints."[111] These SRP modeling limitations were not disputed by any party. As acknowledged by the PFD, the Western Region is its own load pocket that will require incremental voltage support to maintain reliability as load grows.[112] That need is best addressed by locating incremental generation near the growing load in the Western Region.[113] The PFD concurs.[114] ETI understood these transmission-related reliability considerations when it developed the SRP modeling framework. It is for this reason and the others noted above that ETI's resource planning team exercised its professional judgment to exclude a 2x1 CCCT from the modeling at the outset so that the model would optimize the identification of feasible dispatchable resources that ETI could then locate in each of its

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[108] *E.g.*, ETI Ex. 26 at 19-20 (Weaver Rebuttal).

[109] ETI Ex. 9 at 12-13 (Boratko Direct); ETI Ex. 5 at 7-10, 13, 32-42 (Kline Direct).

[110] *Id.*

[111] ETI Ex. 9 at 6 (Boratko Direct); *see also* Tr. at 179:21-180:5 (Boratko Cross) (Apr. 8, 2025).

[112] PFD at 58; ETI Ex. 5 at 24-25 and 32-42 (Kline Direct); ETI Ex. 26A at 15-16 (Weaver Rebuttal).

[113] ETI Ex. 5 at 7-10 and 32-43 (Kline Direct); ETI Ex. 30 at 16-27 (Kline Rebuttal).

[114] PFD at 58.

transmission-constrained Regions.[115] The SRP modeling selected the combination of a CT and CCCT as the next incremental dispatchable generation in optimized portfolios in four of the five scenarios modeled. Recognizing that sound resource planning does not focus on a single potential future scenario, ETI determined that the combination of a CT and a CCCT is the best course of action to meet customers' needs across a broad range of planning futures.[116] ETI then again exercised reasonable resource planning judgment to locate the CT in the Western Region and the CCCT in the Eastern Region to align with the load profiles and transmission constraints of the respective Regions.[117]

Had ETI not exercised resource planning judgment on the front end in developing the framework of the SRP modeling to exclude the larger 2x1 CCCT from this iteration of the modeling, the Company would have done so on the back end. In other words, had a 2x1 CCCT been included in the modeling and selected in lieu of two smaller resources, ETI would have recognized that the modeling did not account for transmission constraints or incremental voltage support needs. Based on those factors, ETI would have exercised the same resource planning judgment to select two dispatchable resources so that one could be deployed in each transmission-constrained Region.[118] The result would be the same regardless of whether ETI exercised its resource planning judgment on the front end or back end of the modeling.[119] To be clear, none of this is to say that ETI will not consider 2x1 CCCT resources going forward. It is

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[115] ETI Ex. 9 at 12-13 (Boratko Direct); Tr. at 156:11-157:24 (Weaver Cross) and 183:17-19, 207:6-11, 208:17-209:13 (Boratko Cross and Redirect) (Apr. 8, 2025); Tr. at 48:8-20 (Weaver Redirect) (Apr. 9, 2025).

[116] ETI Ex. 4 at 18-19 (Weaver Direct); ETI Ex. 9 at 30-31 and 121-122 (Boratko Direct).

[117] ETI Ex. 4A at 92-124 (Weaver Direct).

[118] Tr. at 156:22-157:24 (Weaver Cross) (Apr. 8, 2025); Tr. at 208:17-209:13 (Boratko Redirect) (Apr. 8, 2025).

[119] *Id.*

simply that, at this juncture, ETI is faced with fast-paced load growth in both the Eastern and Western Regions and already has two cornerstone 2x1 CCCT units providing a significant contribution to the Company's capacity position.[120] It is a well-established resource planning tenet that, from a reliability perspective, placing generation near load is preferable to transmission-only solutions.[121] The PFD concurred,[122] and no party disputes the load growth in the Western Region or that the SRP modeling does not take into account the transmission constraints faced in that Region. Given these considerations, it is nonsensical to conclude that ETI should have nevertheless modeled a non-viable single 2x1 CCCT solution simply for the sake of assessing cost effectiveness.[123] A resource cannot be "cost-effective" if it is not a viable means of meeting a need.

Where an incremental resource is needed in the Western Region, the only viable solution that includes a 2x1 CCCT is to site a 2x1 CCCT in the Eastern Region *plus* CT capacity in the Western Region. No additional modeling is needed to understand that a 2x1 CCCT plus a CT would cost significantly more than a 1x1 CCCT plus a CT (*i.e.*, the Dispatchable Portfolio).

Transmission upgrades are also a key consideration in this cost comparison. ESL studied the transmission system impacts of locating additional 2x1 CCCT resources in load pockets on the Entergy transmission system and determined that doing so would require transmission upgrades to maintain compliance with North American Electric Reliability Corporation ("NERC") reliability requirements.[124] ESL also ran a study to determine the transmission

[120] ETI Ex. 4 at 13-14 (Weaver Direct); ETI Ex. 10 at 19-20 (John Direct); ETI Ex. 15 at 14-15 (Peeples Direct); ETI Ex. 26 at 11-15 (Weaver Rebuttal); ETI Ex. 28A at 12 (Peeples Rebuttal).

[121] ETI Ex. 5 at 7-9 (Kline Direct).

[122] PFD at 58.

[123] *Id.* at 57.

[124] TIEC Ex. 1A at 213-220 (HSPM Griffey Exhibit CSG-2).

upgrades necessary to obtain generation interconnection service from MISO for a 2x1 CCCT located at the Legend site instead of the Dispatchable Portfolio.[125] ETI determined that a 2x1 CCCT located at the Legend site would result in $790 million in required transmission upgrades.[126] In contrast, a study run under the same parameters determined that no transmission upgrades are needed to obtain generation interconnection service for either Legend or Lone Star.[127]

At the same time, the uncontroverted evidence is that the 2x1 CCCT generic project cost estimate has increased substantially. Using more current cost estimates, the project cost for a 2x1 CCCT, inclusive of transmission upgrades but excluding site-specific costs like soil remediation, would exceed [redacted] billion.[128] Even if one were to assume lower cost CT capacity in the Western region, an assumption ETI disputes for the reasons discussed below, doing so would not change the conclusion that the Dispatchable Portfolio is a lower cost option than including a 2x1 CCCT plus transmission upgrades in the solution. Again, no additional capacity expansion modeling is needed to arrive at that conclusion.

Importantly, this total project cost comparison cannot be diminished by the PFD's conjecture that some transmission upgrade costs associated with a 2x1 CCCT might be deferred or allocated to other projects.[129] That conjecture is at complete odds with the evidence that 1) the MISO Definitive Planning Phase ("DPP") process has become protracted and, for that reason; 2) ETI will need to use a more expedited process to secure interconnection service to

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[125] TIEC Ex. 44 (TIEC 4-6).

[126] *Id.*

[127] *Id.;* ETI Ex. 30 at 5-14 (Kline Rebuttal).

[128] ETI Ex. 30 at 6-7 (Kline Rebuttal); *see also*, ETI Ex. 33A at 6, 11-28 (Boratko Rebuttal); ETI Ex. 26A at 21 (Weaver Rebuttal).

[129] PFD at 58.

meet a 2028 in-service date for Legend given the need to address swift load growth in the Eastern Region.[130] MISO refers to that new expedited service as Expedited Resource Addition Study ("ERAS").[131] As explained by ETI witness Mr. Kline, his team performed an analysis commensurate with what MISO would use in its new ERAS process, and that analysis showed that addition of a new 2x1 CCCT will require transmission upgrades of approximately $790 million because a new 2x1 in the Eastern Region would trigger NERC reliability thresholds as a new single largest contingency.[132] Importantly, through the new ERAS process, all identified transmission upgrades are assigned to the resource requesting interconnection – there is no opportunity to defer identified upgrades or allocate costs among projects in the DPP interconnection queue. This is made abundantly clear in MISO's recent ERAS filing approved by FERC.[133] These incremental 2x1 CCCT transmission upgrade costs cannot be overlooked or assumed away, and the fact that they are supported by objective analysis far outweighs any conjecture that some of those costs might be deferred or allocated through the MISO DPP that ETI does not plan to use. The PFD's findings to the contrary are inconsistent with the record evidence and MISO's ERAS process.

In sum, the 2x1 CCCT cost comparison is a red herring because 1) it is not a viable solution in lieu of the Dispatchable Portfolio; and 2) no additional modeling is needed to

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[130] ETI Ex. 5 at 54-55 (Kline Direct); ETI Ex. 30 at 27-28 (Kline Rebuttal).

[131] ETI Ex. 30 at 27 (Kline Rebuttal).

[132] *See* TIEC Ex. 43 (TIEC 2-1); TIEC Ex. 44 (TIEC 4-6); TIEC Ex. 45 (TIEC 17-1); ETI Ex. 26A at 21 (Weaver Rebuttal).

[133] *Midcontinent Indep. Sys. Operator, Inc. Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Expedited Resource Addition Study Filing*, Docket No. ER25-2296-000, Section 205 Transmittal Letter at 4, 7-8, 11, 36, 38 and 46 (June 6, 2025) (an ERAS request includes a full commitment to pay for all the costs of identified Network Upgrades and insulates projects in the DPP queue from cost shifts from ERAS projects). On July 21, 2025, FERC formally approved MISO's ERAS Process. *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

conclude that crafting a solution that includes a 2x1 CCCT for the Eastern Region plus CT capacity for the Western Region is a far more expensive proposition than the Dispatchable Portfolio.

Existing Resources

The PFD's analysis of ETI's consideration of existing resources is also at odds with the record evidence and other findings.[134] The PFD concludes ETI has a need for incremental capacity in the Western Region and that existing resources may be able address that need. [redacted][135] Thus, [redacted] cannot "obviate or delay the need for Lone Star."[136]

The PFD also incorrectly concludes that ETI did not evaluate the economics of choosing the [redacted] bid in the 2024 Request for Proposals for Energy and Capacity from Existing Generation Resources ("2024 RFP") in lieu of Lone Star, and thus, it was not shown as uneconomic in that scenario.[137] The evidence demonstrates the exact opposite. The [redacted] bid was, in fact, compared to Lone Star. The summary of the economic evaluation of the 2024 RFP makes clear that the [redacted] bid was compared to "the levelized cost of a new build CT based on ETI's current filing," *i.e.* the Lone Star CT.[138] As the PFD notes, the [redacted] bid was uneconomic relative to Lone Star and, therefore, could not reasonably "obviate or

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[134] PFD at 59.

[135] ETI Ex. 26A at 25-27 (Weaver Rebuttal); ETI Ex. 30A at 15-16 (Kline Rebuttal).

[136] PFD at 59.

[137] *Id.*

[138] ETI Ex. 26A at 67 (Weaver Rebuttal).

delay the need for Lone Star."[139] Further, the 2024 RFP solicited acquisitions,[140] but none were bid that "could obviate or delay the need for Lone Star." Thus, in the one instance in which an existing resource could be compared to a single resource in the Dispatchable Portfolio, the bid for that existing resource proved uneconomic. The only logical conclusion that can be drawn from those facts is that Lone Star is cost-effective compared to the existing resource.

As to the more recent [redacted][141] [redacted] Regardless, the record is clear that ETI's growing resource need in the Western Region causes any [redacted] resource to be considered in addition to, not in lieu of, Lone Star.[142] And, the planned SETEX transmission project does not change that conclusion. That transmission project is planned to be complementary with incremental generation to shore up Western Region reliability.[143] Indeed, even with SETEX and Lone Star in service, load in both the summer and winter load serving capability forecasts quickly approaches the limit of load serving capability in ETI's Western Region.[144]

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[139] PFD at 59. The Independent Monitor for the 2024 RFP concurred with the Company's determination that the [redacted] was uneconomic. ETI Ex. 29A at 21-22 (Nguyen Rebuttal).[140] ETI Ex. 26 at 77 (Weaver Rebuttal).

[140] ETI Ex. 26 at 77 (Weaver Rebuttal).

[141] *E.g.*, compare different gas indices and adders in ETI Ex. 26C_WP_Q16 (Weaver Rebuttal) and ETI Ex. 29A_WP_Table 1 (Nguyen Rebuttal).

[142] ETI Ex. 26 at 23 (Weaver Rebuttal); ETI Ex. 30 at 17-21 (Kline Rebuttal).

[143] *Id.*

[144] ETI Ex. 30 at 17 (Kline Rebuttal).

4. Cost of Dispatchable Portfolio Compared to Similar Technology

The PFD's conclusion that the Dispatchable Portfolio is expensive compared to similar technology fails to properly consider and weigh the evidence.[145] First and foremost, the PFD gives no consideration to the fact that the major plant equipment was the subject of a competitive solicitation, the merits of which the PFD recognizes in other contexts.[146]

The Company used the PIE RFP to obtain competitive pricing on major plant components that are needed to develop dispatchable generation in a time frame that would achieve 2028 in-service dates.[147] The PIE RFP sought bids from the only three original equipment manufacturers that could offer equipment that meets ETI's needs, constituting a significant portion of the cost of the Dispatchable Portfolio.[148] As ETI witness Carlos Ruiz points out, these were the only non-EPC cost components of the Dispatchable Portfolio where potential variances would occur,[149] and thus the PIE RFP was a reasonable method to ensure ETI identified the lowest-cost options for these projects. None of the parties have taken issue with the development and implementation of the PIE RFP nor the selection of the Mitsubishi Power America proposal from the PIE RFP. The PFD's refusal to consider the PIE RFP is error.

Second, with respect to the major non-PIE costs, ETI 1) used an open book process that allowed the project team full access to the EPC estimate and cost justifications, allowing for full transparency into how the costs were determined; and 2) hired an independent engineer and

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145 PFD at 65-66.

146 PFD at 33-34, 55, 60 and 67.

147 ETI Ex. 4 at 22-23 (Weaver Direct); ETI Ex. 6 at 40 (Ruiz Direct); ETI Ex. 27 at 12-13 (Ruiz Rebuttal).

148 ETI Ex. 6 at 40 (Ruiz Direct).

149 ETI Ex. 27 at 14 (Ruiz Rebuttal).

utilized industry data to assess the reasonableness of those costs.[150] The check estimate performed by Black & Veatch and the benchmarking analysis performed using data obtained from Power Advocate showed that the estimated non-PIE EPC costs of Legend and Lone Star are cost-competitive with the market.[151] Based on the Power Advocate benchmarking data, the construction cost estimate for Legend presented in ETI's supplemental filing is consistent with market pricing for similar projects and competitive with other pricing from that time period.[152] Two primary benchmarks were evaluated with Power Advocate: (1) Contractors G&A and Fee; and (2) EPC contingency. The Contractors G&A and Fee was found to be within the benchmarking range at 1.3% below the high end of the range, while the EPC contingency was found to be 0.2% above the average.[153] The Black & Veatch check estimate compared quantities, rates, labor hours, equipment cost and total costs with the EPC consortium estimate. This comparison, with adjustments made for comparability, indicates that the EPC Consortium's estimate is indeed competitive.[154]

The PFD's reliance on TIEC's arguments to dismiss the Black & Veatch check estimate and cost benchmarking is misguided.[155] First, the check estimate intentionally omitted major plant equipment because those costs were the subject of the competitive PIE RFP.[156] AFUDC and owner's cost were also intentionally omitted because those costs are ETI costs separate and

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[150] ETI Ex. 6 at 30 (Ruiz Direct).

[151] ETI Ex. 27 at 7 (Ruiz Rebuttal); ETI Ex. 6 at 28-30 (Ruiz Direct).

[152] ETI Ex. 6 at 30 (Ruiz Direct).

[153] *Id.*

[154] *Id.*

[155] PFD at 65-66.

[156] ETI Ex. 6 at 30 (Ruiz Direct).

apart from the EPC costs.[157] And, there was no need to include the Lone Star CT in the check estimate because Legend includes a CT that can be evaluated on the same basis as the Lone Star CT.[158] Thus, the scope of the check estimate was both proper and reasonable.

Second, TIEC's argument improperly isolates limited cost categories and, more importantly, fails to appreciate that the check estimate was based on completed projects and prior bids that did not reflect more recent market escalation. When that is accounted for, there is less than [redacted] variance between the results of the open book process and the independent check estimate.[159] Moreover, the approach of using a check estimate to validate the open book process, together with the comparison to benchmarking data, is comparable to steps ETI took with OCAPS as a means to ensure the reasonableness and cost-competitiveness of the OCAPS EPC costs.[160] The combination of the PIE RFP, check estimate and benchmarking provide assurance that the EPC costs (inclusive of major plant equipment) are reasonable.

The PFD's reliance on Energy Information Administration ("EIA") data to assess cost competitiveness is equally misguided.[161] Generic cost estimates from the EIA—which inherently include some time lag—are not reliable comparisons to the EPC Consortium's estimate of the EPC costs.[162] The EIA estimates are based on similar technology projects at non-specific locations, while the Legend and Lone Star estimated costs are site- and project-specific and come from firm bid costs that have now been finalized through execution of the EPC contracts.[163]

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[157] *Id.* at 21-30.

[158] *Id.* at 8 and 17. Both Legend and Lone Star will use a MPA 501 JAC CT.

[159] TIEC Ex. 1A at 250-259 (Griffey Exhibit CSG-2, Entergy Open Book Estimate Evaluation).

[160] ETI Ex. 27 at 7-8 (Ruiz Rebuttal).

[161] PFD at 66.

[162] ETI Ex. 27 at 6 (Ruiz Rebuttal).

[163] *Id.* at Exhibit CR-R-1 (Ruiz Rebuttal).

Finalizing the EPC contracts provides incremental cost certainty for the Dispatchable Portfolio and substantially reduces the overall risk of material cost overruns. Indeed, according to the AACE cost estimate classification system, the EPC pricing for Legend and Lone Star is the highest level of maturity and accuracy. In stark contrast, the EIA cost estimates are the lowest level of estimate in terms of maturity and accuracy. Specifically, the Legend and Lone Star estimates are expected to have an accuracy range of -10 to +15% (excluding transmission cost), while the EIA estimates have an accuracy range of -50 to +100%.[164] The PFD concludes that this only goes to the "level of accuracy" of the EIA estimate, "but does not account for the magnitude of the difference" between EIA generic project cost estimate and the more certain site-specific estimates for Legend and Lone Star.[165] That conclusion is illogical. If the EIA estimate is understated by 100%, adjusting for that inaccuracy would most certainly reduce the "magnitude" of the differences.

Finally, the PFD makes a comparison of Lone Star's cost to a J-class CT project announced by Arkansas Electric Cooperative Corporation ("AECC") without any evidence as to the class of that estimate in the AACE classification system or the scope of costs included in the AECC estimate to know whether that estimate is comparable to Lone Star.[166] Without more details regarding the scope of this project, including a clear breakdown of the costs across different categories of materials, equipment and labor, any comparison to the costs of Legend and Lone Star is invalid.[167]

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[164] ETI Ex. 27 at 6-7 (Ruiz Rebuttal).

[165] PFD at 66.

[166] *Id.* at 65-66.

[167] ETI Ex. 27 at 10 (Ruiz Rebuttal).

The project cost comparisons made by TIEC and relied on by the PFD show that generic project estimates and various announced projects will yield a wide range of project costs.[168] Doing so does not establish that those at the bottom end of a range are cost competitive but those at the top are not. It is overly simplistic for the PFD to surmise that a difference in project cost, regardless of the class or quality of the estimate, is indicative of cost competitiveness. These unsubstantiated comparisons cannot outweigh the totality of the mature site-specific cost estimates of Legend and Lone Star projects, the competitive solicitation for the PIE, and the independent check estimate and benchmarking for the project-specific non-PIE EPC costs.

C. Probable Lowering of Cost to Consumers

When the cost of a truly feasible alternative is compared to the Dispatchable Portfolio, ETI's analysis shows that the Dispatchable Portfolio is an overwhelmingly better choice—it will save customers hundreds of millions of dollars as shown in Table 4 below:

Table 4

GAS / CO_2 SCENARIO	**NET BENEFIT (NPV, 2024\$)**
REFERENCE GAS / REFERENCE CO_2	\$280.8 MM
REFERENCE GAS / NO CO_2	\$135.0 MM
LOW GAS / NO CO_2	\$101.7 MM
HIGH GAS / NO CO_2	\$360.3 MM
HIGH GAS / HIGH CO_2	\$571.4 MM

The PFD erred in failing to accord ETI's analysis due weight.

[168] TIEC Ex. 1 at 051 (Griffey Direct).

The PFD unreasonably dismisses ETI's analysis because it speculates that ETI's use of three CTs as the change case in the economic evaluation of the Dispatchable Portfolio may not be "a useful comparison," and thus "gives little weight" to it.[169] That conclusion is inconsistent with standard industry practice, which utilizes CT technology as a well-known yardstick to ascertain whether a proposed project is economic.

While the PFD properly recognizes that a "do nothing" case is not the proper comparison point,[170] it fails to appreciate how the industry generally identifies the alternative. It is industry-accepted practice to identify the cost of new entry ("CONE") as the lowest cost option to add incremental capacity to the market. It is also industry-accepted practice to use CT technology to determine CONE. ERCOT does so in its resource adequacy construct at the direction of Commission Staff,[171] and MISO does so for its resource adequacy construct.[172]

Consistent with this industry-accepted practice, ETI's economic analysis of the Dispatchable Portfolio properly compares the resources proposed to satisfy its reliability needs to the utility's lowest cost alternative for incremental capacity. ETI also used the same economic analysis framework as was used for MCPS and OCAPS – comparison of the proposed resource to CT capacity because CT capacity is considered the lowest cost option for incremental capacity.[173] In other words, proposed resources are compared to CTs to provide a common

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[169] PFD at 74-75.

[170] PFD at 74.

[171] *Reliability Standard for the ERCOT Market*, Project No. 54584, Staff Memorandum (July 11, 2024); TIEC Ex. 1 at 231-232 (Griffey Direct).

[172] https://cdn.misoenergy.org/20240923%20RASC%20Item%2003%20CONE%20and%20Net%20CONE%20Update649247.pdf.

[173] ETI Ex. 7 at 7-8 (Nguyen Direct); ETI Ex. 29 at 4 (Nguyen Rebuttal); *see, e.g.*, Docket No. 52487, PFD at 103.

measure of customer net benefits relative to a known, feasible alternative. It does not suggest the utility failed to consider other alternatives as well.

The Commission should reject the PFD's assessment that a three CT change case may not "be a viable alternative to the Dispatchable Portfolio," as well as its conclusion that ETI did not adequately explain why three CTs is the appropriate comparison in this case.[174] The three CT change case is a viable alternative for the capacity provided by the Dispatchable Portfolio because it considers the appropriate size and locational needs that the Dispatchable Portfolio is being proposed to address.[175] Moreover, as discussed above, the use of the generic CT technology is consistent with industry-accepted practice and also viable because the CTs that Mr. Nguyen analyzed could feasibly address ETI's resource needs, whereas the F-frame technology cannot.

To support his analysis, ETI witness Mr. Nguyen developed site-specific cost assumptions associated with siting two CTs at the Legend site in lieu of a CCCT, and the PFD accepted his associated cost assumptions and calculations and correctly rejected TIEC's criticisms of Mr. Nguyen's calculations.[176]

Table 4 above summarizes his analysis of customer net benefits across a range of reasonable commodity market assumptions. No other party presented evidence of site-specific costs for viable alternatives to Lone Star and Legend. Thus, the preponderance of the evidence in the record demonstrates that the Dispatchable Portfolio is expected to provide significant

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[174] *See* PFD at 74-75.

[175] *See* ETI Exhibit 7 at 7-8 (Nguyen Direct).

[176] PFD at 73-74; ETI Ex. 29 at 7 (Nguyen Rebuttal).

savings to ETI customers, which is sufficient for the Commission to conclude that the Dispatchable Portfolio will result in a probable lowering of costs to consumers.[177]

D. Other CCN Factors

No Exceptions.

E. Administrative Law Judges' Overall Analysis of CCN Factors

The PFD concludes that the purportedly inadequate consideration of alternatives outweighs ETI's capacity need, the probable improvement in service and reliability, and all other CCN factors combined.[178] And while ETI *has* demonstrated the Dispatchable Portfolio is the lowest *reasonable* cost alternative, there can be no clearer example of elevating part of one CCN criterion as "absolute" in violation of Commission and court precedent. That error is compounded because the PFD's consideration of alternatives, as discussed above, is based on a misapplication of Commission decisions from two renewable cases,[179] and is inconsistent with the Commission's Preliminary Order.[180] The PFD also acknowledged that it gave little weight to ETI's economic analysis, which bears on another explicit CCN factor (probable lowering of costs).[181] As explained in Section IV.C. above, that decision fails to appropriately weigh the evidence and ignores industry standards. Thus, the PFD failed to appropriately balance the CCN factors, misapplied Commission precedent, afforded little to no weight to the uncontested evidence regarding ETI's substantial capacity needs and reliability improvements, and improperly discounted the economic benefits showing a probable lowering of costs. When the

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177 ETI Ex. 20 at 8 (Nguyen Supplemental).

178 PFD at 78.

179 *Id.* at 77 and 79.

180 Preliminary Order issues No. 19.b. and 31.

181 PFD at 78.

CCN factors are properly balanced, and appropriate consideration is given to resource planning experts familiar with ETI's system over conjecture and irrelevant cost comparisons, the preponderance of the evidence shows that granting the CCN application to construct the Dispatchable Portfolio is necessary for the service, accommodation convenience, or safety of the public. For that reason, ETI's application should be approved timely and without condition.

V. PROPOSED CONDITIONS

A. Cost Cap and Prudence Review

1. Cost Cap

The PFD appropriately rejected TIEC's proposed "soft cost cap" recommendation as well as any notion of a hard cost cap.[182] The PFD goes on to propose, however, that if the Commission approves the CCN request, that it "clarify that in a subsequent rate case, ETI will retain the burden of proof to show that … it was prudent to ***select*** Legend and Lone Star and to incur the costs to construct them."[183] Such a result is wholly inconsistent with PURA, decades of Commission precedent, the existing regulatory paradigm, and the assurance utilities must have to make investments of this magnitude. **If utilities do not receive up-front approval of their selection of a particular generating unit, dispatchable generating units costing hundreds of millions of dollars or more will not be built.** As discussed below, utilities of course retain the obligation to prudently manage such projects, including adjusting to material changes in the circumstances present at the time of the CCN approval, which could include cancelling the project. But if billion-dollar generation investments are to be made, there can be no "second guessing" or relitigation that the utility's initial decision to construct a specific project, based on

[182] PFD at 89.

[183] *Id.* at 90 (emphasis added).

already known circumstances, was not prudent, such that potential future cost recovery could be $0. Such a condition is equivalent to TIEC's rejected "soft cost cap" but *worse*, as it entirely eliminates the decisional prudence associated with a CCN approval. Such a result would not only be contrary to the law; it would be disastrous policy.

The PFD states that no party has cited to precedent indicating that a utility enjoys a presumption that its selection of resources is prudent simply because the utility received Commission approval to include the resource in its CCN, and they cite to two court cases as "appear[ing]" to establish precedent to the contrary.[184] ETI respectfully disagrees. Those cases support the longstanding legal principle and Commission practice, that, after the Commission grants a CCN amendment under PURA § 37.056 — finding that constructing the *proposed resource* is necessary for the service, accommodation, convenience, or safety of the public — the prudence question addressed in the subsequent rate case is whether the utility managed the approved project in a prudent manner. There is no relitigation of whether the utility should have pursued a different resource in the first instance. Indeed, the Texas-New Mexico Power Company case cited in the PFD states:

> The certificate of convenience and necessity affords only **the right to begin construction**, not a guarantee that every inefficient or imprudent expenditure will be passed on to the consuming public. When a new installation begins supplying service, the PUC must still determine **what portion** of the investment is properly chargeable to ratepayers with the burden of proving "the prudence and reasonableness of [each element of] its expenditures" firmly fixed on the utility. [Citation omitted.] Hence ratepayers such as TIEC are afforded safeguards as the Commission establishes "just and reasonable" rates in accord with the statutory factors.[185]

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[184] PFD at 88-89.

[185] *Tex.-New Mexico Power Co. v. Tex. Indus. Energy Consumers*, 806 S.W.2d 230, 233 (Tex. 1991) (emphasis added).

The Supreme Court recognized that the CCN granted the utility the right to construct the resource. Nowhere does the opinion state or imply that subsequent review of expenditures involved in constructing the resource includes another round of litigation to determine whether it was prudent to select or proceed with that project in the first place. In this instance, that would amount to telling ETI, "Go forth and make this investment of more than $2 billion and you'll find out later if those were the right power plants to build." Rather, the Supreme Court simply describes the well-understood process whereby the utility's management of the project and actual costs incurred are reviewed. Similarly, the Entergy Gulf States case cited in the PFD involved a review of whether costs that *exceeded* the estimate to build the River Bend Nuclear Power Station ("River Bend") were prudent.[186] Nowhere does that opinion state or imply that review of the original selection of River Bend was subject to another review after it was approved. Indeed, the court recognized prior Supreme Court holdings that the doctrines of *res judicata* and collateral estoppel bar re-litigation of issues from one PUCT proceeding to the next.[187]

This framework is further clarified in another Texas Supreme Court case where the court found:

> For example, if a certificate of convenience and necessity (CCN) to construct a new plant is granted, the costs of the new plant will eventually be considered in setting future rates. However, **the approval of construction** does not constitute a ratemaking proceeding subject to PURA section 43. [Citation omitted.] When a CCN is granted, **the utility receives the right to invest capital in an asset** and upon completion of **the asset**, the amount of the investment found to be prudent will be placed in the utility's rate base. However, **that asset** will not be included in the utility's rate base until a rate hearing is conducted and the Commission determines that the costs of building **the asset** are prudent, reasonable and necessary and related to property that is used and useful in providing service.[188]

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[186] *Entergy Gulf States, Inc. v. Pub. Util. Comm'n of Texas*, 112 S.W.3d 208 (Tex. App.—Austin 2003, pet. denied).

[187] *Id.* at 212.

[188] *State v. Pub. Util. Comm'n of Texas*, 883 S.W.2d 190, 198 (Tex. 1994) (emphasis added).

Thus, the precedent does not suggest that the initial decision to construct the plant after obtaining approval in the CCN case is subject to re-litigation. Rather, the precedent recognizes that a utility has the obligation to make ongoing prudent project management decisions, which would include abandoning a project altogether if changed circumstances warrant that result. However, Commission's evaluation of the prudence of those prospective decisions is very different from the proposed retroactive re-litigation of the initial decision to construct a plant post-CCN approval.

As noted above, policy considerations preclude re-litigation of the selection process after the CCN proceeding. As the PFD noted, when a utility undertakes hundreds of millions to billions of dollars in generation investment, it needs assurance that its choice of action will not be subject to re-litigation.[189] Put more directly, utilities will not invest hundreds of millions to billions of dollars in a generation plant without reasonable assurance of cost recovery. If cost recovery can be denied based on hindsight and second-guessing in a rate case that takes place years down the road, it is difficult to imagine any rational utility in this state investing, for example, $2.4 billion in new dispatchable gas generation. The entire purpose of the CCN proceeding is to establish that construction of generation is the public interest *before* it is built. If the Commission finds that building the proposed project is in the public interest and grants a CCN, that decision should not be subject to re-litigation. The Supreme Court also recognized that principle: "Reflecting the consummation of six weeks of administrative hearings, the certificate imposed a clear obligation on the utility and fixed its legal relationship."[190]

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[189] PFD at 86.

[190] *Tex.-New Mexico Power Co. v. Tex. Indus. Energy Consumers*, 806 S.W.2d at 233 (Tex. 1991).

The recommended condition is bad policy for another reason. This CCN application was filed on June 4, 2024.[191] Over the last year, the parties have filed rounds of testimony, engaged in a lengthy discovery process, participated in a hearing on the merits, submitted extensive briefs and reply briefs, and are now engaged in briefing on exceptions. The PFD's proposal would require essentially the same process again, though in the compressed timeframe of a rate case with a multitude of unrelated issues. For stakeholders with constrained time and resources, such as the Commission and Staff, this would introduce an incredibly inefficient process in which each CCN application is essentially litigated twice. It is also contrary to the Commission's emphasis on contemporaneous evaluation of prudence, not based on hindsight. That is, as recognized by the PFD, the Commission evaluates prudence based on the facts known at the time of the decision.[192] Re-litigation of the initial decision does not make sense under those parameters because the Commission has already done that analysis in the CCN case and, absent a material omission of something known at the time of that decision (which is not alleged here), there is no reason it would arrive at a different conclusion. It is difficult to comprehend a more wasteful expenditure of time and resources.

2. Prudence Review

The PFD recommends adoption of Staff's and OPUC's condition that ETI fund a third-party prudence review if the final costs of the Dispatchable Portfolio exceed $2.401 billion by more than 10%, which is the same condition that the Commission approved in a renewable case, Docket No. 55255.[193] The PFD's rationale is that it is reasonable for ETI to defray the

[191] *See* PFD at n.10.

[192] PFD at 88.

[193] *Id.* at 90. Note that in Docket No. 55255 the utility, SPS, agreed to the condition. *See* Docket No. 55255, SPS's Response to Exceptions to Proposal for Decision at 9 (Jun. 11, 2024) (PUC Interchange Item No. 312).

Commission's cost of evaluating the projects if that threshold is exceeded.[194] ETI fails to see the logic. In a rate case, the parties and Commission Staff will review the prudence of the resources' costs regardless of the level of those costs. The logic seems to be that the costs of such a review will somehow be higher, or the work harder, if the project costs exceed estimates. No party presented any evidence to support that rationale. To the contrary, the Staff witness admitted that it is an arbitrary threshold intended to punish the utility if the estimate, which is compiled years before the project is ultimately completed, is inaccurate (on the high side — no reward if on the low side).[195] There is simply no evidentiary support for this position.

To make matters worse, Staff confirmed that even if a prudence review were triggered, and the consultant concluded that the costs were prudent, ETI should nonetheless be penalized and not allowed recovery of the consultant costs.[196] That result is contrary to PURA, which entitles utilities to recover prudent, reasonable, and necessary costs.[197] While, depending on the circumstances, parties may determine such a condition is an acceptable component of a settlement, the Commission should not impose such a condition in a litigated case.

B. Competitive Tariff Proceeding

No Exceptions.

C. Hydrogen and Carbon Capture and Storage

The PFD concluded that the circumstances in this CCN application are "analogous" to the circumstances in Docket No. 52487 and therefore recommend that the Commission require ETI to seek a future CCN amendment if ETI intends to implement hydrogen operations at either

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[194] PFD at 90.

[195] Tr. at 286:35 – 287:4 (Ghanem Cross) (Apr. 8, 2025).

[196] *Id.* at 287:18-23.

[197] PURA § 36.051.

Legend or Lone Star or carbon capture and storage ("CCS") at Legend.[198] The circumstances with respect to hydrogen co-firing and CCS are not analogous. In Docket No. 52487, the OCAPS proceeding, ETI sought to include incremental costs necessary to operate the plant on hydrogen,[199] and the PFD in that case found that hydrogen co-firing was not a necessary component of the plant.[200] The Commission agreed and denied ETI's request for incremental investment necessary to operate the plant on hydrogen but added a condition that ETI could amend its CCN in the future to add hydrogen co-firing capability if circumstances changed.[201]

In this case, there are no incremental costs for hydrogen co-firing included in ETI's application, and ETI has not sought authority to implement it. The same is true for CCS. ETI's application does not include any costs for CCS implementation, and ETI has not requested authority to implement it. Thus, unlike OCAPS where the Commission denied ETI's request but felt the need to make it clear the denial was without prejudice by specifically allowing ETI an opportunity to amend its CCN if circumstances change, there is nothing to deny here, and therefore no reason to condition or constrain ETI's future options. The Commission should decline these proposed conditions as irrelevant and unwarranted under the circumstances of this case.

D. Weatherization

No Exceptions.

E. Electric Service for Lone Star

No Exceptions.

[198] PFD at 103.

[199] Docket No. 52487, PFD at 90.

[200] *Id.* at 98.

[201] Docket No. 52487, Order on Rehearing at 4.

F. Rate-Case Expenses Related to Supplemental Application

No Exceptions.

G. Reporting Requirements

No Exceptions.

H. TPWD's Recommendations

No Exceptions

VI. PROPOSED GOOD-CAUSE EXCEPTION TO GCRR RULE

The Commission should grant ETI's request for a good-cause exception[202] to the Generation Cost Recovery Rider ("GCRR") rule ("GCRR Rule"),[203] or clarify that a good-cause exception is not necessary, to effectuate the Legislature's intent for that mechanism to reduce regulatory lag and ensure timely cost recovery.[204] The PFD correctly concludes that absent an exception to the GCRR Rule, ETI's choice of customer-beneficial financing[205] for Legend will result in an extended cost recovery delay for Legend until after a GCRR update has been processed.[206] The PFD nevertheless finds that ETI's good-cause request should not be granted because ETI did not meet its initial burden to show good cause. As its basis, the PFD disputes ETI's showing of financial and operational harm arising from the delay.[207] In fact, ETI provided uncontested evidence of this harm.

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[202] 16 TAC § 25.3(b).

[203] 16 TAC § 25.248.

[204] PFD at 127 ("The purpose of a GCRR is to reduce regulatory lag and facilitate timely cost recovery by allowing a utility to recover its investment in a generation facility on the day that the plant is placed in service.").

[205] ETI witness Duncan Blake-Finley explains the benefits of this financing approach. ETI Ex. 11 at 10 (Sperandeo Direct adopted by Blake-Finley). *See also* Tr. at 253 (Blake-Finley Cross) (Apr. 8, 2025).

[206] PFD at 128.

[207] *Id.*

The PFD misunderstands the facts in evidence. It is uncontested that ETI's 2028 FFO/Debt metric drops [redacted] in ETI's modeling of a delayed GCRR update.[208] This is a meaningful reduction and quantifies not only financial, but operational risk for ETI. Both the PFD and Staff focus on the fact that ETI's modeling does not result in a credit downgrade.[209] But the avoidance of a credit downgrade was never the basis for ETI's good-cause request. The reduction in cash flow and corresponding effect on credit metrics will hamper ETI's ability to fund other capital projects while it waits for cost recovery associated with Legend, and the limited cash flow during this period will strain ETI's working capital, affecting ETI's ability to pay suppliers, maintain infrastructure, and invest in necessary infrastructure upgrades.

In that cash constrained scenario, ETI may need to secure short-term financing to cover these capital and operational expenses, leading to higher interest expense,[210] and ETI would not be made whole for those costs arising from a wholly avoidable delay in cost recovery for Legend that is only occurring because of ETI's choice of a customer-beneficial financing structure. Again, the Legislature intended to eliminate lag and these adverse effects through creation of a GCRR, and ETI is simply asking the Commission to look through the transaction structure and recognize that it is customer-beneficial financing, which should be encouraged.

Indeed, the Commission should grant ETI's good-cause request because it would indicate to utilities that using customer-beneficial financing for critical dispatchable resources does not risk significantly delayed GCRR recovery. ETI has recognized since the outset of this case that

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[208] Staff Ex. No. 12 at 12 (ETI's Responses to Staff 7th RFI) ("[a]s shown in ETI's response to STAFF 7-1 where ETI modeled the [GCRR] timing consistent with prior GCRR filings, the Company's FFO/Debt credit metric will be even lower due to additional delays in revenues if the Company's request to look through the financing structure is not granted. In that scenario, the 2028 FFO/Debt metric drops [redacted] and gets close to the bottom of the target range.").

[209] PFD at 126 (citing Staff Ex. 3 (Ordonez Direct)) at 14-15; Staff Ex. 12; Staff Ex. 13.

[210] ETI Ex. 34 at 11 (Blake-Finley Rebuttal).

the Commission has previously declined to address ratemaking issues such as these in CCN proceedings.[211] However, ETI believes it is important policy for utilities across Texas to know prior to certification, in the resource planning stage, the cost recovery impacts of financing critical dispatchable facilities. Then, they can pursue the financing option that is in the best interest of their customers. This is why ETI's good-cause request is appropriate in this CCN proceeding and not, as the PFD suggests, a premature request "solely focused on [ETI] acquiring expedited rate relief."[212] ETI is concerned that denial of its request here would signal to Texas utilities that unlocking customer benefits through alternative financing puts the utility at risk of operating in a cash-restrained posture for the often-considerable processing time[213] of a GCRR update. That is bad policy at a time Texas is desperately in need of dispatchable resources and the opposite of the policy that led to the Texas Legislature's passage of the GCRR statute.

VII. CONCLUSION

For the reasons explained herein, the PFD should be rejected and ETI's application should be approved as filed and supplemented without delay or condition because ETI satisfied its burden of demonstrating by a preponderance of the evidence that granting the CCN is necessary for the service, accommodation, convenience, or safety of the public.

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[211] ETI Ex. 11 at 11 (Sperandeo Direct adopted by Blake-Finley).

[212] PFD at 126-127.

[213] ETI's two prior update applications for Montgomery County Power Station and the Hardin County Peaking Facility took 10 months and 12 months, respectively, to process. ETI Ex. 34 at 8-9 (Blake-Finley Rebuttal). Other utilities have experienced even longer delays. A GCRR update application filed by El Paso Electric Company in Docket No. 56225 took *more than a year* to process. *Application of El Paso Electric Company to Update its Generation Cost Recovery Rider Related to Newman Unit 6*, Docket No. 56255, Order (Jan. 31, 2025).

VIII. FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDERING PARAGRAPHS

A. PFD's Proposed Findings of Fact, Conclusions of Law, and Ordering Paragraphs

Consistent with ETI's Exceptions described herein, the following proposed Findings of Facts, Conclusions of Law, and Ordering Paragraphs are inconsistent with ETI's position and should not be adopted:[214]

- Findings of Fact: 69-72, 74, 78, 80-85, 87-90, 105-108, plus alternative Findings of Fact 109-119, 137.
- Conclusions of Law: 13-14, plus alternative Conclusions of Law 16, 19.
- Ordering Paragraphs 1-2, plus alternative Ordering Paragraphs 4-11.

Instead, ETI's proposed CCN amendment should be approved for the reasons discussed above, and the Company's proposed Findings of Fact, Conclusions of Law, and Ordering Paragraphs (filed May 1, 2025) should be incorporated into a Commission final order.

B. ETI's Proposed Findings of Fact, Conclusions of Law, and Ordering Paragraphs

In the event the CCN amendment is approved, the PFD recommends adopting the Texas Parks and Wildlife Department's ("TPWD") recommendations regarding the Dispatchable Portfolio, as modified by ETI witness Jeremy Halland's rebuttal testimony, and they requested proposed Findings of Fact, Conclusions of Law, or Ordering Paragraphs. Accordingly, ETI proposes the following Findings of Fact:

XX. On June 7, 2024, Entergy provided the environmental impact study or assessments for the Dispatchable Portfolio to the TPWD.

XX. On August 6, 2024, the TPWD filed comments and recommendations in this proceeding. The TPWD did not seek to intervene.

[214] PFD at 129-142 and Attachment A.

XX. Entergy Texas and the engineering, procurement, and construction company will consider the recommendations in the TPWD letter and incorporate those recommendations to the fullest extent consistent with best management practices in an effort to mitigate potential environmental impacts.

XX. To ensure the safety of personnel and wildlife in the Project areas of Dispatchable Portfolio and its safe and efficient operation, Entergy Texas will not implement the following recommendations from the TPWD letter:

> xxA. "To minimize impacts to water resources, TPWD recommends the project proponent avoid stream and wetland impacts, including avoiding using stream crossings for access roads, maintaining natural drainage patterns within the proposed project site, and implementing [best management practices] for preventing erosion and sedimentation during construction activities. TPWD recommends implementing at least a 50-foot buffer on intermittent streams and wetlands."
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> xxB. "TPWD recommends the project proponent establish sanitation procedures to prevent the spread of invasive plants. TPWD recommends such a plan include the following measures to minimize invasive plant spread: 1) Inspect the site for infestation prior to operations. 2) Avoid driving vehicles, mowers, all-terrain vehicles, or spray equipment through infestations in seed or fruit. 3) Brush and wipe all seeds and debris from clothes, boots, socks, and personal protective equipment. 4) Clean motorized equipment, especially the undercarriage and tire surfaces. 5) Cover loads or bag cut invasive plants before transport."

XX. The standard mitigation requirements included in the ordering paragraphs of this Order, coupled with Entergy Texas's current practices and best management practices, are reasonable measures to undertake when constructing the Dispatchable Portfolio station and sufficiently address the TPWD's comments and recommendations.

Respectfully submitted,

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ATTORNEYS FOR ENTERGY TEXAS, INC.

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Entergy Texas, Inc.'s Exceptions to the Proposal for Decision was served by electronic delivery on all parties of record in this proceeding on July 28, 2025.

Karis Anne Gong Parnham