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State Office of Administrative Hearings

Kristofer S. Monson
Chief Administrative Law Judge

June 30, 2025

Shelah Cisneros
Commission Counsel
Public Utility Commission of Texas

VIA EFILE TEXAS

RE: SOAH Docket No. 473-24-21530; PUC Docket No. 56693;
Application of Entergy Texas, Inc. to Amend its Certificate of Convenience and Necessity to Construct a Portfolio of Dispatchable Generation Resources

Dear Parties:

Please find attached a Proposal for Decision (PFD) in this case. By copy of this letter, the parties to this proceeding are being served with the PFD.

The Commission will place this case on an open meeting agenda for the Commissioners' consideration. The Commission will notify the Administrative Law Judges and the parties of the open meeting date, as well as the deadlines for filing exceptions to the PFD, replies to the exceptions, and requests for oral argument.

Enclosure
CC: Service List

SOAH Docket No. 473-24-21530 Suffix: PUC
PUC Docket No. 56693

Before the State Office of Administrative Hearings

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

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ACRONYMS AND ABBREVIATIONS

TERM	DEFINITION
AECC	Arkansas Electric Cooperative Corporation
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
Application	ETI's application for a CCN amendment filed June 4, 2024
B&V	Black & Veatch
BP23	ETI's 2023 Business Plan
BP24	ETI's 2024 Business Plan
BP25	ETI's 2025 Business Plan
CAGR	Compound Annual Growth Rate
CCN	Certificate of Convenience and Necessity
CGS	Competitive Generation Service
Cities	The Cities of Anahuac, Beaumont, Bridge City, Cleveland, Conroe, Dayton, Houston, Liberty, Navasota, Nederland, Orange, Panorama Village, Pinehurst, Port Arthur, Port Neches, Shenandoah, Silsbee, Sour Lake, Splendora, and West Orange
CO_2	Carbon Dioxide
COL	Conclusion of Law
Commission	Public Utility Commission of Texas

CCCT	Combined-Cycle Combustion Turbine
CCS	Carbon Capture and Storage
CT	Combustion Turbine
Dispatchable Portfolio	Legend Power Station and Lone Star Power Station, collectively
EA	Environmental Assessment
EIA	Energy Information Administration
ELL	Entergy Louisiana, LLC
EPC	Engineering, Procurement, and Construction
EPC Consortium	Sargent & Lundy, The Industrial Company, and Mitsubishi Power America
EPE	El Paso Electric Company
ERCOT	Electric Reliability Council of Texas
ESL	Entergy Services, LLC
ETEC	East Texas Electric Cooperative, Inc.
ETI	Entergy Texas, Inc.
FERC	Federal Energy Regulatory Commission
FOF	Finding of Fact
G&A	General and Administrative
GCRR	Generation Cost Recovery Rider
kW	Kilowatt
Legend	Legend Power Station

Lone Star	Lone Star Power Station
LPSC	Louisiana Public Service Commission
MCPS	Montgomery County Power Station
MISO	Midcontinent Independent System Operator, Inc.
Mitsubishi	Mitsubishi Power America
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
O&M	Operations and Maintenance
OCAPS	Orange County Advanced Power Station
OP	Ordering Paragraph
OPUC	Office of Public Utility Counsel
PIE	Power Island Equipment
Power Engineers	Power Engineers, Inc.
PPA	Purchase Power Agreement
PURA	Public Utility Regulatory Act
RFI	Request for Information
RFP	Request for Proposals
Sam Houston	Sam Houston Electric Cooperative, Inc.
SCR	Selective Catalytic Reduction
SOAH	State Office of Administrative Hearings
SPS	Southwestern Public Service Company

SRP	Strategic Resource Plan
Staff	Staff of the Public Utility Commission of Texas
SWEPCO	Southwestern Electric Power Company
TAC	Texas Administrative Code
TIEC	Texas Industrial Energy Consumers
TPWD	Texas Parks and Wildlife Department
WOTAB	West of the Atchafalaya Basin

SOAH Docket No. 473-24-21530 Suffix: PUC
PUC Docket No. 56693

BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

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

PROPOSAL FOR DECISION

Entergy Texas, Inc. (ETI) filed an application with the Public Utility Commission of Texas (Commission) to amend its certificate of convenience and necessity (CCN) to construct, own, and operate two generating facilities:

1. Legend Power Station (Legend), a 754 megawatt (MW) combined-cycle combustion turbine (CCCT)[1] facility to be located in Jefferson County, Texas, enabled with carbon capture and storage (CCS) and hydrogen co-firing optionality, and

[1] The parties also refer to this technology as a combined-cycle *gas* turbine, or CCGT. The Administrative Law Judges (ALJs) use CCCT for consistency.

2. Lone Star Power Station (Lone Star), a 453 MW simple-cycle combustion turbine (CT) facility to be located in San Jacinto County, Texas,[2] enabled with hydrogen co-firing optionality.

Collectively, Legend and Lone Star are referred to as the Dispatchable Portfolio. ETI estimates that the Dispatchable Portfolio will cost $2.4 billion.[3]

No party disputes that ETI has a significant near-term need for additional capacity. The primary contested issue is whether ETI demonstrated that the Dispatchable Portfolio is a cost-effective alternative to meet that need.

Texas Industrial Energy Consumers (TIEC), the Office of Public Utility Counsel (OPUC), and Commission staff (Staff) all raise concerns with how the Dispatchable Portfolio was selected, particularly the fact that ETI did not conduct a request for proposals (RFP) to determine which projects to pursue. They each take a slightly different approach as to how the Commission should address this issue. Staff recommends that the application be denied but requests that conditions be imposed if it is approved.[4] TIEC notes that ordinarily the failure to demonstrate that the Dispatchable Portfolio is an appropriate alternative would result in ETI's application being denied.[5] However, it is not clear whether sufficient time remains to restart the planning process and meet the capacity need that ETI has identified as

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[2] In its application, ETI initially proposed that Lone Star would be located in Liberty County, Texas, but as discussed below, ETI now plans to construct the plant in San Jacinto County instead. *See* ETI Ex. 25 (Viamontes Reb.) at 12.

[3] ETI Ex. 18 (Ruiz Supp. Dir.) at 16, 24.

[4] Staff Initial Brief at 1-2.

[5] TIEC Initial Brief at 3-4.

early as 2028, thus TIEC advises that the Commission could choose to approve ETI's application, but only with certain conditions. OPUC does not take a position on whether the Commission should approve or deny the application, but requests that conditions be imposed to protect customers if it is approved.[6]

Regarding the remaining parties, East Texas Electric Cooperative, Inc. (ETEC) entered into a partial settlement agreement with ETI and supports approval of the application;[7] Sam Houston Electric Cooperative, Inc. (Sam Houston) does not take a position on the application, but recommends a condition be imposed related to Lone Star's operations if the application is approved since the plant would be located in Sam Houston's retail electric service area;[8] and Cities and Sierra Club do not take a position on the application or conditions.[9]

After considering the evidence and applicable law, the Administrative Law Judges (ALJs) conclude that ETI did not meet its burden of proof to show that the Dispatchable Portfolio is a cost-effective alternative to meet its need for additional service. Therefore, the ALJs recommend that ETI's application be denied. However, the evidence does show that ETI has an imminent need for additional

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[6] OPUC Initial Brief at 1-2.

[7] ETEC Statement of Position (Apr. 3, 2025) (stating that ETEC reached a partial settlement "to jointly participate with ETI in resources that are the subject of these proceedings"); *see also* ETEC Notice of Intent Not to File an Initial Post-Hearing Brief (Apr. 21, 2025).

[8] *See generally* Sam Houston Initial Brief.

[9] Cities' Notice of Intent Not to File Briefs (Apr. 21, 2025); Sierra Club's Statement of Position (Mar. 26, 2025). Cities refers to the Cities of Anahuac, Beaumont, Bridge City, Cleveland, Conroe, Dayton, Houston, Liberty, Navasota, Nederland, Orange, Panorama Village, Pinehurst, Port Arthur, Port Neches, Shenandoah, Silsbee, Sour Lake, Splendora, and West Orange.

capacity as early as 2028 and that sufficient time is likely not available to secure different resources to meet that need. Therefore, the Commission may conclude that the application should nevertheless be approved. In that event, the ALJs recommend that certain conditions be imposed regarding ETI's cost recovery for the Dispatchable Portfolio and requiring ETI to obtain Commission approval before implementing hydrogen co-firing or CCS.

I. JURISDICTION, NOTICE, AND PROCEDURAL HISTORY

Jurisdiction and notice were not contested and therefore are addressed only in the findings of fact (FOFs) and conclusions of law (COLs).

ETI filed its application on June 4, 2024.[10] On July 10, 2024, the Commission referred the case to the State Office of Administrative Hearings (SOAH) and the following day issued a Preliminary Order defining the scope of the issues to be considered.[11] The parties submitted an agreed procedural schedule, which was adopted.[12] On September 23, 2024, ETI filed a motion to extend the procedural schedule "to address certain scope and cost developments" related to both Legend

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[10] ETI Ex. 1 (Application). The application appeared on the Commission's Interchange on June 5, 2024; however, ETI filed it on June 4, 2025, and was required to resubmit it due to an upload error. *See* Letter from ETI to Central Records (June 5, 2024) (including filing receipts showing that the application was submitted before 3:00 p.m. on June 4, 2024); *see also* 16 Tex. Admin. Code § 22.71(e) (stating that pleadings and any other documents shall be deemed filed when the required number of copies and the electronic copy, if required, are presented to the Commission filing clerk for filing).

[11] Order of Referral (July 10, 2024); Preliminary Order (July 11, 2024).

[12] SOAH Order No. 3 (July 31, 2024).

and Lone Star.[13] The motion was granted, and the case was abated to give ETI time to address the issues.[14]

ETI supplemented its application on December 16, 2024, and thereafter filed an agreed procedural schedule and motion to resume the proceeding.[15] The ALJ granted ETI leave to amend its application, lifted the abatement, and adopted a procedural schedule.[16]

The hearing on the merits convened via videoconference on April 8-9, 2025, before SOAH ALJs Cassandra Quinn and Daniel Wiseman.[17] The record closed on May 1, 2025, with the filing of the parties' post-hearing reply briefs and proposed FOFs, COLs, and ordering paragraphs (OPs).

II. APPLICABLE LAW

An electric utility operating solely outside of the Electric Reliability Council of Texas (ERCOT) power region, like ETI, must obtain a CCN or amendment to an existing CCN to construct, own, or operate a generation facility with a capacity of

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[13] ETI's Motion to Extend Procedural Schedule (Sept. 23, 2024).

[14] SOAH Order No. 5 (Sept. 24, 2024).

[15] Motion to Adopt Agreed Procedural Schedule and Unopposed Motion to Resume the Proceeding (Dec. 20, 2024).

[16] SOAH Order No. 7 (Dec. 23, 2024).

[17] A hearing on ETI's companion application, Docket No. 56865, *Application of Entergy Texas, Inc. to Amend its Certificate of Convenience and Necessity to Construct a Portfolio of Renewable Generation Resources*, was held before ALJs Quinn and Wiseman on April 10, 2025. By agreement of the parties, the PFD in that docket is expected by August 1, 2025.

more than 10 MW.[18] The Commission may grant or amend a CCN if the certificate "is necessary for the service, accommodation, convenience, or safety of the public."[19] When making this determination, the Commission must consider the following factors set forth in Public Utility Regulatory Act (PURA) § 37.056(c):

(1) the adequacy of existing service;

(2) the need for additional service;

(3) the effect of granting the certificate on the recipient of the certificate and any electric utility serving the proximate area; and

(4) other factors, such as:

(A) community values;

(B) recreational and park areas;

(C) historical and aesthetic values;

(D) environmental integrity;

(E) the probable improvement of service or lowering of cost to consumers in the area if the certificate is granted, including any potential economic or reliability benefits associated with dual fuel and fuel storage capabilities in areas outside the ERCOT power region; and

(F) the need for extending transmission service where existing or projected electrical loads will be underserved.[20]

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[18] Public Utility Regulatory Act (PURA) §§ 37.051(a), .058(e). PURA is found at Texas Utilities Code §§ 11.001-66.016.

[19] PURA § 37.056(a).

[20] PURA § 37.056(c).

Additionally, in an ETI CCN proceeding, PURA § 39.452(j) requires that the Commission ensure that the proposed generation facility meets ETI's reliability needs and that the provisions of PURA § 37.056(c)(4)(D) and (E) are met.

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.[21]

After considering the listed factors, the Commission may grant the certificate as requested; grant the certificate for the construction of a portion of the requested facility or the partial exercise of the requested right or privilege; or refuse to grant the certificate.[22] The Commission may also impose conditions when granting a CCN.[23]

III. PROJECT DESCRIPTION

The Dispatchable Portfolio comprises Legend, a 754 MW CCCT resource, which will be enabled with CCS and hydrogen co-firing optionality, to be located in Jefferson County, Texas; and Lone Star, a 453 MW simple-cycle CT, which will be

[21] *Pub. Util. Comm'n of Tex. v. Texland Elec. Co.*, 701 S.W.2d 261, 267 (Tex. App.—Austin 1985, writ ref'd n.r.e.).

[22] PURA § 37.056(b).

[23] *See Sw. Elec. Power Co. v. Pub. Util. Comm'n*, 419 S.W.3d 414, 428 (Tex. App.—Amarillo 2011, pet. denied).

enabled with hydrogen co-firing optionality, to be located in San Jacinto County, Texas.

A. LEGEND

Legend will comprise one Mitsubishi Power America (Mitsubishi) 501 JAC CT, one Nooter Eriksen heat recovery steam generator with duct firing and selective catalytic reduction (SCR), and one Mitsubishi steam turbine generator configured in a 1x1 combined-cycle arrangement, along with other balance of plant equipment, including an air-cooled condenser for closed-cycle cooling operations. The Mitsubishi 501 JAC CT is designed to accommodate approximately 30% hydrogen co-firing, with potential future upgrades enabling 100% hydrogen firing capability. Furthermore, the site layout for Legend is designed to support the potential installation of CCS infrastructure in the future. There are currently no plans for on-site fuel storage facilities at the Legend site.

ETI's service territory is divided into two planning regions: the Eastern Region and Western Region. Legend will be located in ETI's Eastern Region, an area bordered by the Texas-Louisiana state border on the east, the Gulf of Mexico on the south, ETI's Western Region on the west, and the Southwest Power Pool on the north.

The construction of Legend will be undertaken by an Engineering, Procurement, and Construction (EPC) consortium consisting of Sargent & Lundy, The Industrial Company, and Mitsubishi (collectively, the EPC Consortium) under a recently executed fixed-price, fixed-schedule EPC contract.[24] The estimated total cost for the Legend project is approximately $1.602 billion, inclusive of allowance for funds used during construction (AFUDC). This total encompasses approximately $1.432 billion allocated to the generation component of the project, along with $22.5 million in estimated interconnection costs for connecting Legend to ETI's system at the switchyard, and $147 million in estimated transmission network upgrades.[25] The final cost of the transmission network upgrades required for Legend will be determined by the Midcontinent Independent System Operator (MISO).[26] Absent unforeseen delays, Legend is anticipated to commence operations by July 2028.[27]

After the application was filed, Legend's estimated cost rose by $139 million, as illustrated in the table below, due to changes in project scope arising from additional project development, including the need for additional equipment, costs associated with attracting area craft labor, modifications to equipment design, and rerouting of site drainage to avoid further wetland impacts:[28]

[24] ETI Ex. 27A (Ruiz Reb. HSPM) at 19-98.

[25] ETI Ex. 18 (Ruiz Supp. Dir.) at 14-16.

[26] ETI Ex. 6 (Ruiz Dir.) at 29; ETI Ex. 5 (Kline Dir.) at 53; ETI Ex. 30 (Kline Reb.) at 27-28.

[27] ETI Ex. 18 (Ruiz Supp. Dir.) at 9-10.

[28] ETI Ex. 18 (Ruiz Supp. Dir.) at 13, Table CR-S-2.

Table CR-S-2

Driver	Increase/(Decrease) ($M)
Civil scope design change	56
EPC cost adjustments since open book	70
Entergy Direct Costs	(11)
Entergy Indirect Costs	7
Removal of Mitsubishi Financing Costs	(42)
Financing costs	59
Total Additional Estimated Project Costs	**139**

The $56 million increase in "civil scope design change" reflects the need to develop an alternative design for Legend after geotechnical analyses conducted prior to the elevation of the project site for the construction of the plant's foundation indicated that the subsurface soils at the site are more compressible than initially estimated.[29]

The EPC cost estimate has also risen due to general market price escalations since the original estimate was prepared, as well as adjustments to EPC indirect costs. Additionally, there has been an increase in the original fuel reservation cost estimate for the period during construction and prior to commissioning, as these fees had not been negotiated at the time of the application. Furthermore, there is a $7 million increase in ETI costs and a $59 million increase in financing costs associated with Legend. Conversely, there has been a $15 million decrease in estimated ETI direct costs due to a reduction in project support staffing requirements during execution compared to initial plans. The $59 million increase

[29] ETI Ex. 18 (Ruiz Supp. Dir.) at 5.

in financing costs is partially offset by a $42 million decrease in financing costs resulting from ETI's decision to forgo deferral of payments to Mitsubishi for the Power Island Equipment (PIE) that includes the major components of the power plant.[30] The current project cost estimate continues to include a contingency to address any cost escalations beyond those already identified by ETI.[31]

B. Lone Star

Lone Star is proposed as a nominally sized 453 MW CT resource, to be located near ETI's existing Jacinto Substation in San Jacinto County, Texas. The facility will consist of one Mitsubishi 501JAC CT and one Mitsubishi generator in a simple-cycle configuration, along with other balance of plant equipment, including SCR and a generator step-up transformer. The CT will be capable of approximately 30% hydrogen co-firing, with the capability of future upgrades enabling 100% hydrogen firing capability.[32] There are currently no plans for on-site fuel storage facilities at Lone Star.

Like Legend, Lone Star will be constructed by the EPC Consortium under a fixed-price, fixed-schedule EPC contract, with an estimated total cost of $771.5 million, including AFUDC.[33] This total includes approximately $709 million allocated to the generation component of the project, along with $21 million in

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[30] ETI Ex. 18 (Ruiz Supp. Dir.) at 13-15.

[31] ETI Ex. 18 (Ruiz Supp. Dir.) at 15-16.

[32] ETI Ex. 6 (Ruiz Dir.) at 17.

[33] ETI Ex. 6 (Ruiz Dir.) at 17; ETI Ex. 18 (Ruiz Supp. Dir.) at 22-24.

estimated interconnection costs for connecting Lone Star to ETI's system at the switchyard, and $41 million in estimated transmission network upgrades.[34] As with Legend, the final costs of the transmission network upgrades required for Lone Star will be determined by MISO.[35] Subject to unforeseen delays, Lone Star is expected to commence operations by mid-2028.[36]

ETI's application initially identified a site for Lone Star in Liberty County; however, ETI has since determined that the San Jacinto County site is the most cost-effective and best overall option for several reasons.[37] While approximately five miles farther from the transmission interconnection point at the Jacinto Substation than the Liberty County property, the San Jacinto County site is in close proximity to the transmission line right-of-way.[38] Emission reduction and wetland mitigation costs associated with the Liberty County site, estimated to total $41.2 million, will be avoided by constructing Lone Star at the San Jacinto County site. The estimated difference in overall project costs between the two sites is approximately $27.5 million (roughly 3% of the total project cost), and no significant project milestone dates will change based on the site selection, as Lone Star will interconnect to the same substation regardless of the site.[39]

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[34] ETI Ex. 18 (Ruiz Supp. Dir.) at 24.

[35] ETI Ex. 6 (Ruiz Dir.) at 17; ETI Ex. 5 (Kline Dir.) at 53; ETI Ex. 30 (Kline Reb.) at 27-28.

[36] ETI Ex. 6 (Ruiz Dir.) at 33; ETI Ex. 18 (Ruiz Supp. Dir.) at 21.

[37] ETI Ex. 25 (Viamontes Reb.) at 28-33.

[38] ETI Ex. 18 (Ruiz Supp. Dir.) at 17-18.

[39] ETI Ex. 18 (Ruiz Supp. Dir.) at 18-20.

Lone Star has also experienced cost escalations similar to those that impacted the estimated costs for Legend between the time the application was filed in June 2024 and the supplemental application filing in December 2024. The incremental project cost increase for Lone Star (at the original Liberty County site) is approximately $63.7 million; however, given ETI's decision to proceed with siting Lone Star at the San Jacinto County site, the incremental increase is approximately $36.2 million, resulting in a total updated project cost of $771 million compared to the original estimate of $735 million included in the application.[40] The current project cost estimate continues to include a contingency to address any cost escalations beyond those already identified by ETI.

IV. CCN FACTORS

The contested issues in this case are relatively narrow. They essentially boil down to whether the Dispatchable Portfolio is a cost-effective alternative to meet ETI's need for additional service. While consideration of alternatives is not explicitly a CCN factor to consider under PURA § 37.056, it is inherent in the Commission's review of a CCN application and determining whether the specific proposed projects are necessary for the service, accommodation, convenience, or safety of the public. The key issues briefed by the parties are ETI's need for additional service, its consideration of alternatives, and the extent to which the Dispatchable Portfolio may lower costs for consumers. As such, those issues are discussed in detail first, followed

[40] ETI Ex. 18 (Ruiz Supp. Dir.) at 20-21.

by a brief discussion of the remaining CCN factors. The ALJs then provide their overall analysis balancing the factors.

A. Adequacy of Existing Service and Need for Additional Service

ETI's need for additional service is undisputed. However, because ETI relies heavily on this need as a justification for its selection of the Dispatchable Portfolio, the nature of that need is set out in detail below.

At present, ETI is adequately meeting its customers' service needs through a combination of owned and controlled generation resources and purchases from the market. However, ETI faces a significant and growing capacity deficiency driven by existing shortfalls, planned retirements of generating units, and forecasts indicating rapid load growth.[41] As illustrated in Figure 1 below, ETI's summer capacity need is projected to grow from approximately 800 MW in 2024 to approximately 1,500 MW in 2028. Similarly, Figure 2 shows that ETI's winter capacity need is expected to increase from approximately 1,200 MW in 2024 to approximately 1,600 MW in 2028.

[41] ETI Ex. 4 (Weaver Dir.) at 16.

Figure 1

Projected Summer Capacity Position

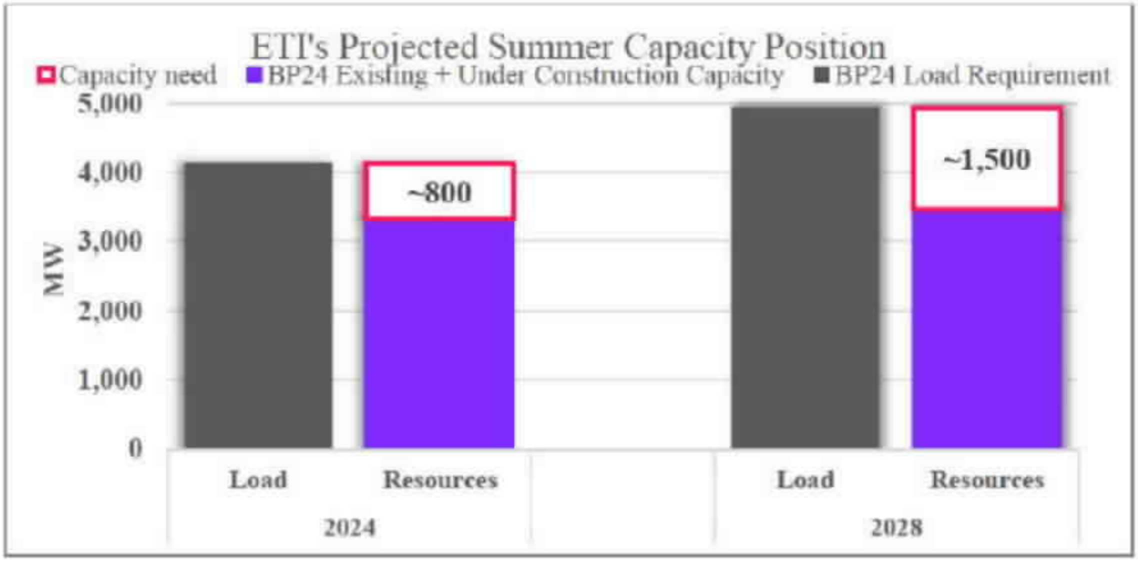
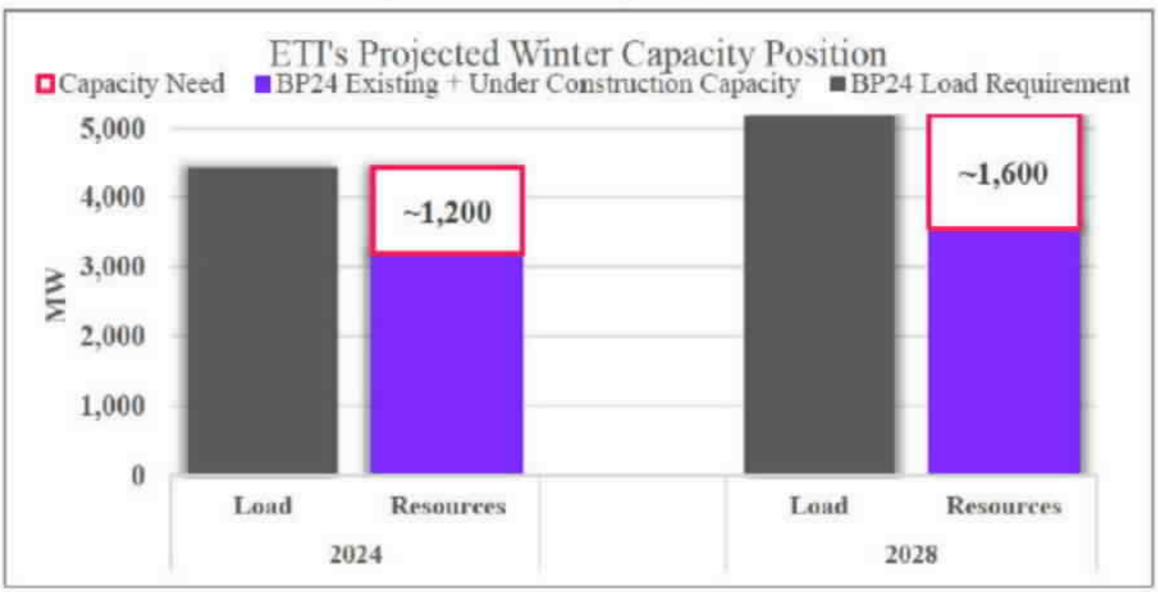


Figure 2

Projected Winter Capacity Position



Both seasonal projections indicate continued growth in capacity requirements, reaching approximately 2,400 MW by 2034. These projections are based on seasonal coincident peak load forecasts, corresponding reserve margin assumptions, and seasonal capacity ratings to account for changes in the MISO resource adequacy construct.[42]

ETI notes that a "confluence of events" drove the need for additional capacity and required it to act quickly to pursue the Dispatchable Portfolio. The passage of the Inflation Reduction Act in August 2022 spurred interest in industrial projects in ETI's service area, resulting in an increase to ETI's 2024 Business Plan (BP24) load forecast of approximately 100 MW in 2028. Around the same time, the Federal Energy Regulatory Commission (FERC) approved resource adequacy construct reforms proposed by MISO. The full extent of the effects of those reforms on ETI's capacity position was unknown until MISO completed its modeling in 2023. These developments were compounded when, in early 2023, ETI's counterparty to a long-term 225 MW purchase power agreement (PPA) canceled the agreement. Further, a large customer made a firm commitment to add 270 MW of load in 2027.[43]

In addition to capacity deficits, ETI projects an energy shortfall of nearly 9.7 terawatt-hours by 2028—an amount equivalent to approximately 35% of the total energy required to serve its customers. Absent the addition of new generating capacity, this energy deficit will continue to increase, exposing customers to greater risk from volatility in energy market prices.[44]

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[42] ETI Ex. 4 (Weaver Dir.) at 9-10.

[43] ETI Ex. 26 (Weaver Reb.) at 3-4.

[44] ETI Ex. 4 (Weaver Dir.) at 8.

Moreover, ETI's location within the westernmost portion of the MISO South region presents particular constraints. Specifically, ETI's service territory is fully contained within the West of the Atchafalaya Basin (WOTAB) planning region, which is considered a "load pocket," an area of heavy load concentration that, due to a limited ability to import power into the area, is dependent upon generation capability located within the region to serve the load in that area.[45] ETI explains that these limitations necessitate careful planning to ensure resource adequacy across ETI's service territory. For instance, ETI's Western Region experiences high residential and commercial air conditioning loads, while the Eastern Region includes large industrial and manufacturing loads—both of which require sufficient dispatchable generation to ensure the reliable delivery of real and reactive power.[46] The addition of Legend in the Eastern Region will provide reactive power to meet the needs in that region, and Lone Star will provide reliable service to the Western Region while avoiding the transmission constraints between the two regions.[47]

ETI's most recent load forecast indicates significant anticipated growth in both summer and winter peak loads. Specifically, ETI projects its summer coincident peak load to increase by approximately 19.7%—or 746 MW—by 2028 and by 29.5%—or 1,115 MW—by 2034. Similarly, the Company projects its winter coincident peak

[45] ETI Ex. 5 (Kline Dir.) at 7.

[46] *See* ETI Ex. 5 (Kline Dir.) at 8, 12, 14–15, 20–21, 23, 32, 39–40.

[47] ETI Ex. 5 (Kline Dir.) at 10-12.

load to grow by approximately 17.0%—or 590 MW—by 2028 and by 25%—or 866 MW—by 2034.[48]

This projected level of growth is driven in large part by substantial new and expanding industrial developments—particularly in the Port Arthur area, located within ETI's Eastern Region. According to the 2024 Business Plan forecast, energy requirements in the Eastern Region are expected to increase by 51%, with peak demand growing by 41%, which corresponds to a 10-year compound annual growth rate (CAGR) of 3.5%.[49]

At the time ETI filed its application in this proceeding, over 9,000 MW of potential new or expanded industrial load was under consideration to be added to the system by 2030.[50] While only a conservative portion of this total has been included in the forecast—due to uncertainty in customer expansion timelines—ETI had already executed energy service agreements for 603 MW of incremental load expected to be in service by mid-2028, coinciding with the anticipated in-service dates of the Legend and Lone Star facilities.[51] During the pendency of this proceeding, that contracted load increased to 902 MW.[52] Additional capacity is needed to serve these contracted loads.

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[48] ETI Ex. 4 (Weaver Dir.) at 13.

[49] ETI Ex. 10 (John Dir.) at 19.

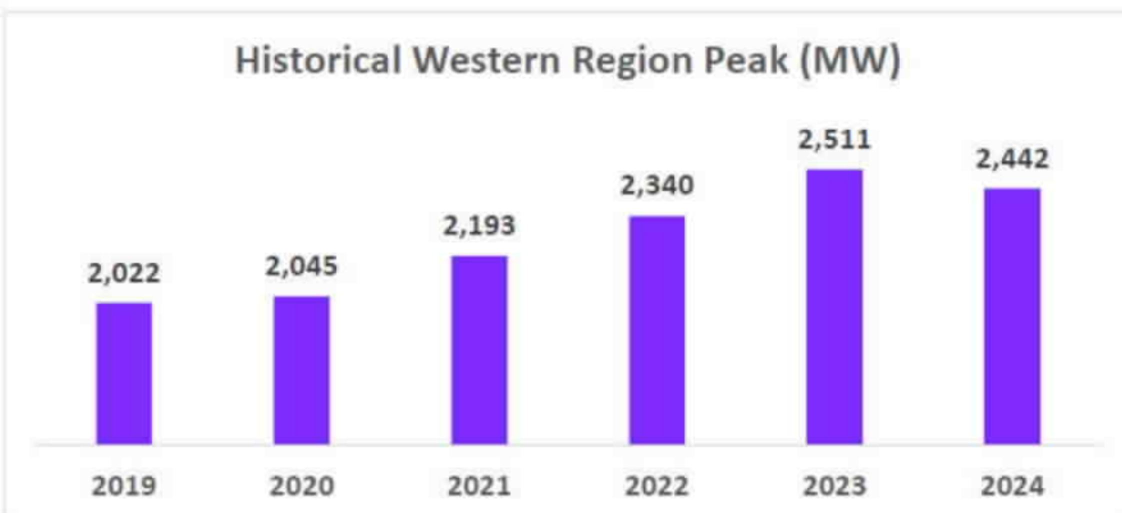
[50] ETI Ex. 15 (Peeples Dir.) at 5-6.

[51] ETI Ex. 15 (Peeples Dir.) at 21.

[52] ETI Ex. 15 (Peeples Dir.) at 5–6, 21; ETI Ex. 28 (Peeples Reb.) at 12.

In addition to industrial growth in the Eastern Region, ETI is also experiencing—and expects to continue experiencing—rapid residential growth, especially in its Western Region. From 2010 to 2023, ETI's residential customer base grew at an average annual rate of 1.7%, nearly double the national average during the same period. Data from the World Population Review confirms that 10 of the 27 counties in ETI's service territory ranked in the top quartile of growth among Texas counties. Notably, two of the fastest-growing counties in the United States are within ETI's Western Region. Figure 3 illustrates that the Western Region's peak demand has increased by over 20% since 2019, reflecting a CAGR of 4.0% from 2019 to 2024.[53]

Figure 3
Historical Western Region Peaks



ETI forecasts continued residential growth at an average annual rate of 1.7% from 2023 through 2030. Particularly rapid growth is expected in the cities of New Caney, Cleveland, and Conroe, located in Montgomery and Liberty counties—

[53] ETI Ex. 4 at (Weaver Dir.) at 13–14; ETI Ex. 26 (Weaver Reb.) at 11–12.

counties that rank among the ten fastest-growing in the nation according to the Texas Demographic Center's 2022 study. This growth is substantiated by numerous development announcements from both public and private entities.[54]

ETI anticipates that energy requirements in the Western Region will grow by 24%, with peak demand increasing by 20% (1.8% 10-year CAGR), further underscoring the pressing need for additional dispatchable capacity to support ongoing residential and economic expansion in ETI's service territory.

B. CONSIDERATION OF ALTERNATIVES

TIEC, OPUC, and Staff contend that ETI failed to demonstrate that the Dispatchable Portfolio is a cost-effective alternative to meet the additional need for service. ETI disagrees. The ALJs begin by describing the process ETI used to select the Dispatchable Portfolio, followed by a discussion of the parties' positions and the ALJs' analysis.

1. ETI's Process for Selecting the Dispatchable Portfolio

The immediacy of ETI's need for additional capacity impacted the process it used to select the resources to fulfill that need. ETI witness Abigail Weaver testified that the expected lead time to construct new generation is roughly seven years for a CT and 7.5 years for a 1x1 CCCT.[55] Thus, once the full extent of ETI's capacity need

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[54] ETI Ex. 10 (John Dir.) at 15; ETI Ex. 26 (Weaver Reb.) at 11-13.

[55] ETI Ex. 26 (Weaver Reb.) at 6-7 & Exh. ABW-R-1.

was known in the first quarter of 2023, the typical timeline would have led to in-service dates for those resources in 2030. However, ETI's forecast showed a sizeable capacity deficit as early as 2028, and thus, ETI maintains that it needed to expedite the process, including forgoing an all-source RFP.[56]

ETI explains that it decided in early 2023 to initiate project development efforts for the Dispatchable Portfolio, even before completing the analyses discussed below, "because it was apparent that dispatchable generation would be required to address ETI's need for additional capacity and its need to address emerging locational needs in the Eastern and Western Regions."[57]

a) ETI's Strategic Resource Plan

In early 2023, ETI began developing a Strategic Resource Plan (SRP) to supplement its existing resource planning process. The SRP is designed to inform ETI's management of the types of future generation resources to consider and when to start making decisions regarding the procurement of resources.[58] ETI witness Daniel Boratko explained that the SRP is much like an integrated resource plan in that it yields holistic resource planning perspectives based on a broad spectrum of planning assumptions, but the SRP is internal to ETI rather than being part of a formal regulatory process.[59]

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[56] ETI Initial Brief at 25; ETI Ex. 26 (Weaver Reb.) at 6-7.

[57] ETI Initial Brief at 23-24; ETI Ex. 4 (Weaver Dir.) at 20.

[58] ETI Initial Brief at 56; ETI Ex. 9 (Boratko Dir.) at 5.

[59] ETI Ex. 9 (Boratko Dir.) at 5.

ETI's 2023 SRP used AURORA Energy Forecasting Software to perform modeling to determine ETI's optimal long-term resource portfolio under varying future conditions, including fuel prices, available generation technologies, environmental constraints, and future demand forecasts.[60] To identify the generation resource options to include in the model, ETI used Entergy Services, LLC's (ESL)[61] existing Generation Technology Assessment, which identifies a range of supply-side resources that it believes merit more detailed analysis due to their potential to meet the planning objectives of the Entergy Operating Companies.[62] The assessment includes more than 30 potential supply-side resources, which are then screened down based on different factors to arrive at the options to input into the model.[63] ETI's SRP evaluated several options, but did not model a 2x1 CCCT or F-Class CTs.[64]

ETI evaluated five scenarios in the 2023 SRP to explore how different load growth and commodity pricing assumptions would affect the optimal mix and timing of resource additions:[65]

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[60] ETI Ex. 9 (Boratko Dir.) at 7.

[61] ESL is an affiliate of the Entergy Operating Companies that provides engineering, planning, accounting, legal, technical, regulatory, and other administrative support services to each of the Entergy Operating Companies. The Entergy Operating Companies are ETI; Entergy Louisiana, LLC; Entergy Mississippi, LLC; Entergy Arkansas, LLC; and Entergy New Orleans, LLC.

[62] ETI Ex. 9 (Boratko Dir.) at 9.

[63] ETI Ex. 9 (Boratko Dir.) at 9; Tr. Vol. 1 at 190.

[64] ETI Ex. 9 (Boratko Dir.) at 11-12; Tr. Vol. 1 at 182-83 (Boratko Cross).

[65] ETI Ex. 9 (Boratko Dir.), Exh. DCB-1 (2023 SRP) at 16.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Description	Base case	Moderate growth	Moderate low	Moderate high	Industrial load growth*
Load	BP23 load	Moderate load growth (Prelim BP24)	Moderate load growth (Prelim BP24)	Moderate Load Growth (Prelim BP24)	High industrial growth
Natural Gas Price**	Reference gas	Reference gas	Low gas	High gas	Reference gas
CO_2 Cost**	Reference CO_2	Reference CO_2	Low CO_2	High CO_2	Reference CO_2

* Nominal 2000 MW
** Reference gas is the natural gas price forecast associated with BP23
Reference CO_2 is the CO_2 price forecast associated with BP23

Three load growth paradigms were modeled. Scenario 1 used the load identified in ETI's 2023 Business Plan (BP23); Scenarios 2, 3, and 4 used a moderate load growth profile based on ETI's preliminary BP24; and Scenario 5 assumed high industrial load growth.[66] While Scenarios 1, 2, and 5 considered different loads, they used the same natural gas and carbon dioxide (CO_2) emission price assumptions. As such, they were designed to show how differences in load forecasts (such as quicker-than-expected industrial growth) impact the capacity expansion portfolios. The moderate growth scenarios (Scenarios 2, 3, and 4) used the same demand forecast, but modeled different natural gas and CO_2 pricing.[67] Thus, these scenarios tested how resource buildouts would change due to commodity pricing.

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[66] ETI Ex. 9 (Boratko Dir.) at 16-17.

[67] ETI witness Boratko explains the natural gas price forecasts and CO_2 assumptions used in the scenarios. *See* ETI Ex. 9 (Boratko Dir.) at 13-15.

The modeling for each scenario produced a slightly different portfolio of resources.[68] Yet, under all five scenarios, a CCCT is recommended in the first year of the study.[69] In addition, a CT is recommended in the first year of the study in all scenarios other than Scenario 4, which included high gas and CO_2 costs.[70]

To arrive at a final recommendation, the five portfolios were subjected to production cost modeling to determine the relevant total supply cost for each portfolio.[71] "Qualitative scoring" was then applied to each portfolio to assess risk across five areas: energy market risk, reliability, executability/optionality, fuel supply diversity, and sustainability.[72] The SRP concluded that Portfolio 2 (which corresponds to Scenario 2) is the optimal resource portfolio when considering both total relevant supply cost and the qualitative risk assessment.[73] In Portfolio 2, ETI's 1.7 gigawatt winter deficit in 2027 is met with a mix of CCCTs and CTs, followed by renewable resources in the middle of the study period, and gas resources in the outer years to replace retiring legacy gas generation.[74] Based on that result, the SRP's

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[68] ETI Ex. 9 (Boratko Dir.) at 18-26.

[69] ETI Ex. 9 (Boratko Dir.) at 31.

[70] ETI Ex. 9 (Boratko Dir.) at 31.

[71] ETI Ex. 9 (Boratko Dir.) at 27-29.

[72] ETI Ex. 9 (Boratko Dir.) at 29-30.

[73] ETI Ex. 9 (Boratko Dir.) at 31

[74] ETI Ex. 9 (Boratko Dir.) at 20.

action plan recommended that ETI "develop both CCCT and CT resources expeditiously to meet the rapid and substantial load growth of Southeast Texas."[75]

b) ETI's Power Island Equipment RFP

Although the SRP analysis was not completed until November 2023,[76] ETI used its preliminary results to move forward with the Dispatchable Portfolio.[77] In mid-2023, ETI retained Sargent & Lundy to develop a "power island equipment," or PIE,[78] RFP to obtain competitive bids for the major equipment (i.e., combustion turbine, heat recovery steam generator, and steam turbine) to be used in constructing Legend and Lone Star. Sargent & Lundy reached out to and received bids from the three companies in the market capable of meeting ETI's needs, and ultimately, recommended awarding the PIE supply contract to Mitsubishi, whose bid scored highest overall and was the least expensive on a $/kilowatt (kW) basis.[79]

After the project-specific cost estimates were developed for Legend and Lone Star, ETI performed a sensitivity analysis to determine whether that change in cost assumptions would affect the SRP's conclusions, and Portfolio 2 remained the

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[75] ETI Ex. 9 (Boratko Dir.) at 31 & Exh. DCB-1 at 89.

[76] Staff Ex. 7 (ETI Responses to Staff's 2nd Set of Requests for Information (RFIs)) at 6 (noting that the SRP analysis was completed and presented to ETI management on November 16, 2023, with the final report completed in January 2024).

[77] ETI Ex. 4 (Weaver Dir.) at 20.

[78] "PIE refers to the main components of a power plant that generate the electricity, which in this case includes a combustion turbine generator, a heat recovery steam generator and a steam turbine generator. It is often referred to as an 'island' when packaged together by one supplier." ETI Ex. 8 (McHone Dir.) at 3 n.1.

[79] ETI Initial Brief at 26-28; ETI Ex. 8 (McHone Dir.) at 9, 12, 24, 26-27.

preferred portfolio.[80] Using the project-specific costs in the modeling resulted in only minor changes to the portfolio and continued to include a simple-cycle CT and a 1x1 CCCT in 2027.

Intervenors and Staff do not raise any specific objections to ETI's PIE RFP or its results, though, as discussed below, they believe a broader, comprehensive RFP should have been done.

2. Whether a Comprehensive RFP was Necessary or Feasible

a) Parties' Positions

ETI provides three reasons for not conducting a broader, all-source RFP.[81] First, ETI notes that there is no Texas law, rule, or precedent that requires a utility to procure generation through an all-source RFP (or an RFP of any kind).[82] Second, as discussed in Section IV.A above, ETI asserts that its impending need for capacity developed quickly for reasons beyond its control and did not afford sufficient time to develop and administer a broader RFP, especially given the significant recent increase in demand for turbines and the resulting supply chain constraints. Third, ETI emphasizes that it has a specific need for incremental, thermal, dispatchable generation to reliably serve customers. ETI notes that its need for renewable

[80] ETI Ex. 9 (Boratko Dir.) at 31-32.

[81] ETI Initial Brief at 30.

[82] ETI Initial Brief at 30 (citing Tr. Vol. 1 at 272-73 (Evans Cross), 295 (Gotora Cross)).

generation is being addressed through a separate renewable RFP process and certification proceeding.[83]

ETI also contends that its PIE RFP, which obtained bids from the only three manufacturers of the major plant equipment, provides reassurance that no third-party bid in a broader RFP could have resulted in lower costs to build new dispatchable resources.[84]

OPUC and Staff, however, each stress the value of conducting a comprehensive RFP. They note that ETI has, in fact, used broader RFPs in the past, including for its Montgomery County Power Station (MCPS) and Orange County Advanced Power Station (OCAPS) generation resources, indicating that ETI is aware of the benefits of the process.[85]

It is common practice, OPUC explains, for utilities to issue comprehensive RFPs when addressing the need for generation because it ensures the utility proposes the most economical resource options.[86] OPUC points out that a comprehensive RFP forces a utility's proposed self-build resource to compete with third-party resources on an equal basis, thereby forcing the utility to thoroughly evaluate the

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[83] *See Application of Entergy Texas, Inc. to Amend its Certificate of Convenience and Necessity to Construct a Portfolio of Renewable Generation Resources*, Docket No. 56865 (pending).

[84] ETI Reply Brief at 7.

[85] *See* OPUC Initial Brief at 3; Staff Reply Brief at 6-9; *see also* ETI Ex. 4 (Weaver Dir.) at 21 (indicating that ETI did not have sufficient time to develop and conduct the type of RFP for dispatchable generation previously conducted for units like MCPS and OCAPS).

[86] OPUC Initial Brief at 3.

entire range of options. The competitive process also forces the utility to be more diligent in ensuring that the estimated cost of constructing and operating any self-build projects is the lowest reasonable cost. Otherwise, the utility would run the risk that its proposed self-build projects would not be selected. OPUC argues that ETI's SRP cannot serve as a substitute for a robust and open procurement process.[87]

Similarly, Staff emphasizes that an all-source RFP might have identified lower cost alternatives for ratepayers. Staff's recommendation that ETI's application be denied is based primarily on the fact that, without such an RFP, ETI's proposal lacks sufficient comparative metrics.[88] While an RFP is not required, Staff points to Commission precedent regarding the importance of an RFP, specifically a final order in a CCN proceeding for Southwestern Electric Power Company (SWEPCO) in which the Commission denied the utility's request to add renewable generation resources and explained that:

> Texas law does not require a request-for-proposals process or regulate such processes for generation CCNs. However, request-for-proposal processes reflect what alternatives were considered. . . . ***Without a robust, open, transparent request-for-proposals process, the Commission cannot determine whether the selected facilities are necessary compared to other options.***[89]

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[87] OPUC Initial Brief at 2.

[88] Staff Initial Brief at 5.

[89] Staff Reply Brief at 7-8 (citing *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 at 3 (Aug. 24, 2023) (emphasis added)).

Staff also disagrees with ETI's foundational conclusion that insufficient time was available to conduct a comprehensive RFP.[90] Even if it would have taken 12 months as ETI claims,[91] Staff contends that, since ETI identified the need for additional capacity in mid-2023, it could have filed a CCN application in mid to late 2024, if it had acted promptly. Because an all-source RFP might have identified lower cost alternatives for ratepayers, Staff recommends that ETI's application be denied.[92]

OPUC asserts that the timing crunch ETI experienced was due to factors it should have been able to predict, if acting as a reasonably prudent operator, or that were within its control.[93] Notably, ETI's emerging need in early 2023 resulted in part from MISO's implementation of seasonal delivery periods and availability-based accreditation.[94] However, FERC approved those changes on August 31, 2022, and MISO submitted proposed revisions even earlier on November 30, 2021.[95] Thus, in OPUC's view, ETI should have been aware of the changes as early as late 2021. Moreover, OPUC witness Evan D. Evans testified that it is reasonable to expect that MISO discussed the proposed changes with ETI and other MISO members long

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[90] Staff Initial Brief at 5; Staff Reply Brief at 8.

[91] Staff Ex. 7 (ETI responses to Staff's 2nd set of RFIs) at 13 (stating that the type of RFP used for ETI's MCPS and OCAPS resources typically takes approximately 12 months to complete once notice of intent of the RFP has been issued).

[92] Staff Initial Brief at 5.

[93] OPUC Initial Brief at 3-6.

[94] *See* OPUC Ex. 3 (ETI Response to Staff RFI No. 1-2).

[95] OPUC Ex. 1 (Evans Dir.) at 19 (citing Docket Nos. ER22-495-000 and ER22-495-001, Federal Energy Regulatory Commission Order Accepting Proposed Tariff Revisions Subject to Condition at 1 (Aug. 31, 2022)).

before it submitted the changes to FERC.[96] If ETI had acted on this knowledge sooner, OPUC concludes that ETI would have had significantly more time available to conduct a comprehensive RFP.

OPUC is also not persuaded that the short timeline is driven by unexpected load growth, as such changes rarely occur overnight or without warning to utilities.[97] While ETI emphasizes that the Inflation Reduction Act stimulated development of large industrial projects, it also admits that it "coordinate[s] with customers regarding the timing and size of load additions" and was aware of projects that had been put on hold.[98] These statements suggest, according to OPUC, that ETI had both awareness and opportunity to anticipate the load growth and plan accordingly. Additionally, OPUC notes that other utilities experiencing significant load growth were able to issue comprehensive RFPs within a short timeframe, including Southwestern Public Service Company (SPS), which issued an RFP and had an application filed within eight months, and El Paso Electric Company (EPE), which issued an RFP and had an application filed within 13 months.[99]

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[96] OPUC Ex. 1 (Evans Dir.) at 24.

[97] OPUC Initial Brief at 4-5; OPUC Ex. 1 (Evans Dir.) at 21.

[98] ETI Ex. 26 (Weaver Reb.) at 9.

[99] OPUC Initial Brief at 5; OPUC Ex. 1 (Evans Dir.) at 22-23; *see 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); *Application of El Paso Electric Company to Amend its Certificate of Convenience and Necessity for a 100 MW Solar/100 MW Battery Storage Facility*, Docket No. 57501, Application (Dec. 27, 2024) (pending).

Finally, to the extent the short timeline is driven by ETI's plan to deactivate current generation resources beginning in 2025, OPUC notes that such decisions are regularly incorporated into resource planning and that, unless generation resources experience unexpected, catastrophic failure, a utility should be aware of the timing several years in advance.[100] Furthermore, Mr. Evans testified that a utility's senior management can usually delay or otherwise modify the timing of the retirement or deactivation of specific generation resources.[101] Thus, in OPUC's view, it was ETI's lack of due diligence or factors within its control that resulted in its failure to issue a comprehensive RFP, not the planned deactivations of generation.

ETI disputes that sufficient time was available for a comprehensive RFP, or that the factors driving its capacity need were known earlier or within its control.[102] ETI witness Carlos Ruiz testified that, if the timetable had slipped any further, any new resources selected out of a broader RFP would likely not have been in service until 2030 at the earliest, thus failing to meet ETI's pressing capacity need starting in 2028.[103] Moreover, securing the necessary equipment and labor for projects of the magnitude of the Dispatchable Portfolio has now become more difficult due to the increased demand for turbines and other major equipment and rising labor costs.[104] Regarding the speed with which SPS and EPE were able to conduct broader RFPs,

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[100] OPUC Initial Brief at 6.

[101] OPUC Ex. 1 (Evans Dir.) at 25-26.

[102] ETI Reply Brief at 28-35.

[103] ETI Ex. 27 (Ruiz Reb.) at 12.

[104] ETI Reply Brief at 34; ETI Ex. 27 (Ruiz Reb.) at 5.

ETI points out that those utilities were pursuing brownfield solar resources, which can be developed and analyzed much quicker than larger greenfield thermal resources.[105]

ETI also explains that it was the cumulative effect of multiple events that transpired over a relatively short period of time that affected the level and timing of its resource need.[106] It was not until the first quarter of March 2023 that the full extent of changes to MISO's resource adequacy construct were known.[107] In addition, while ETI tracks projected industrial load growth via interactions with and announcements by existing and potential customers, it could not have anticipated the effects of the Inflation Reduction Act until after customers began responding to that legal change.[108] ETI also asserts that delaying retirement dates was not available or sufficient in this case.[109] While ETI has since extended the retirement date for Roy Nelson 6 (154 MW) from 2028 to 2030, that does not address ETI's projected shortfall in 2028 of 1,500 MW for the summer and 1,600 MW for the winter. Finally, ETI's capacity need was also driven by the termination of a 225 MW PPA by a counterparty in early 2023, which ETI did not have any control over.[110]

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[105] ETI Reply Brief at 33.

[106] ETI Reply Brief at 31.

[107] ETI Reply Brief at 31-32.

[108] ETI Reply Brief at 32; ETI Ex. 15 (Peeples Dir.) at 11-14.

[109] ETI Reply Brief at 32-33; *see also* Tr. Vol. 1 at 165-66 (Weaver Cross) (conf.). This issue is addressed further in Section IV.B.3(a)(iv) below.

[110] ETI Ex. 26 (Weaver Reb.) at 6.

b) ALJs' Analysis

The Commission has explicitly acknowledged that Texas law does not require an RFP process for generation CCNs.[111] Thus, ETI's failure to conduct an RFP is not fatal to its application. Nevertheless, a utility's use of an RFP, along with oversight by an independent monitor, is often crucial in determining whether the utility adequately identified and considered alternatives. In fact, the Commission has recently denied generation CCN requests, in whole or in part, when the utility's RFP process was not robust enough.[112]

Whether ETI had sufficient time to conduct an RFP is not clear. As an initial matter, the ALJs are not persuaded by Staff that 12 months would have been sufficient for ETI to develop and complete an RFP for dispatchable resources and to submit an application to the Commission. Likewise, the faster timelines for SPS and EPE to conduct RFPs for brownfield renewable resources are not indicative that ETI could have completed an RFP for greenfield thermal resources as quickly. The ALJs also agree with ETI that some of the reasons it gives for not having sufficient time for an RFP were not foreseeable or within its control. While ETI was aware that load was growing, the Inflation Reduction Act stimulated the development of large industrial projects that had not been previously announced or had been put on hold for an unspecified period, and thus, accelerated that growth.[113] In addition, a

[111] Docket No. 53625, Order on Rehearing at 3.

[112] Docket No. 55255, Order on Rehearing at 3-4; Docket No. 53625, Order on Rehearing at 3.

[113] *See* ETI Ex. 26 (Weaver Reb.) at 9.

counterparty terminated a long-term 225 MW PPA in early 2023, after announcing the potential change in late 2022.[114]

However, other factors contributing to ETI's capacity need should not have been a surprise. In particular, ETI's resource planning should already have been accounting for the deactivation dates for existing resources. Further, while the full extent of MISO's changes could not be known until after they were put into effect, that would not have prevented ETI from being aware of what changes were likely and planning accordingly.

Nevertheless, ETI opted to proceed with the Dispatchable Portfolio without an RFP. Thus, in this proceeding, ETI must show that, even without the benefit of an RFP, it selected a cost-effective alternative.[115]

3. Potential Alternatives to the Dispatchable Portfolio

a) Parties' Positions

Although it is undisputed that ETI has a need for capacity in 2028, TIEC, OPUC, and Staff argue that such need does not give ETI a free license to construct

[114] ETI Ex. 26 (Weaver Reb.) at 6.

[115] *See* Docket No. 53625, Order on Rehearing at 3 ("Regardless of whether a request-for-proposals process is performed, it is the electric utility's burden to demonstrate that its proposed facilities are necessary—including in light of viable alternatives.").

whatever resources it wishes; rather, ETI must evaluate reasonable alternatives to meet that need.[116] In their view, ETI has failed to do so here.

TIEC emphasizes that recent Commission precedent shows that a utility's failure to adequately consider alternatives and select the most cost-effective option will result in a denial of a CCN or conditions imposed upon approval, even when the utility has demonstrated a need for capacity.[117] For instance, in Docket No. 51215, the Commission found that ETI had a need for capacity, but nevertheless denied its application for the Liberty County Solar Facility because ETI had not demonstrated that acquiring the facility was an economic alternative for meeting its capacity, energy, and resource diversity needs.[118] Similarly, in Docket No. 55255, the Commission determined that SPS had a need for capacity but had not adequately considered alternatives to the solar facilities and battery project it was proposing.[119] The Commission ultimately approved the solar facilities with conditions, but denied the battery project.[120]

With respect to ETI's consideration of alternatives, TIEC and OPUC begin by criticizing ETI for essentially predetermining that it should construct one

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[116] TIEC Initial Brief at 10; OPUC Initial Brief at 1; Staff Initial Brief at 5.

[117] TIEC Reply Brief at 5.

[118] *Application of Entergy Texas, Inc. to Amend a Certificate of Convenience and Necessity for the Acquisition of a Solar Facility in Liberty County*, Docket No. 51215, Order at COL No. 17 (Oct. 19, 2021).

[119] Docket No. 55255, Order on Rehearing at FOF No. 48 & COL No. 11.

[120] Docket No. 55255, Order on Rehearing at FOF Nos. 74-75, OP Nos. 3-12.

1x1 CCCT and one CT.[121] They assert that, despite ETI touting its SRP process, the evidence shows that ETI decided on its preferred resources before the SRP was completed.[122] This timing indicates, according to OPUC, that either ETI decided to pursue the Dispatchable Portfolio based on incomplete data, or the SRP was not the main factor used to determine the portfolio's need.[123] Moreover, TIEC and OPUC note that the SRP's analysis was limited to resource types that ETI had preselected, meaning certain technologies were never considered.[124]

TIEC identifies four options that ETI did not consider: F-Class CTs, a 2x1 CCCT, the purchase of existing resources, and extending the life of existing resources. Each of these is discussed below along with ETI's responses.

(i) F-Class CTs

First, ETI did not evaluate using F-Class CTs (as opposed to the J-Class CT selected for Lone Star);[125] that option was excluded from both the SRP and PIE RFP.[126] TIEC explains that F-Class CTs are an older technology that is smaller and

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[121] TIEC Initial Brief at 2, 11-12; OPUC Initial Brief at 2.

[122] ETI Ex. 4 (Weaver Dir.) at 20 (noting that ETI initiated project development efforts for the Dispatchable Portfolio "prior to concluding the 2023 SRP").

[123] OPUC Initial Brief at 2.

[124] TIEC Initial Brief at 2-3; OPUC Initial Brief at 2.

[125] TIEC Initial Brief at 3, 12-13.

[126] ETI Ex. 9 (Boratko Dir.) at 11, Table 2 (identifying technologies included in the SRP); Tr. Vol. 1 at 190-91 (Boratko Cross); ETI Ex. 8 (McHone Dir.) at 10 & Exh. SM-3 at 6 (noting that the PIE RFP was limited to an advanced class natural gas-fired CT).

less expensive on a per-kW basis than J-Class CTs. They also only have 10% hydrogen co-firing capability "off-the-shelf,"[127] rather than 30% for J-Class CTs.[128]

Nevertheless, TIEC notes that many utilities are continuing to build F-Class CTs at costs significantly less than what is projected for Lone Star. For instance, SWEPCO is currently seeking certification for the 450 MW Hallsville Plant (consisting of two F-Class CTs), at a cost of $446 million, or more than $300 million less than the cost of Lone Star, excluding transmission upgrades.[129] While the Hallsville Plant is a brownfield site, and thus will not require land or pipeline costs, TIEC points out that those line items are only [redacted][130] and [redacted],[131] and will not come close to making up the more than $300 million difference.[132] Other utilities are also pursuing F-Class CTs in the 2027-2028 timeframe, including Ameren and Wisconsin Electric, all of which have per-kW capital costs that are between 24% and 44% less than Lone Star.[133] Given the availability of F-Class technology and its lower cost, TIEC argues that it was incumbent on ETI to consider this option for the Lone Star site, but it did not.

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[127] TIEC Ex. 1 (Griffey Dir.), Exh. CSG-2 at 626-67.

[128] ETI Ex. 3 (Viamontes Dir.) at 12; ETI Ex. 6 (Ruiz Dir.) at 8.

[129] TIEC Ex. 1 (Griffey Dir.) at 29 (citing *Application of Southwestern Electric Power Company to Amend its Certificate of Convenience and Necessity to Construct the Hallsville Natural Gas Plant in Harrison County, Texas and Convert Welsh Power Plant Units 1 and 3 to Natural Gas*, Docket No. 57376, SWEPCO's Notification of Declassification at Attachment 1 (Feb. 18, 2025)).

[130] TIEC Ex. 1A (Griffey Dir. HSPM) at 19 (native page 28).

[131] TIEC Ex. 80 (ETI Response to TIEC RFI No. 11-1) (HSPM) at Bates 002 (line item "Fuel").

[132] TIEC Initial Brief at 12; TIEC Ex. 1 (Griffey Dir.) at 29-30.

[133] TIEC Ex. 1 (Griffey Dir.) at 51, Figure 14.

In response, ETI emphasizes that the F-Class CT is an older technology that is less efficient than a J-Class CT.[134] This distinction is important, according to ETI, because production cost modeling shows Lone Star operating with an annual capacity factor ≥ 20%. Emissions rules adopted under Section 111(b) of the Clean Air Act restrict emissions for units operating with a ≥ 20% capacity factor to 1,170 lb. CO_2/MWh-gross,[135] which ETI's production cost modeling shows an F-Class CT cannot satisfy.[136] In contrast, if Lone Star operates as a J-Class CT with a ≥ 20% capacity factor, it is expected to have emissions below 1,100 lb. CO_2/MWh-gross.[137]

ETI insists that keeping Lone Star under a 20% capacity factor—as would be required for an F-Class CT—would limit its ability to fully address ETI's reliability requirements in the Western Region, resulting in incremental costs to meet those requirements.[138] In addition, because the J-Class CT is roughly 14% more efficient than the F-Class CT, it will have a lower cost of energy. ETI witness Boratko calculated that, if the cost of energy forecasted for Lone Star increased by 14%, it would increase costs to customers by an average of roughly $2 million per year for the study period.[139]

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[134] ETI Initial Brief at 21-23; ETI Ex. 33 (Boratko Reb.) at 6-7.

[135] ETI Ex. 33 (Boratko Reb.) at 7 (citing a summary of greenhouse gas emissions standards for fossil fuel-fired electric generating units adopted by the Environmental Protection Agency under Section 111 of the Clean Air Act); *see also* ETI Ex. 8 (McHone Dir.) at 35-36.

[136] ETI Ex. 33 (Boratko Reb.) at 7.

[137] ETI Ex. 33 (Boratko Reb.) at 7.

[138] ETI Ex. 33 (Boratko Reb.) at 7; Tr. Vol. 1 at 198.

[139] ETI Ex. 33 (Boratko Reb.) at 8. This assumes F-Class CTs could produce the same energy as a J-Class CT at Lone Star.

While there have been recent indications that the Section 111(b) rule will be rolled back by the Trump Administration,[140] ETI emphasizes that Lone Star will be a long-lived asset, and prudent resource planning must ensure that resources remain viable over time and under changing policies.[141]

ETI also believes it is improper to use SWEPCO's Hallsville CTs as a point of comparison because timing differences will affect their costs.[142] SWEPCO's units appear scheduled for commercial operation in 2027, thus, given the abrupt acceleration in market escalation in recent years, they were being developed when the market was materially different and likely less expensive than for the Dispatchable Portfolio.

In response, TIEC disputes that using a J-Class CT is necessary to comply with the Section 111(b) rule.[143] As an initial matter, ETI's position is an "after-the-fact rationalization," TIEC asserts, as the Section 111(b) rule was finalized in April 2024, and ETI issued its restrictive PIE RFP nearly a year earlier.[144] Additionally, TIEC notes that it is unclear whether this restriction will even apply when Lone Star goes into service because the rule may be rolled back, as noted

[140] *See* Tr. Vol. 1 at 159-60 (Weaver Cross); Tr. Vol. 2 at 69 (Boratko Cross).

[141] ETI Reply Brief at 22.

[142] ETI Reply Brief at 39.

[143] TIEC Initial Brief at 14.

[144] *Compare* ETI Ex. 33 (Boratko Reb.) at 5 n.8 *with* ETI Ex. 4 (Weaver Dir.) at 22-23.

above.[145] Even so, the evidence also does not show, according to TIEC, that Lone Star will run at a greater than 20% capacity factor.[146] In particular, ETI witness Sean McHone testified that ETI plans to operate Lone Star as a low-load unit (i.e., at less than a 20% capacity factor).[147] To the extent that ETI's modeling shows Lone Star is projected to run at capacity factors above 20% in some years, TIEC asserts that this potential scenario will largely be addressed when the SETEX Area Reliability Project, a 150 kV transmission line pending certification, comes online in 2030.[148] ETI's production cost modeling shows Lone Star's capacity factor [redacted].[149]

Additionally, given that the projected capacity factors are [redacted], TIEC suggests that it is possible that two F-Class CTs, limited to a 20% capacity factor, would be more economic than building an expensive J-Class CT.[150] Yet, ETI did not conduct that analysis.[151]

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[145] Tr. Vol. 1 at 159-60 (Weaver Cross); Tr. Vol. 2 at 69 (Boratko Cross).

[146] TIEC Initial Brief at 14-15.

[147] ETI Ex. 8 (McHone Dir.) at 34.

[148] TIEC Initial Brief at 15.

[149] The addition of Lone Star [redacted]. TIEC Ex. 40 (ETI Response to TIEC RFI No. 23-5) (HSPM) at 6; Tr. Vol. 2 at 80 (Boratko Cross HSPM). Thus, TIEC maintains that, [redacted]

[150] TIEC Initial Brief at 15-16.

[151] TIEC Ex. 41 (ETI Response to TIEC RFI No. 23-3).

In response to ETI's contention that using an F-Class CT would result in lower fuel savings of approximately $2 million per year, TIEC notes that even accepting that estimate, and discounting the time value of money, that would only be a difference of $60 million over the expected 30-year life of Lone Star, far less than the difference in capital cost.[152] Moreover, to determine which unit was more optimal, i.e., whether the improved efficiency of the J-Class CT would overcome its significantly higher cost, would require performing production cost modeling comparing it to the F-Class CT, which ETI did not do.[153]

Finally, TIEC notes that ETI appears to have a preference for the most advanced options available, as shown by the technology considered in the SRP and the fact that the PIE RFP was limited to advanced-class turbines.[154] TIEC observes that this preference aligns with the strategy of ETI's parent company, Entergy Corporation, of investing in renewables and hydrogen- and CCS-enabled gas generation.[155] Based on an Entergy Corporation presentation to analysts in June 2024, it is apparently planning on *only* adding such resources.[156] While TIEC acknowledges that advanced-class turbines may be the right choice for ratepayers in a given situation, it believes that, given the specific factors driving the need for

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[152] TIEC Initial Brief at 13.

[153] TIEC Initial Brief at 13-14; *see also* Tr. Vol. 1 at 191-92 (Boratko Cross); Tr. Vol. 2 at 84-85 (Boratko Cross) (HSPM), 90 (Boratko Cross).

[154] TIEC Reply Brief at 10-12.

[155] *See* TIEC Ex. 8 (Entergy 2024 Edison Electric Institute Financial Conference Presentation) at 13.

[156] TIEC Ex. 1 (Griffey Dir.), Exh. CSG-2 at 577.

Lone Star (i.e., need for peaking capacity and locational reliability needs), ratepayers would have been better served by the selection of an F-Class CT.[157]

(ii) 2x1 CCCT

Next, TIEC contends that ETI did not consider meeting its capacity need with a 2x1 CCCT.[158] TIEC emphasizes that a 2x1 CCCT is more efficient than a 1x1 CCCT, with a lower cost per kW.[159] Yet, ETI did not evaluate whether placing a single 2x1 CCCT in its Eastern Region could more cost effectively meet ETI's capacity need than the combination of a single 1x1 CCCT and a CT as proposed with the Dispatchable Portfolio. Notably, based on ETI's 2025 Business Plan (BP25) Generation Technology Assessment, for generation only (i.e., without transmission costs), a 2x1 CCCT would cost $[redacted], compared to $2.183 billion for the Dispatchable Portfolio,[160] and would provide an additional 321 MW of capacity.[161]

However, ETI emphasizes that it did, in fact, consider a 2x1 CCCT; it just screened that technology out ahead of the SRP's software modeling because ETI concluded that a 2x1 CCCT was unsuitable for its current, location-specific needs.[162]

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[157] TIEC Reply Brief at 12.

[158] TIEC Initial Brief at 16-18.

[159] TIEC Ex. 1 (Griffey Dir.) at 21-22.

[160] The cost of generation only (i.e., excluding transmission) for Lone Star is $750 million and for Legend is $1.433 billion, for a combined cost of $2.183 billion. ETI Ex. 18 (Ruiz Supp. Dir.) at 16, 24.

[161] TIEC Initial Brief at 16; TIEC Ex. 1A (Griffey Dir. HSPM) at 28 (native page 39), 163 (Exh. CSG-2 at 120).

[162] ETI Reply Brief at 5, 14.

Specifically, ETI gives three reasons for not modeling a 2x1 CCCT.[163] First, ETI's generation portfolio will soon include over 2,100 MW from two 2x1 CCCTs—MCPS (already in service) and OCAPS (to be placed in service in 2026). Having those two large facilities in place, according to ETI, provides it with the flexibility to diversify its generation portfolio with smaller conventional generation resources. Second, ETI asserts that 1x1 CCCTs enhance resiliency because deployment of multiple, smaller units reduces single-point-of-failure risk. Third, ETI contends that its locational reliability requirements necessitate that incremental conventional generation be located in both its Eastern and Western Regions, which cannot be achieved with a single 2x1 CCCT.

Regarding the location issue, ETI explains that its Western Region is its own load pocket within MISO's larger WOTAB load pocket, meaning it is critically dependent on resources within the region and has a limited ability to import additional power via transmission.[164] As such, the Western Region will require incremental voltage support to maintain reliability that cannot be met by locating a single 2x1 CCCT in the *Eastern* Region, as TIEC suggests.[165] ETI stresses that, even if a 2x1 CCCT had been modeled and selected in lieu of two smaller resources, the result would have been the same—ETI would have recognized that the modeling did not account for transmission constraints or incremental voltage support needs, and

[163] ETI Initial Brief at 20-21; ETI Ex. 9 (Boratko Dir.) at 12-13.

[164] ETI Reply Brief at 16-17; *see also* ETI Initial Brief at 48-49 (describing reactive power and voltage support benefits of Lone Star), 51-56 (addressing load serving capability benefits of Lone Star).

[165] *See* ETI Ex. 5 (Kline Dir.) at 10.

would have exercised the same resource planning judgment on the back end of the process to exclude a 2x1 CCCT, rather than on the front end.[166]

While some of the Western Region's issues would be addressed by the SETEX Area Reliability Project when it comes online in 2030, ETI emphasizes that it needs both Lone Star and SETEX in that region.[167] To contend otherwise, in ETI's view, would presume that ETI does not need any headroom on its system to "grow into" its capacity and should only be allowed to build just enough system capacity to meet the load that is immediately in front of it. Moreover, even with both projects online, the headroom will be short lived as the Western Region continues to grow.

ETI also disputes that a 2x1 CCCT would be more cost effective.[168] While a 2x1 CCCT may have a lower $/kW cost than a 1x1 CCCT, the 2x1 configuration carries a larger overall project cost.[169] In particular, adding a 2x1 CCCT to ETI's Eastern Region would require transmission upgrades of $790 million that would not be required to locate the proposed Legend 1x1 CCCT in that region.[170] In addition, in its rebuttal case, ETI completed an update of 2x1 CCCT costs based on market changes observed in the broader natural gas generation market, and based on that analysis, a 2x1 CCCT delivered in 2028 would cost $[redacted] billion inclusive of direct

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[166] ETI Reply Brief at 17-18.

[167] ETI Reply Brief at 43.

[168] ETI Initial Brief at 21.

[169] ETI Ex. 26A (Weaver Reb. HSPM) at 21.

[170] ETI Reply Brief at 18-19; TIEC Ex. 44 (ETI Response to TIEC RFI No. 4-6); ETI Ex. 30 (Kline Reb.) at 5.

interconnection costs but exclusive of network upgrades.[171] Adding the $790 million in transmission upgrades, it would total $[redacted] billion.[172]

In response, TIEC begins by noting that ETI's first two reasons for not modeling a 2x1 CCCT are essentially the same—and in TIEC's view, the fact that building multiple units reduces single-point-of-failure risk is only one of several factors that should be considered when making a resource choice.[173] If it were truly the main factor, TIEC contends that ETI should not have considered building a J-Class CT at Lone Star, as two F-Class CTs would cost less, provide the same amount of capacity, and reduce single-point-of-failure risk.[174]

As to the locational requirements in the Western Region, TIEC points out that ETI's own analysis shows that Lone Star will primarily act as a bridge to provide load-serving capability in the Western Region in [redacted].[175] The SETEX Area Reliability Project is expected to come online in 2030, [redacted].[176] ETI's forecast shows that the SETEX Area Reliability Project on its own is sufficient to meet the load requirements of the Western Region until the 2034-2035 timeframe. Lone Star is projected to come

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171 ETI Initial Brief at 21; ETI Ex. 30A (Kline Reb. HSPM) at 6-7; ETI Ex. 33A (Boratko Reb. HSPM) at 6.

172 ETI Ex. 30A (Kline Reb. HSPM) at 6-7.

173 TIEC Initial Brief at 17; TIEC Ex. 1 (Griffey Dir.) at 23-24.

174 TIEC Reply Brief at 19.

175 TIEC Initial Brief at 17, 20; ETI Ex. 30A (Kline Reb. HSPM), Exh. DPK-R-2.

176 TIEC Ex. 1A (Griffey Dir. HSPM) at 24 (native page 35).

online in 2028. Thus, while Lone Star would help meet the Western Region's load requirements in 2028 and 2029, [redacted]. According to TIEC, other options are available to ETI to bridge this [redacted].

Regarding cost, TIEC contends that ETI's estimated cost for transmission upgrades of $790 million for a 2x1 CCCT is overstated.[177] This amount improperly assumes, according to TIEC, that (1) all of the transmission upgrade costs should be assigned to the hypothetical 2x1 CCCT even though the upgrade would benefit the rest of the system; and (2) building a 1x1 CCCT rather than a 2x1 CCCT would avoid all of these transmission upgrades, rather than simply deferring them for a time.

TIEC also dismisses ETI's claims regarding the updated cost of a 2x1 CCCT, noting that even if there have been recent price increases, that does not address ETI's choice to exclude 2x1 CCCTs from consideration at the outset.[178] If ETI had initially pursued a 2x1 CCCT, it would have been developed in the same timeframe as the Dispatchable Portfolio and would not have experienced the recent price increase. Furthermore, ETI witness Boratko confirmed that the updated cost was based on a 2x1 CCCT that was 1,433 MW, while the Dispatchable Portfolio is 1,207 MW, meaning the updated cost is not an apples-to-apples comparison.[179]

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[177] TIEC Initial Brief at 18; TIEC Reply Brief at 20-22.

[178] TIEC Initial Brief at 16-17; TIEC Reply Brief at 20.

[179] *See* Tr. Vol. 2 at 67-68 (Boratko Cross).

(iii) Purchase of Existing Resources

TIEC also contends that ETI did not adequately consider whether its capacity needs could be met by purchasing existing resources, whether through a long-term PPA or a resource acquisition.[180] TIEC identifies two particular resources (discussed below) that it believes should be considered. ETI, however, disagrees that those resources would delay or obviate the need for the Dispatchable Portfolio.[181]

(a) [redacted]

In April 2024, ETI issued an RFP for existing resources and received [redacted][183] TIEC contends that, [redacted][184]

TIEC explains that, because the [redacted]

[redacted] Initial Brief at 18-24; TIEC Reply Brief at 23-24.

[181] ETI Reply Brief at 6, 24.

[182] TIEC Ex. 1A (Griffey Dir. HSPM) at 31 (native page 42).

[183] ETI Ex. 26A (Weaver Reb. HSPM) at 18.

[184] TIEC Initial Brief at 19-23.

[185] ETI Ex. 26 (Weaver Reb.) at 15.

[redacted].[186] Thus, the addition of [redacted].[187] In fact, [redacted].[188] Further, ETI is already making short-term capacity purchases from the [redacted] in order to address locational issues in the Western Region.[189] ETI admitted in discovery that adding [redacted] would "delay the need date associated with the transmission constraints" in the Western Region."[190]

Yet, TIEC claims that ETI "put several thumbs on the scale" when evaluating the [redacted].[191] First, ETI imposed a 25% penalty for debt imputation even though, as TIEC witness Griffey testified, the Commission has never found that practice to be reasonable.[192] The penalty is also contrary to [redacted]

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[186] Tr. Vol. 1 at 127 (Kline Cross).

[187] Tr. Vol. 2 at 38 (Weaver Cross); ETI Ex. 26A (Weaver Reb. HSPM) at 17-18.

[188] TIEC Ex. 34 (ETI Response to TIEC RFI No. 19-3) (HSPM) at 3.

[189] TIEC Ex. 1A (Griffey Dir. HSPM) at 25 (native page 36); *see also* TIEC Ex. 1 (Griffey Dir.), Exh. CSG-2 at 145-47.

[190] TIEC Ex. 49 (ETI Response to TIEC RFI No. 24-7) (HSPM) at 2.

[191] TIEC Initial Brief at 20.

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

[redacted].[193] Without the penalty, [redacted][194] Next, TIEC contends that ETI's estimate of the energy savings of the [redacted] was inconsistent with how it modeled the energy savings of the Dispatchable Portfolio.[195] Notably, ETI projected that [redacted][196] TIEC asserts that [redacted]

TIEC further points out that [redacted][197] While it was identified for the first time in ETI's rebuttal testimony and thus may not be ripe until a future case, TIEC believes the Commission should be aware of it since it may obviate or delay the need for Lone Star.

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[193] TIEC Ex. 20 (ETI Response to TIEC RFI No. 9-4) (HSPM) at 13.

[194] ETI Ex. 29A (Nguyen Reb. HSPM) at 10, Table 3.

[195] TIEC Initial Brief at 21-22.

[196] TIEC Ex. 1A (Griffey Dir. HSPM) at 31 (native page 42).

[197] TIEC Initial Brief at 22-23 (citing ETI Ex. 26A (Weaver Reb. HSPM) at 18).

In response, ETI first points out that [redacted][198] The 2024 RFP solicited existing resources [redacted][199] As such, ETI maintains that it was reasonable to [redacted][201] Thus, according to ETI, there is simply no basis to conclude that [redacted] was a cost-effective alternative to Lone Star.

ETI also asserts that TIEC leaves the false impression that [redacted][202] While it is true that [redacted]

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[198] ETI Reply Brief at 24.

[199] ETI Ex. 26A (Weaver Reb. HSPM) at 8, 36.

[200] ETI Ex. 26A (Weaver Reb. HSPM) at 67, 70; ETI Ex. 29A (Nguyen Reb. HSPM) at 9-10.

[201] ETI Ex. 29A (Nguyen Reb. HSPM) at 21-22.

[202] ETI Reply Brief at 25-26.

[redacted] Thus, one cannot assume that [redacted]

In addition, ETI witness Weaver explained further why ETI does not consider [redacted] as a potential substitute for Lone Star.[203] [redacted] For these reasons, ETI maintains that [redacted] should not delay consideration of the instant application for approval of the Dispatchable Portfolio.

(b) [redacted]

[redacted]

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[203] Tr. Vol. 2 at 52-53, 55-56 (Weaver Cross and Redir.) (conf.).

[204] TIEC Ex. 1A (Griffey Dir. HSPM) at 32 (native page 43) & Exh. CSG-3.

[205] TIEC Ex. 18 (ETI Response to TIEC RFI No. 19-6) (HSPM) at 2.

[206] ETI Ex. 26A (Weaver Reb. HSPM) at 23.

[redacted]

[redacted]

[redacted]

207 ETI Ex. 26A (Weaver Reb. HSPM) at 23.

208 ETI Reply Brief at 24-25.

209 TIEC Ex. 49 (ETI Response to TIEC RFI No. 24-7) (HSPM).

210 TIEC Initial Brief at 23.

211 TIEC Reply Brief at 23.

[redacted]

[redacted]

(iv) Extending the Life of Existing Resources

Finally, TIEC questions whether ETI adequately considered extending the life of existing generation to meet its need for additional service.[215] ETI's initial brief states that ETI "did not consider . . . investing in existing generation facilities to extend their useful life in lieu of the Dispatchable Portfolio because ETI's growth in load requires that incremental generation be deployed in the Eastern and Western

[212] TIEC Reply Brief at 24.

[213] TIEC Initial Brief at 24.

[214] TIEC Ex. 1A (Griffey Dir. HSPM) at 32 (native page 43).

[215] TIEC Initial Brief at 11; TIEC Reply Brief at 6; Tr. at 157-58 (Weaver Cross).

Regions."[216] However, TIEC explains that the extension of an existing resource keeps that unit available longer than it otherwise would have been, and does, in fact, result in additional physical generation. The extension of existing units, TIEC argues, is often a viable alternative for meeting a short-term need for capacity. Notably, during the pendency of this case, ETI extended the deactivation date for the Roy Nelson 6 plant from 2028 to 2030.[217]

However, ETI explains that the existing generators it plans to deactivate over the next decade have been in service in the range of 45-60+ years.[218] In particular, the following planned deactivations contribute to ETI's projected need for additional capacity:

Current Deactivation Assumptions (BP24)

Resource	Summer Installed Capacity MW	Deactivation Date
Big Cajun 2 Unit 3	81.7	2025
Sabine 1, 3 and 4	1,060.3	2026
Roy Nelson 6	154.0	2030
Lewis Creek	500.0	2034

ETI elaborates on each resource deactivation, noting first that it recently extended Roy Nelson 6's deactivation date from 2028 to 2030, but that its 154 MW

[216] ETI Initial Brief at 18, 30.

[217] *Compare* ETI Ex. 4 (Weaver Dir.) at 12, Table 12 (showing 2028 deactivation date for Roy Nelson 6) *with* ETI Initial Brief at 18, Table 1 (showing 2030 deactivation date) *and* ETI Ex. 26A (Weaver Reb. HSPM), Exh. ABW-R-6 (HSPM).

[218] ETI Initial Brief at 18.

cannot address the shortfall projected in 2028 of 1,500 MW for the summer and 1,600 MW for the winter.[219] The deactivation dates for Sabine 1, 3, and 4 cannot be extended because those units must come offline in 2026 so that transmission service may transfer to OCAPS.[220] With respect to Big Cajun 2 Unit 3, ETI does not control that resource, and furthermore, it has a smaller amount of capacity than Roy Nelson 6.[221] Finally, the resource need materializes well before the current deactivation date assumed for Lewis Creek such that any extension for that plant cannot affect the timing of the need in 2028.

b) ALJs' Analysis

The evidence shows that ETI predetermined in early 2023 that it would construct one 1x1 CCCT and one CT, both with advanced-class turbines that had 30% hydrogen co-firing capability. ETI acknowledges that it began planning for these resources *before* initiating the SRP and initiated the PIE RFP *before* completing the SRP.[222] Also, as discussed in the prior section, ETI did not conduct a comprehensive RFP. This lack of process to identify and compare resources is quite concerning, particularly when looking at resources estimated to cost $2.4 billion. Yet, even so,

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[219] ETI Reply Brief at 32-33; Tr. Vol. 1 at 165-66 (Weaver Cross).

[220] Tr. Vol. 1 at 166 (Weaver Cross).

[221] Tr. Vol. 1 at 166 (Weaver Cross); ETI Ex. 4 (Weaver Dir.) at 12.

[222] *See* ETI Ex. 4 (Weaver Dir.) at 20 (ETI initiated project development efforts for the Dispatchable Portfolio "prior to concluding the 2023 SRP"), 22 (ETI contracted with Sargent & Lundy to develop the PIE RFP in June 2023); Staff Ex. 7 (ETI responses to Staff's 2nd set of RFIs) at 6 (SRP analysis was completed and presented to ETI management on November 16, 2023).

ETI could still show that, in hindsight, its subsequent analyses support its initial selection.

However, TIEC presents compelling evidence that potentially viable options were available at a lower cost, most notably, the F-Class CT. Regarding that option, ETI did not adequately explain why it excluded an F-Class CT from consideration at the outset. Its primary arguments against that technology relate to the Section 111(b) emissions rule, which was adopted *after* ETI had already decided not to include that technology in the SRP or PIE RFP. Regarding the potential repeal of the rule, the ALJs agree with ETI that it cannot plan for long-lived assets by presuming that the rule will be rolled back, or that a similar rule will not apply at some point in the asset's lifetime. Nevertheless, ETI did not show that, based on how it plans to operate Lone Star, an F-Class CT could not satisfy the emissions rule. ETI witness McHone testified that ETI plans to operate Lone Star as a "low load CT unit," meaning that it would have an annual capacity factor of less than 20%, and thus would be below the threshold for the more stringent emissions requirements.[223] ETI attempts to explain this statement away by saying that Mr. McHone was "addressing generally the distinction in operating characteristics between combined-cycle and simple-cycle CTs relative to current emissions standards."[224] However, Mr. McHone's statement is specific to Lone Star and also refers to ETI witness Ruiz's testimony that the plant will be operated as a peaking unit.

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[223] ETI Ex. 8 (McHone Dir.) at 36 ("As explained by ETI witness Carlos Ruiz, ETI plans to operate Lone Star, which is a peaking unit, within the Phase 1 requirements applicable to Low Load CT Units, and there are no separate Phase 2 requirements for such units. Lone Star will be capable of meeting the Phase 1 requirements without utilizing CCS technology.").

[224] ETI Reply Brief at 22.

The evidence also shows that F-Class CTs are still being built and at a much lower cost than the J-Class CT proposed for Lone Star.[225] The magnitude of the cost difference appears to more than offset the potential fuel savings of operating the more efficient J-Class CT. Using two F-Class CTs at the Lone Star site would seem to meet ETI's needs because it would provide the same MW amount at the same location. Also, having two units would have the benefit of reducing single-point-of-failure risk, which ETI identified as an important consideration in selecting the Dispatchable Portfolio. Yet, as TIEC points out, ETI did not do the analysis that would have shown which option was optimal—one J-Class CT or two F-Class CTs—when considering their differing cost and operational characteristics.[226] And, thus, ETI has not demonstrated that Lone Star's one J-Class CT is more cost effective than two F-Class CTs.

Regarding a 2x1 CCCT, the primary disagreements relate to whether that technology would be more cost effective than the Dispatchable Portfolio and whether it would meet ETI's locational needs. Regarding cost, the evidence in this case tends to show that a 2x1 CCCT would cost less and provide more capacity than the Dispatchable Portfolio.[227] To the extent that more certain cost information is not

[225] *Compare* TIEC Ex. 1 (Griffey Dir.) (testifying that SWEPCO is building two F-Class CTs with total nominal capacity of 450 MW for $446 million) ***with*** ETI Ex. 18 (Ruiz Supp. Dir.) at 24 (testifying that Lone Star, which is one J-Class CT with a nominal capacity of 453 MW, is estimated to cost $750 million, when excluding transmission costs).

[226] *See* TIEC Ex. 41 (ETI Response to TIEC RFI No. 23-3) ("[ETI] determined that the J-Class [CT] is the appropriate technology for Lone Star Power Station; therefore, it did not analyze replacing that technology with two F-Class CTs.").

[227] In fact, TIEC witness Charles Griffey testified that the amount of capacity that could be provided by a 2x1 CCCT (1,440 MW) would be an alternative to not only Legend and Lone Star but also ETI's proposed Renewable Portfolio being considered in Docket No. 56865 and other capacity that ETI plans by the 2028 timeframe. TIEC Ex. 1 (Griffey Dir.) at 30, 39.

available, that is due to ETI's choice not to conduct performance cost modeling on a 2x1 CCCT. While ETI identified recent cost increases for that technology, ETI could potentially have avoided those increases if it had secured a 2x1 CCCT at the time it instead selected the Dispatchable Portfolio. In addition, although ETI estimates that locating a 2x1 CCCT in the Eastern Region would require an additional $790 million in transmission upgrades, the ALJs find it improper to attribute the entirety of that cost to a 2x1 CCCT for the reasons identified by TIEC.[228]

The ALJs, however, find ETI's arguments regarding its locational needs more persuasive. ETI witness Daniel Kline credibly explained how the Western Region's rapid load growth and being a load pocket within MISO's broader WOTAB load pocket have resulted in transmission constraints.[229] He also testified that the preferable location for a new resource is in close proximity to the load it serves and that siting generation within a load pocket is preferable if one exists.[230] While the SETEX Area Reliability Project will increase load-serving capability in the Western Region significantly, it will not come online until 2030, and as ETI points out, it is not unreasonable to have some "headroom" when choosing capacity options.

Nevertheless, because ETI excluded a 2x1 CCCT from its analyses and predetermined that it needed a CT in the Western Region, there is little evidence in

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[228] *See* TIEC Initial Brief at 18; TIEC Ex. 1 (Griffey Dir.) at 30-32.

[229] ETI Ex. 5 (Kline Dir.) at 33-34, 37-38.

[230] ETI Ex. 5 (Kline Dir.) at 7.

the record evaluating whether the cost (and added capacity) of a 2x1 CCCT plus a different option for the Western Region would be more cost-effective. Thus, on balance, the ALJs conclude that ETI did not demonstrate that excluding consideration of the 2x1 CCCT from the outset of its planning process was appropriate, nor that the Dispatchable Portfolio is a more cost-effective alternative than a 2x1 CCGT, with transmission upgrades.

As to the purchase of existing resources, the options that TIEC presents did not arise until relatively recently. The [redacted] was not received until April 2024 (just two months before this case was filed), and the [redacted] did not develop until ETI filed its rebuttal case. There is some indication that these options could obviate or delay the need for Lone Star, particularly given that [redacted], but the record is not sufficiently developed in this case to make that determination. ETI's analysis of the [redacted] showed that it was uneconomic even when imputing zero debt, and ETI's conclusion is supported by [redacted] However, ETI did not evaluate the economics of choosing [redacted] in lieu of Lone Star, and thus, it was not shown as uneconomic in that scenario. Ultimately, ETI did not show that its decision from the outset not to consider purchases of existing resources was reasonable. As such, ETI has not shown that the Dispatchable Portfolio is cost-effective compared to such resources.

Finally, regarding the planned retirement of existing resources, the ALJs find that ETI adequately explained why, beyond the relatively minor extension of the Roy Nelson 6 unit from 2028 to 2030 that ETI made, extending the service lives of existing resources was not an option to meet its identified capacity need and therefore not considered.[231]

Based on the findings above, the remaining question is whether the proposed Lone Star CT is a cost-effective option to meet ETI's needs in the Western Region. This topic is one where it would have been helpful to have a comprehensive RFP to identify a range of available options, or even for ETI to have considered a broader range of options in its SRP. As discussed, there is some evidence in this case that other options were available, including the construction of two F-Class CTs in lieu of the J-Class CT proposed for Lone Star or the purchase of existing resources, which could, either alone or in conjunction with the SETEX project, meet the near-term needs that Lone Star's CT would serve. Ultimately, it is ETI's burden to show that its proposed resources are necessary to serve the public. Based on the evidentiary record in this case, the ALJs cannot say that ETI has shown Lone Star to be a cost-effective option to meet the needs in its Western Region compared to alternatives.

[231] *See* ETI Reply Brief at 32-33; Tr. Vol. 1 at 165-66 (Weaver Cross).

4. Cost of Dispatchable Portfolio Compared to Similar Technology

In the immediately preceding section, the cost of the Dispatchable Portfolio compared to alternative technologies like an F-Class CT or 2x1 CCCT is addressed. However, TIEC also argues that the Dispatchable Portfolio is expensive compared to the cost of the same technology, i.e., a J-Class CT and 1x1 CCCT. Those arguments are addressed here.

a) Parties' Positions

TIEC maintains that, in addition to being costlier than an F-Class CT or 2x1 CCCT as discussed above, Legend and Lone Star are more expensive than other plants of their type.[232] For instance, the cost estimates for those projects are significantly higher than the Energy Information Administration's (EIA) estimates for a generic 1x1 CCCT and CT, even adjusted for market escalation.[233] TIEC witness Charles Griffey testified that, since the EIA reports the costs as overnight costs (i.e., excluding financing costs), he adjusted the EIA's as-published costs to add AFUDC.[234] He also included a [redacted] adder to reflect the market escalation between EIA's estimates for a 2x1 CCCT and the actual cost of OCAPS, plus an additional [redacted] adder based on the market escalation between ETI's BP24 and

[232] TIEC Initial Brief at 24-27.

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

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

BP25.[235] These results showed that Legend and Lone Star combined exceeded the adjusted EIA costs by [redacted][236]

In addition, TIEC claims that Legend and Lone Star are expensive compared to plants being built by other utilities around the same timeframe. For instance, Arkansas Electric Cooperative Corporation (AECC) recently announced two J-Class CTs, totaling 900 MW, with a commercial operation date in 2029, for a cost of $840 million, or $889/kW.[237] Additionally, Evergy has announced two J-Class 1x1 CCCTs, totaling 1,410 MW, at a cost of over $2 billion, which comes out to greater than $1,418/kW.[238] In comparison, the cost of Lone Star is $1,656/kW, and the cost of Legend is $1,900/kW. Notably, the EIA reports that Texas is the least costly place to build a gas turbine and that the cost of building in Kansas (where Evergy is located) is 5% higher.[239]

ETI, however, criticizes TIEC's choice of cost comparisons.[240] ETI notes that the EIA estimates are based on similar planned projects at non-specific locations, while the Legend and Lone Star estimates come from firm bid costs that have now

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235 TIEC Ex. 1A (Griffey Dir. HSPM) at 33-35 (native pages 44-46).

236 TIEC Ex. 1A (Griffey Dir. HSPM) at 35-36 (native pages 46-47).

237 TIEC Ex. 1 (Griffey Dir.) at 51.

238 TIEC Ex. 1 (Griffey Dir.) at 51.

239 TIEC Ex. 1 (Griffey Dir.) at 52.

240 ETI Reply Brief at 36-39.

been finalized through execution of the EPC contracts.[241] Using the cost estimate classification system of the Association for the Advancement of Cost Engineering, the EIA estimates are the lowest level in terms of maturity and accuracy, with an accuracy range of -50% to +100%.[242] In contrast, the EPC pricing for the Dispatchable Portfolio is the highest level of maturity and accuracy, with an accuracy range of -10% to +15%, excluding transmission costs. Given the magnitude of this difference, ETI argues that even the adjustments made by Mr. Griffey cannot create an appropriate comparison.

As to the cost of other utilities' projects, ETI contends that, without details beyond the total estimated cost, it is not possible to compare the projects to the Dispatchable Portfolio.[243] In particular, there is no evidence regarding the scope of the projects, including a breakdown of the costs across different categories of materials, equipment, and labor, nor is there evidence regarding the timing of the planning and development of the projects, which ETI asserts is critical given its pressing need for capacity in 2028. Furthermore, ETI notes that the Evergy project that TIEC identifies has no publicly available cost information beyond an internet article cited by Mr. Griffey indicating that the project is "more than $2 billion."[244] Among the missing details is whether the amount includes AFUDC and

[241] ETI Ex. 27 (Ruiz Reb.) at 6, Exh. CR-R-1.

[242] ETI Ex. 27 (Ruiz Reb.) at 6-7.

[243] ETI Reply Brief at 38-39; ETI Ex. 27 (Ruiz Reb.) at 10-11.

[244] ETI Reply Brief at 37.

contingency, which is crucial since TIEC is comparing it to the cost estimate of the Dispatchable Portfolio that includes AFUDC and contingency.

For valid cost comparisons, ETI points to two sources: a check estimate performed by Black & Veatch (B&V) and a benchmarking analysis performed using data from Power Advocate.[245] ETI retained B&V to provide an independent EPC estimate as an additional check on the accuracy and reasonableness of the estimate prepared by the EPC Consortium that will construct the Dispatchable Portfolio.[246] The B&V estimate compared quantities, rates, labor hours, equipment cost, and total costs, and found that the EPC Consortium's estimate was competitive.[247] Separately, the Power Advocate data was used to evaluate two primary benchmarks: (1) Contractors General and Administrative (G&A) and Fee, and (2) EPC contingency.[248] 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.

In response, TIEC notes that, while ETI criticizes using the EIA estimates and other utility projects as cost comparisons, its critiques do not explain away the nearly 50% discrepancy between those data points and the estimates for the Dispatchable Portfolio.

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[245] ETI Reply Brief at 35-36; ETI Ex. 6 (Ruiz Dir.) at 30; ETI Ex. 27 (Ruiz Reb.) at 7-8.

[246] ETI Ex. 6 (Ruiz Dir.) at 28.

[247] ETI Ex. 6 (Ruiz Dir.) at 30.

[248] ETI Ex. 6 (Ruiz Dir.) at 30.

Furthermore, TIEC believes that the costliness of the Dispatchable Portfolio is also demonstrated by ETI's own choice of metrics.[249] Regarding the B&V check estimate, TIEC first points out that it only evaluated the EPC Consortium's cost estimate for the 1x1 CCCT; thus, it did not include the major plant equipment from Mitsubishi, AFUDC, and owner's costs, nor did it analyze the cost of Lone Star.[250] Second, B&V's estimate was [redacted] than the EPC Consortium's estimate for the cost of Legend.[251] In fact, B&V's estimates for the G&A and Fee were [redacted] than the EPC Consortium's estimates for those line items. TIEC emphasizes that these are not material or labor costs, but the cost of overhead and the profit that the consortium would make on the project. As to the Power Advocate data, the benchmarking analysis showed that the range of G&A and Fee as a percentage of total contract cost ranged from [redacted][252] The EPC Consortium's estimate was [redacted] and TIEC asserts that ETI has not demonstrated why this is reasonable.

b) ALJs' Analysis

The ALJs begin by addressing the cost estimates for AECC's and Evergy's projects. First, for the reasons ETI identifies, the ALJs give no weight to the Evergy

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[249] TIEC Initial Brief at 26.

[250] TIEC Ex. 1A (Griffey Dir. HSPM) at 36-37 (native pages 47-48).

[251] TIEC Ex. 1A (Griffey Dir. HSPM), Exh. CSG-2 at 209-10.

[252] TIEC Ex. 1A (Griffey Dir. HSPM) at 37 (native page 48).

cost estimate as a comparison. The AECC project has some key similarities to Lone Star in that it uses J-Class CTs and has a commercial operation date of 2029 (versus 2028 for Lone Star), yet the cost difference is striking, $889/kW for AECC versus $1,656/kW for Lone Star. While ETI is correct that simply knowing this information is not sufficient to know whether the projects are truly comparable, the sheer magnitude of the difference is some evidence that Lone Star is expensive compared to similar technology.

The ALJs also find TIEC's remaining cost comparisons persuasive. The difference between the estimated cost of the Dispatchable Portfolio and the EIA estimates for similar technologies, even after adjusting them upward to account for AFUDC and market escalation, are significant. ETI's criticisms of the EIA estimates go to their level of accuracy, but do not account for the magnitude of the difference. In addition, for the reasons TIEC identifies, the ALJs find that the B&V check estimate and Power Advocate data tend to show that, at least for the limited costs that they address, the Dispatchable Portfolio is expensive, not cost competitive. Accordingly, the ALJs conclude that the preponderance of the evidence shows the Dispatchable Portfolio is expensive compared to similar technology.

5. ALJs' Analysis of Whether ETI Adequately Considered Alternatives

The Commission has made clear that "a demonstration of need for additional generation is not sufficient to justify whatever solution the electric utility proposes to add generation capacity."[253] The evidence here is clear that ETI determined at the outset that it should construct one 1x1 CCCT and one CT, both with advanced-class turbines that had 30% hydrogen co-firing capability. As noted above, ETI began planning for these resources before initiating the SRP, which is the only analysis ETI presented in this proceeding that compares the Dispatchable Portfolio to alternatives.

While an RFP is not required, the Commission has previously noted the difficulty in determining whether proposed generation resources are necessary compared to other options when there has not been "a robust, open, transparent [RFP] process."[254] The lack of information in this case is further exacerbated by ETI's choice to exclude certain options from its internal analysis in the SRP. In particular, removing the options of an F-Class CT and 2x1 CCCT on the front end so that they were not included in the SRP prevents the Commission from having more robust data to evaluate those options. As such, the Commission must rely primarily on ETI's assurances, rather than the outcome of a comprehensive RFP or production cost modeling.

Regarding cost-effectiveness, the evidence tends to show that using F-Class CTs or a 2x1 CCCT would have been less costly. In addition, the Dispatchable Portfolio was shown to be expensive compared to similar technologies, i.e., J-Class CTs and a 1x1 CCCT.

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[253] Docket No. 53625, Order on Rehearing at 2.

[254] Docket No. 53625, Order on Rehearing at 3.

Accordingly, the ALJs conclude that the preponderance of the evidence shows that ETI did not adequately consider alternatives to meet its need for additional service. Likewise, ETI did not show that the Dispatchable Portfolio is a cost-effective alternative to meet such need.

C. PROBABLE LOWERING OF COST TO CONSUMERS

One of the factors that the Commission must consider under PURA § 37.056 is the probable lowering of cost to consumers.[255] As discussed below, ETI conducted an economic analysis intended to show that customers will benefit from the Dispatchable Portfolio. TIEC, however, believes ETI failed to show net benefits of the projects. Their arguments are discussed below, followed by the ALJs' analysis.

1. ETI's Economic Evaluation of the Dispatchable Portfolio

ETI conducted an economic analysis to estimate the all-in economic costs and benefits to customers of the Dispatchable Portfolio.[256] The analysis compared a "base case" comprised of ETI's existing portfolio plus Legend and Lone Star to a "change case" comprised of ETI's existing portfolio plus three generic CTs instead—with one at the same location as Lone Star and two located at the Legend

[255] PURA § 37.056(c)(4)(E). OPUC contends that ETI failed to address the probable lowering of cost to consumers because it did not conduct a comprehensive RFP. OPUC Initial Brief at 1. Those arguments are discussed in Section IV.B.2 above and not further addressed here. The remainder of this factor regarding the probable improvement of service is addressed in Section IV.D below regarding Other Factors.

[256] ETI Initial Brief at 60-62; ETI Ex. 7 (Nguyen Dir.) at 5-17; *see also* ETI Ex. 20 (Nguyen Supp. Dir.) (updating economic analysis after ETI supplemented its application).

site (in lieu of the CCCT).[257] The metrics considered in the analysis included Total Relevant Supply Cost, Total Relevant Supply Cost Savings, and Savings Breakeven Year.

The Total Relevant Supply Cost is ETI's total cost of supplying service to customers. The Total Relevant Supply Cost Savings associated with the Dispatchable Portfolio is simply the difference between ETI's Total Relevant Supply Cost under the base case and the change case. The analysis compared the cases over the Dispatchable Portfolio's assumed 30-year life and found that the projects are expected to yield $280.8 million (2024$) in benefits, on a net present value (NPV) basis, over and above their cost, under reference case assumptions.[258] The projected net benefits come in the form of variable supply cost savings, which are made up of lower locational marginal prices paid by ETI customers to serve load and energy margins earned by ETI's generation, including the added generation.

From a customer commitment breakeven perspective, the Dispatchable Portfolio requires approximately the same upfront capital compared to three CTs and breaks even within year 1, which, according to ETI, indicates low customer risk associated with the Dispatchable Portfolio.[259]

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[257] ETI Ex. 7 (Nguyen Dir.) at 7.

[258] ETI Ex. 20 (Nguyen Supp. Dir.) at 7.

[259] ETI Initial Brief at 61.

The economic evaluation also included a sensitivity analysis considering reference, low, and high gas/CO_2 price cases, which resulted in the following estimated net benefits:[260]

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

According to ETI, these results show that, across a range of reasonable commodity market assumptions, the Dispatchable Portfolio is expected to provide significant savings to ETI's customers.[261]

In addition to its economic analysis, ETI also estimated the first-year revenue requirement for the Dispatchable Portfolio and the impact on customer bills. The first-year revenue requirement is estimated to be $305.1 million, excluding fuel recovery offsets that are estimated at $41.4 million, resulting in a total net revenue requirement for the first year of $263.7 million.[262] The estimated net impact of the

[260] ETI Ex. 20 (Nguyen Supp. Dir.) at 8.

[261] ETI Initial Brief at 62.

[262] ETI Ex. 20 (Nguyen Supp. Dir.) at 8; ETI Ex. 22 (Barrilleaux Supp. Dir.) at 5-7.

Dispatchable Portfolio on a residential customer bill using 1,000 kilowatt-hours per month is approximately $21.48.[263] This includes a base rate increase of $23.06 per month, offset by fuel costs savings of $1.58 per month. However, ETI expects that these bill impacts will be mitigated by the substantial load growth ETI is experiencing.

2. TIEC's Position

TIEC contends that the Dispatchable Portfolio will not result in the probable lowering of costs to consumers.[264] The plants would have a significant impact on base rates,[265] and ETI does not contend that the fuel savings would come close to offsetting that base-rate impact.[266] Thus, customers' rates would increase.

ETI's economic evaluation does not show otherwise, TIEC argues.[267] While the analysis purports to show net benefits, it does not compare the Dispatchable Portfolio to any real, viable alternative. Instead, it compares Legend and Lone Star to a hypothetical three-CT alternative. And, because Lone Star is also a CT, it was in essence compared to nothing. As such, TIEC contends the comparison is in actuality between Legend and two hypothetical CTs and provides no basis for

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[263] ETI Ex. 22 (Barrilleaux Supp. Dir.) at 7-8.

[264] TIEC Initial Brief at 29.

[265] TIEC Ex. 1 (Griffey Dir.) at 13 (noting that the first-year base revenue requirement for the two facilities would be $305 million, which equates to a base rate increase of 25%).

[266] TIEC Initial Brief at 29 (citing ETI Ex. 35A (Barrilleaux Reb. HSPM) at 5).

[267] TIEC Initial Brief at 29-30.

certificating Lone Star.[268] Moreover, no party is proposing that ETI should build three expensive CTs in place of the Dispatchable Portfolio to meet its capacity need.

TIEC also contends that ETI's economic analysis contains flaws that result in the projected fuel savings being inflated.[269] First, ETI compares 2028 fuel savings to its current fuel factor, meaning there is a timing mismatch in the data.[270] Second, [redacted] which are not savings compared to ETI's existing fuel factor.[271] Lastly, ETI makes [redacted] which according to TIEC, unjustifiably increases the claimed fuel savings.[272]

3. ETI's Rebuttal

In response, ETI first argues that TIEC is using the wrong metric by suggesting that fuel costs savings should wholly offset the base-rate impact of the Dispatchable Portfolio.[273] The correct metric, in ETI's view, is Total Relevant Supply Cost Savings of the Dispatchable Portfolio relative to the change case with three CTs, which is the same economic analysis framework ETI used for its MCPS

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[268] TIEC Initial Brief at 29 (citing Tr. Vol. 1 at 235 (Nguyen Cross)).

[269] TIEC Initial Brief at 29-30.

[270] TIEC Ex. 1 (Griffey Dir.) at 16.

[271] TIEC Ex. 1A (Griffey Dir. HSPM) at 10 (native page 15).

[272] TIEC Ex. 1A (Griffey Dir. HSPM) at 10 (native page 15).

[273] ETI Reply Brief at 44.

and OCAPS resources. ETI also asserts that it is inaccurate to assume that no fuel savings are shown for Lone Star just because it is being compared to an identical CT. ETI witness Phong Nguyen testified that the Dispatchable Portfolio will have a different commitment and dispatch than the three CT case, giving rise to fuel cost savings attributable to both Legend and Lone Star.[274]

ETI also disputes that its analysis is flawed.[275] In response to TIEC's contention that ETI should not have included fuel demand charges in the fuel savings calculation, ETI notes that it has already arranged for firm fuel supply for the Dispatchable Portfolio. In ETI's view, it is reasonable to assume the same for alternative resources if they were to stand in place of the Dispatchable Portfolio. Thus, ETI maintains that incurring a single fuel demand charge at Legend is a savings relative to incurring two fuel demand charges at the two alternative CTs that would substitute for Legend.[276]

As to the variable O&M adjustment, ETI explains that it was intended to allow for a more apt comparison and ensure that the modeling of the dispatch of Legend was not overly biased toward Legend.[277] Specifically, in running the AURORA production cost model, ETI purposely assumed a generic, consistent variable O&M rate for CCCT resources to prevent the variable O&M rate to bias the dispatch of

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[274] Tr. Vol. 1 at 237-40 (Nguyen Cross).

[275] ETI Reply Brief at 45.

[276] ETI Ex. 29 (Nguyen Reb.) at 7.

[277] ETI Reply Brief at 45.

the units. Once dispatch was determined, ETI adjusted the variable O&M cost to be consistent with the expected variable O&M rate for Legend. Absent this adjustment, ETI contends that Legend likely would have run more in the model and produced larger fuel savings. Hence, the variable O&M adjustment is a conservative assumption.

4. ALJs' Analysis

As an initial matter, the ALJs agree with ETI that, when looking at the probable lowering of costs to consumers, the analysis must include not only the base-rate impact but also consideration of any benefits, which here come in the form of variable supply cost savings. Regarding TIEC's three criticisms of how fuel savings were calculated, the ALJs find that, for the first issue—the timing mismatch of data—TIEC did not explain whether this change would make a material difference. As to the other two issues regarding fuel demand charges and variable O&M, the ALJs find that ETI witness Nguyen adequately explained why his calculations were reasonable.[278]

The bigger issue is whether comparing the Dispatchable Portfolio to three CTs is a useful comparison. Given that ETI has a need for capacity, the ALJs find it reasonable for ETI to compare the Dispatchable Portfolio to alternative, incremental resources, rather than a "do nothing" case.[279] However, as TIEC points out, no party has suggested that three CTs like those that would be used at Lone Star would

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[278] *See* ETI Ex. 29 (Nguyen Reb.) at 5.

[279] *See* ETI Ex. 29 (Nguyen Reb.) at 4.

be a viable alternative to the Dispatchable Portfolio. While ETI has used three CTs as a comparison in the past for its MCPS and OCAPS resources, ETI did not adequately explain why three CTs is the appropriate comparison in this case. Accordingly, the ALJs give little weight to ETI's conclusion that the Dispatchable Portfolio will result in net benefits to customers. Ultimately, ETI did not demonstrate that approval of its Dispatchable Portfolio will result in a probable lowering of costs to consumers.

D. OTHER CCN FACTORS

The remaining CCN factors that the Commission must consider under PURA § 37.056 are uncontested and are generally supportive of the Dispatchable Portfolio. Each factor is addressed briefly below.

Effect of granting the CCN on ETI and any electric utility serving the proximate area:[280] The Dispatchable Portfolio is expected to have a positive impact on ETI and its customers in that it will address ETI's need for additional capacity and energy and will enhance system reliability. Sam Houston and ETEC are the only other utilities that intervened in this proceeding. ETEC supports approval of the Dispatchable Portfolio, and Sam Houston did not take a position.[281] Neither utility provided evidence that it would be adversely affected by the Dispatchable Portfolio.

[280] PURA § 37.056(c)(3).

[281] As discussed in Section V.E below, Lone Star would be located within Sam Houston's singly certificated service territory, and Sam Houston requests that a condition be imposed if the Dispatchable Portfolio is approved.

Community values; recreational and park areas; and historical and aesthetic values:[282] ETI retained Power Engineers, Inc. (Power Engineers) to develop Environmental Assessments (EAs) for Legend and Lone Star. The EAs reflect that the projects will have only a minimal effect on community values, recreational and park areas, and historical and aesthetic values.[283]

Environmental integrity:[284] As part of developing the EAs, Power Engineers evaluated the potential for adverse impacts to identified natural resources and sensitive receptors for the Legend and Lone Star project sites and recommended avoidance and mitigation measures that ETI should employ.[285] Power Engineers did not identify any significant environmental issues associated with the construction or operation of Legend and Lone Star. The overall findings of the EAs were that the projects' effects on environmental receptors would result in environmental consequences that would vary in the range of negligible to moderate prior to the implementation of mitigation measures and, with the implementation of mitigation measures, the potential environmental consequences are manageable and reasonable.[286]

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[282] PURA § 37.056(c)(4)(A)-(C).

[283] ETI Ex. 12 (Halland Dir.) at 12; ETI Ex. 19 (Halland Supp. Dir.) at 7-8; *see also* ETI Initial Brief at 86-88.

[284] PURA § 37.056(c)(4)(D).

[285] ETI Ex. 12 (Halland Dir.) at 9-11.

[286] ETI Ex. 12 (Halland Dir.) at 12; ETI Ex. 19 (Halland Supp. Dir.) at 7-8.

Probable improvement of service:[287] No party disputed that the Dispatchable Portfolio would improve service to customers. ETI showed that the Dispatchable Portfolio would supply needed capacity and energy and provide reliability benefits.[288]

E. ALJs' Overall Analysis of CCN Factors

ETI contends that only one CCN factor listed in PURA § 37.056 is disputed—the probable lowering of cost to consumers.[289] However, this characterization of the parties' positions ignores the extensive evidence and briefing regarding whether ETI adequately considered alternatives to the Dispatchable Portfolio. While this issue is not expressly listed as a factor in PURA § 37.056, the Commission has made clear that it is part of determining whether the utility has shown that a CCN amendment "is necessary for the service, accommodation, convenience, or safety of the public."[290] In recent cases, the Commission has also considered this issue in evaluating the utility's need for additional service under PURA § 37.056(c)(2),[291] i.e., not just whether the utility has a generic need for additional service, but whether the proposed resources themselves are needed to provide service.

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[287] PURA § 37.056(c)(4)(E).

[288] *See* ETI Initial Brief at 42-56.

[289] ETI Reply Brief at 1-2.

[290] PURA § 37.056(a); *see also* Docket No. 53625, Order on Rehearing at 2-3 ("The selected facilities present too great of a reliability risk at too high of a capital-investment cost to be necessary without adequately considering alternatives. Therefore, the Commission finds that the selected facilities are not required by the public convenience and necessity and are not necessary for the service, accommodation, convenience, or safety of the public.").

[291] *See* Docket No. 55255, Order on Rehearing at 2-4, FOF Nos. 74-75; Docket No. 53625, Order on Rehearing at 2-3.

As discussed above, the ALJs conclude that ETI has a need for additional service, but that ETI did not show that it adequately considered alternatives to meet that need, nor that the Dispatchable Portfolio is a cost-effective alternative. Also, the ALJs give little weight to ETI's economic analysis purporting to show net benefits for the projects compared to a three-CT alternative. The remaining CCN factors are either positive (improved service and reliability), or neutral (minimal, if any, effect on other utilities; community values; recreational and park areas; historical and aesthetic values; and environmental integrity).[292]

Thus, balancing the CCN factors comes down to whether ETI's need and the probable improvement in service and reliability that the Dispatchable Portfolio would provide outweighs ETI's failure to adequately consider available alternatives and the resulting cost difference of not selecting a lower cost alternative. ETI notes that PURA does not rank the factors and that none is intended to prevail in all possible circumstances.[293] Given its pressing need for capacity in 2028, ETI urges the Commission to "place higher weighting on the need factor."[294] The ALJs agree that need is an important factor entitled to much weight in this case. However, the Commission has also emphasized the importance of adequately considering alternatives and being mindful of the costs that will ultimately be recovered from customers. Notably, the Commission has repeatedly denied requests for CCN

[292] The ALJs conclude that the factor under PURA § 37.056(c)(4)(F) regarding "the need for extending transmission service where existing or projected electrical loads will be underserved" does not apply here.

[293] ETI Reply Brief at 4.

[294] ETI Reply Brief at 4.

amendments when utilities have proved up need, but not the selection of a cost-effective alternative.[295]

On balance, the ALJs conclude that the need for service, even though pressing, does not outweigh the failure to show that the Dispatchable Portfolio is a cost-effective alternative to meet that need. Accordingly, the ALJs recommend that ETI's application be denied.

The ALJs acknowledge that the evidence shows that ETI has an imminent need for additional capacity as early as 2028 and that sufficient time is likely not available to secure different resources to meet that need. Therefore, the Commission may conclude that the application should nevertheless be approved. In that event, the ALJs recommend that certain conditions be imposed (as discussed below). However, the ALJs believe such an approach would be unprecedented and are concerned that it could improperly incentivize utilities to put the Commission in a bind timewise so that its options are either to deny a project despite a significant capacity need, thereby potentially harming customers, or nevertheless approve a project even if it is has not been shown to be a cost-effective alternative, thereby also potentially harming customers.

[295] Docket No. 53625, Order on Rehearing at 2-3, COL Nos. 6, 14; Docket No. 51215, Order at COL No. 17, OP No. 2; *see also* Docket No. 55255, Order on Rehearing at 2, FOF No. 75, OP No. 3 (denying CCN amendment in part).

V. Proposed Conditions

TIEC, OPUC, Sam Houston, and Staff each propose various conditions if ETI's application is approved. The Texas Parks and Wildlife Department (TPWD) also provided various recommendations for the Dispatchable Portfolio if it is approved. The proposals and the ALJs' recommendations are each discussed in turn.

A. Cost Cap and Prudence Review

TIEC, OPUC, and Staff each request that the Commission impose certain conditions regarding the capital costs for the Dispatchable Portfolio that ETI can recover from customers through rates. ETI disagrees that such conditions are appropriate or necessary. The parties' positions are discussed below, followed by the ALJs' recommendation.

1. TIEC, OPUC, and Staff's Positions

In explaining the need for its proposed cost conditions, TIEC begins by observing that ETI has put the Commission in a difficult position—ETI failed to demonstrate that it selected appropriate alternatives, but there is now insufficient time available to restart the selection process and still meet reliability needs in 2028.[296] Indeed, ETI's president, Eliecer Viamontes, confirmed at the hearing that, in his view, ETI does not have time to pursue any alternatives other than Legend and

[296] TIEC Initial Brief at 31.

Lone Star at this point.[297] Yet, TIEC emphasizes that the Commission is required to regulate ETI in the public interest and to ensure that its rates are just and reasonable.[298] Thus, in TIEC's view, ratepayers should not be liable for any costs that could have been avoided by the prudent selection of lower-cost alternatives.

To accomplish this, TIEC recommends that the Commission impose a "soft cost cap" of $1.8 billion for the plants, above which there would be no presumption that costs incurred for the Dispatchable Portfolio were prudent.[299] Based on TIEC's analysis, the cost of the Dispatchable Portfolio exceeds the cost of potential alternatives and industry benchmarks by a range of [redacted][300] The low end of this range accepts ETI's contention that a separate CT and 1x1 CCCT are needed in its Western and Eastern Regions.[301] Taking $600 million [redacted] and subtracting that from ETI's estimated cost of the Dispatchable Portfolio of approximately $2.4 billion results in the $1.8 billion cap. To obtain cost recovery above the capped amount, ETI would have to demonstrate both that it was prudent to select the plants and to spend more than $1.8 billion to construct them.[302] TIEC notes that its proposal differs from a "hard cap" (i.e., a cap that automatically disallows costs exceeding the cap) because, under

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297 Tr. Vol. 2 at 11-12 (Viamontes Cross).

298 PURA §§ 11.002(a), 36.003(a).

299 TIEC Initial Brief at 31-32; *see also* TIEC Ex. 1 (Griffey Dir.) at 53-55.

300 TIEC Initial Brief at 27-28.

301 *See* TIEC Initial Brief at 32 n.234.

302 TIEC Initial Brief at 32; TIEC Ex. 1 (Griffey Dir.) at 53.

TIEC's approach, ETI would still have the opportunity to prove that it acted prudently in selecting the Dispatchable Portfolio and to obtain full cost recovery.[303]

Alternatively, if the Commission does not wish to set a specific cap in this case, TIEC requests that the Commission specify in its order that there will be no presumption that ETI acted prudently in selecting Legend and Lone Star to meet its need.[304] Instead, ETI will retain the burden of proving in a subsequent rate case that it acted prudently in selecting the resources, and the appropriate level of cost recovery will remain to be determined in that case. Regardless of the form of the cost condition, TIEC argues that the Commission should make clear that ratepayers will not have to pay for costs that were imprudently incurred based on ETI's selection of Legend and Lone Star compared to alternatives.

TIEC stresses that its proposed cost condition is an alternative to the Commission simply denying ETI's application, which would be the ordinary result when a utility fails to meet its burden of proof in a CCN case. Thus, under TIEC's proposal, ETI would essentially be given a second "bite at the apple" to prove that the Dispatchable Portfolio constituted the "most cost-effective alternative" to meet its needs when it made that selection. In TIEC's view, this approach simultaneously ensures that reliability needs in 2028 are met, while also protecting customers from imprudent costs that could have been avoided by selecting less costly alternatives.

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303 TIEC Reply Brief at 28-29.

304 TIEC Initial Brief at 32.

OPUC agrees that cost conditions are needed and makes two proposals. First, because ETI has not demonstrated that the Dispatchable Portfolio is the most economical choice to meet its capacity need, OPUC requests, similar to TIEC, that the Commission explicitly state that it is not making any determination as to the reasonableness or prudence of the estimated costs for the projects.[305] This condition is justified, according to OPUC, due to ETI's failure to conduct a comprehensive RFP and other shortfalls in the process.

Second, OPUC requests that the Commission establish maximum cost caps for Legend and Lone Star equal to the modified estimated costs for each project.[306] OPUC argues that the cost caps are necessary because ETI's estimated costs for the Dispatchable Portfolio remain in doubt. While ETI indicated in its supplemental filing that certainty around the estimated costs had increased, it did not decrease the contingency costs accordingly.[307] This suggests, in OPUC's view, that ETI is not confident that its actual costs will be close to the estimates. OPUC notes that the Commission has previously implemented cost caps to protect customers when the actual costs were at risk of significantly exceeding estimated costs.[308]

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[305] OPUC Initial Brief at 7-8.

[306] OPUC Initial Brief at 8; OPUC Reply Brief at 6-7.

[307] ETI Ex. 18 (Ruiz Supp. Dir.) at 16-17, 24; Tr. Vol. 1 at 229 (Ruiz Cross).

[308] *See* OPUC Ex. 1 (Evans Dir.) at 32 (citing Docket No. 55255, Order on Rehearing at 4-5, FOF Nos. 130-130C; *Application of Southwestern Public Service Company for Approval of Transactions with ESI Energy LLC, and Invenergy Wind Development North America LLC, to Amend a Certificate of Convenience and Necessity for Wind Generation Projects and Associated Facilities in Hale County, Texas and Roosevelt County, New Mexico, and for Related Approvals*, Docket No. 46936, Order at FOF No. 71 (May 25, 2018)).

Finally, Staff offers a different approach to addressing the cost issue. Staff requests that, if the actual cost to construct the Dispatchable Portfolio, inclusive of AFUDC, exceeds the total $2.401 billion estimated cost for the two projects by more than 10%, then Staff, in consultation with ETI, should be allowed to develop an RFP and select a third-party consultant to conduct a prudence review, at ETI's cost.[309] Staff would have final approval on selecting the consultant and would promptly notify ETI of the budgeted cost before the consultant's work began. The purpose of the 10% trigger is to protect ratepayers from excessive and imprudent cost overruns.[310] It is appropriate for ETI to pay for the consultant, in Staff's view, because recovering the cost from ratepayers would be punitive, especially since they would also be paying for any prudent cost overruns. Staff notes that a similar condition was imposed in SPS's recent CCN case in Docket No. 55255.[311]

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[309] Staff Initial Brief at 3, 5-6; Staff Reply Brief at 3, 5-6. After reply briefs were filed, ETI filed on May 7, 2025, a motion for conditional leave to respond to Staff's reply brief, along with ETI's conditional response. The motion states that Staff appears to be recommending for the first time in its reply brief that a "hard cost cap" be imposed on the Dispatchable Portfolio. ETI notes that Staff witness Sherryhan Ghanem's testimony was ambiguous on this issue, so ETI asked a question in discovery about whether she was proposing a hard cost cap. In her response, she did not indicate that she was recommending one. On May 12, 2025, Staff filed a response to ETI's motion in which it stated that it is *not* recommending a hard cost cap. The ALJs agree with ETI that Staff's briefing presents ambiguity about whether it is recommending a hard cost cap. Accordingly, ETI's motion for conditional leave to respond is **GRANTED**, and the ALJs have considered ETI's response to ensure that the parties' positions are accurately captured. For the same reason, the ALJs find it appropriate to also consider Staff's subsequent response to the extent that it addresses the cost cap issue.

[310] Staff Reply Brief at 6.

[311] Docket No. 55255, Order on Rehearing at 4-5, FOF Nos. 130A-130C, OP Nos. 4-8.

2. ETI's Position

ETI contends that imposing conditions regarding cost caps and a third-party consultant is unwarranted.[312] Regarding cost caps, ETI notes that, in its most recent CCN proceeding for OCAPS, the Commission stated that "it is not the Commission's customary practice to impose cost caps in CCN proceedings."[313] In that case, the Commission was "concerned that setting too low of a cost cap might prompt [ETI] not to build [OCAPS]," due to significantly higher inflation than had been experienced in the recent past.[314] The Commission explained that a cost cap was not needed to protect customers from unreasonably high costs because other effective measures were already in place, namely, ETI would be required to prove the reasonableness and prudence of building the resource and of all actual costs incurred before any costs were included in rate base.[315] The Commission went on to explain that ETI had a continuing obligation to act as a reasonable, prudent operator of a public utility, and the Commission would review ETI's actions under that standard and the requirements of PURA and Commission rules in a future base-rate proceeding.[316]

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[312] ETI Initial Brief at 77-81; ETI Reply Brief at 54-56.

[313] ETI Initial Brief at 78 (citing *Application of Entergy Texas, Inc. to Amend its Certificate of Convenience and Necessity to Construct Orange County Advanced Power Station*, Docket No. 52487, Order at 2-3 (Jan. 12, 2023)).

[314] Docket No. 52487, Order at 3.

[315] Docket No. 52487, Order at 3.

[316] Docket No. 52487, Order at 3.

ETI notes that inflation, market escalation, and volatility are even more exacerbated now, and thus, the Commission's rationale for not imposing a cost cap for OCAPS is even more pertinent here.[317] The same customer protections also still apply. In addition, ETI reiterates that it is entitled to the opportunity to earn a return of an on the invested capital used to serve its customers,[318] which would be hindered by a cost cap that limits prudently incurred costs (as imprudent costs are already disallowed). ETI also believes that allowing the other parties to essentially relitigate whether the Dispatchable Portfolio is in the public interest improperly gives them another "bite at the apple" and is inconsistent with PURA and Commission precedent.[319] ETI emphasizes that it is proposing to make a significant investment in the Dispatchable Portfolio and needs some reasonable assurance that its choice of action will not be subject to continued litigation later.

Finally, ETI contends that Staff's third-party consultant condition is improper.[320] ETI notes that intervenors routinely hire consultants in rate proceedings to review the prudence of costs that are presented for recovery, and Staff has internal subject-matter experts who review those costs as well. In addition, ETI and other utilities already pay Commission-imposed fees to fund the Commission to conduct activities contemplated by PURA.[321] ETI also argues that

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[317] ETI Initial Brief at 78-79.

[318] *See* PURA § 36.051.

[319] ETI Initial Brief at 79.

[320] ETI Reply Brief at 54.

[321] PURA §§ 16.001-.004.

the condition is punitive, as Staff witness Sherryhan Ghanem testified that ETI should bear the cost of the consultant even if ETI exceeded the threshold, retained a consultant, and the consultant determined that the costs were prudent. Furthermore, although the Commission adopted a third-party consultant condition for SPS in Docket No. 55255, ETI notes that SPS agreed to the condition.[322] Thus, it was not imposed on SPS as a new universal condition that is now applicable to all generation CCN cases.

3. ALJs' Analysis

For the reasons discussed in Section IV.E above, the ALJs conclude that ETI failed to show that the Dispatchable Portfolio is a cost-effective alternative to meet its need for additional service, which would typically warrant denial of ETI's application. However, if the Commission concludes that the application should nevertheless be approved given ETI's imminent need for capacity and limited time to secure it, the ALJs believe that conditions regarding ETI's cost recovery should be imposed to insulate its customers from higher costs potentially resulting from ETI not considering viable, lower cost alternatives. The question then is what condition(s) to adopt.

The ALJs are mindful that the Commission has indicated that applying a cost cap in a CCN proceeding is not its customary practice and depends on the facts of a given proceeding.[323] In the limited instances in which the Commission has imposed

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[322] Docket No. 55255, Proposal for Decision at 50 (May 20, 2024).

[323] Docket No. 52487, Order at 2-3.

a cost cap, there have been exceptional circumstances.[324] Furthermore, utilities are generally entitled to recover their prudent, reasonable, and necessary costs.[325]

Before addressing what conditions to apply in a future case concerning ETI's recovery of its Dispatchable Portfolio costs, the ALJs believe it is worth noting what the prudence standard in that case would entail. The Commission has concluded that:

> The standard for determining prudence is the exercise of that judgment or the choosing of one of a select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives available at the point in time such judgment is exercised or option chosen.[326]

No party has pointed to precedent where a utility enjoys a presumption that its selection of resources is prudent simply because the utility received Commission approval to include the resources in its CCN. In fact, such a presumption appears

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[324] *See, e.g.*, Docket No. 46936, Order at FOF No. 71; *Application of Southwestern Electric Power Company for a Certificate of Convenience and Necessity Authorization for a Coal Fired Power Plant in Arkansas*, Docket No. 33891, Order at 7 (Aug. 12, 2008) ("If the projected costs for building and operating this plant were higher, the Commission would be unlikely to find that the plant would provide the necessary benefits to consumers and would be likely to find that building the plant would place undue risks to the financial standing of the company."). While Docket No. 46936 was resolved via a settlement agreement in which the parties agreed to a cost cap, the Commission found that the agreed conditions, including the cap, were instrumental to its approval of the projects. Docket No. 46936, Order at FOF No. 64, COL No. 7.

[325] *See* PURA § 36.051.

[326] *Pub. Util. Comm'n of Tex. v. Tex. Indus. Energy Consumers*, 620 S.W.3d 418, 428 (Tex. 2021).

contrary to precedent.[327] Nevertheless, as a practical matter, the Commission's determination in a CCN case that constructing a particular resource is necessary to serve the public is an indicator that it is among the "select range of options which a reasonable utility manager would exercise or choose," and thus, prudent, at least as of the time the Commission made its decision. Thus, to the extent that the Commission approves ETI's application, it would benefit customers (and ETI itself) for the Commission to clarify what ETI must show to obtain cost recovery in a future proceeding.

Regarding the proposed costs caps, the ALJs first conclude that setting a cost cap at the full $2.4 billion estimated cost for the Dispatchable Portfolio would not adequately address the issues raised in this proceeding. In particular, setting a cap at the full amount would not protect customers from paying costs that would not have been incurred if ETI had selected a lower cost option. The ALJs also have concerns with TIEC's proposed $1.8 billion "soft cost cap," as it is based on the erroneous assumption that any portion of the Dispatchable Portfolio would be presumed prudent. As such, it also does not appear to provide any further protection beyond what is already required by the existing prudence standard set forth above.

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[327] *See Tex.-New Mexico Power Co. v. Tex. Indus. Energy Consumers*, 806 S.W.2d 230, 233 (Tex. 1991) ("The certificate of convenience and necessity affords only a right to begin construction, not a guarantee that every inefficient or imprudent expenditure will be passed on to the consuming public."); *Entergy Gulf States, Inc. v. Pub. Util. Comm'n of Texas*, 112 S.W.3d 208, 214 (Tex. App.—Austin 2003, pet. denied) ("To raise the price of its product, the utility must participate in a rate case and bear the burden of proving that each dollar of cost incurred was reasonably and prudently invested. A utility enjoys no presumption that the expenditures reflected therein have been prudently incurred by simply opening its books to inspection." (internal citation omitted)).

However, the ALJs find that it is reasonable, as TIEC and OPUC request, for the Commission to clarify that in a subsequent rate case, ETI will retain the burden of proof to show that, despite the deficiencies in the instant case, it was prudent to select Legend and Lone Star and to incur the costs to construct them.

Finally, the ALJs also recommend that the Commission adopt Staff's proposed condition regarding retaining a third-party consultant. While the ALJs agree with ETI that the Commission's decision to adopt such a condition for SPS in Docket No. 55255 was not intended to create a new "universal condition" applicable to CCN cases, it shows that such a condition may be appropriate based on the facts of a particular case. Here, as in the SPS case, the process for selecting the resources was deficient. As such, it is reasonable that, if the cost of the Dispatchable Portfolio exceeds ETI's estimate of $2.401 billion, including AFUDC, by more than 10%, ETI defrays the Commission's cost of evaluating the prudence of the projects.

B. Competitive Tariff Proceeding

TIEC advocates that the Commission adopt a condition requiring ETI to initiate a separate proceeding to update its existing Competitive Generation Service (CGS) tariff, or adopt a similar mechanism (referred to by ETI as a "sleeving tariff"), to allow ETI's customers to obtain at least a portion of their power from third-party sources.[328] The competitive tariff could take various forms, but the gist, TIEC explains, is that the customer would be able to procure power from a provider

[328] TIEC Initial Brief at 33-40; TIEC Reply Brief at 31-36.

other than ETI, with ETI providing transmission service.[329] As such, the tariff would provide an additional option to help meet ETI's growing capacity need, rather than simply building new expensive generation.

TIEC likens the concept to how utilities use load-modifying resources—such as interruptible programs—in planning to meet their capacity needs.[330] These programs can be conceptualized either as reducing load or adding a resource. Either way, they can function to help meet system capacity needs. TIEC asserts that a competitive tariff could provide these types of benefits, but that ETI has been unwilling to consider it despite its urgent need for capacity.[331] ETI's concerns about potential cost-shifting for such a tariff (discussed below) are conclusory, in TIEC's view, as no tariff has yet been proposed, so it is not possible to know the impacts.[332]

According to TIEC, a competitive tariff would benefit all ratepayers by reducing overall costs and risks. It emphasizes that ETI's ratepayers are already facing a system-average base-revenue increase of 50% just from OCAPS and the proposed Dispatchable and Renewable Portfolios,[333] and those resources represent only a portion of the approximately $4.8 billion in capital additions ETI plans to

[329] TIEC Initial Brief at 35.

[330] TIEC Initial Brief at 36.

[331] TIEC Reply Brief at 31.

[332] TIEC Initial Brief at 39.

[333] TIEC Ex. 1 (Griffey Dir.) at 15.