Filing Receipt

Received - 2022-10-27 02:32:52 PM
Control Number - 53719
ItemNumber - 257

SOAH DOCKET NO. 473-22-04394
PUC DOCKET NO. 53719

APPLICATION OF ENTERGY	**§**	**BEFORE THE STATE OFFICE**
TEXAS, INC. FOR AUTHORITY	**§**	**OF**
TO CHANGE RATES	**§**	**ADMINISTRATIVE HEARINGS**

WORKPAPERS TO THE DIRECT TESTIMONY

OF

CHARLES S. GRIFFEY

ON BEHALF OF TEXAS INDUSTRIAL ENERGY CONSUMERS

October 27, 2022

Entergy

Entergy Services, LLC
919 Congress Ave , Suite 701
Austin, TX 78701
Tel 512-487-3961
Fax 512-487-3958

Legal

2019 SEP 18 PM 1: 10

September 18, 2019

Public Utility Commission of Texas
Ana Trevino. Filing Clerk
1701 N. Congress Avenue
7th Floor
Austin. Texas 78711-3326

Re: *Application of Entergy Texas, Inc. to Revise Fixed Fuel Factor (Schedule FF) in Compliance with Order in Docket No. 32915,* PUC Docket No. 49873, SOAH Docket No. 473-19-6852

Dear Ms. Trevino,

In accordance with SOAH Order No. 2 issued in this matter on August 26, 2019, attached for filing is a clean copy of Schedule FF, to be stamped "Approved" by the Commission's Central Records Division and retained in Entergy Texas, Inc.'s tariff.

Sincerely,

Miguel Suazo
Senior Counsel
Entergy, Texas Inc.

Attachment

cc: Parties of Record

ENTERGY TEXAS, INC. Electric Service SCHEDULE FF	Sheet No.: 51 Effective Date: 8-29-19 Revision: 49 Supersedes: FF Effective 3-1-19 Schedule Consists of: One Sheet

FIXED FUEL FACTOR AND LOSS MULTIPLIERS

The Texas retail fixed fuel factor is $0.0231702 per kWh.

The loss multipliers by voltage level are:

Delivery Voltage	Loss Multiplier
Secondary	1.022189
Primary	0.996053
69kV/138kV	0.971279
230kV	0.954986

The corresponding fixed fuel factors by voltage level are:

Delivery Voltage	Fixed Fuel Factor
Secondary	$0.0236843 per kWh
Primary	$0.0230788 per kWh
69kV/138kV	$0.0225048 per kWh
230kV	$0.0221272 per kWh

PUBLIC UTILITY COMMISSION OF TEXAS
APPROVED
AUG 29 '19 DOCKET 49873
CONTROL #

PUC DOCKET NO. 51215
SOAH DOCKET NO. 473-21-0478

APPLICATION OF ENTERGY TEXAS, INC. TO AMEND A CERTIFICATE OF CONVENIENCE AND NECESSITY FOR THE ACQUISITION OF A SOLAR FACILITY IN LIBERTY COUNTY	§ § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the application of Entergy Texas, Inc. to amend its certificate of convenience and necessity for the acquisition of a solar facility in Liberty County, Texas. Entergy seeks approval to acquire the proposed 99.96-megawatt (MW) Liberty County solar facility (the proposed facility). The proposed facility would be built on approximately 1,200 acres in Liberty County. The State Office of Administrative Hearings (SOAH) filed a proposal for decision recommending denial of Entergy's application. The Commission adopts the proposal for decision and denies Entergy's application, as outlined in this Order except as described below.

The Commission modifies finding of fact 54 to correct a typographical error. The fact is stated correctly elsewhere in the proposal for decision. Also, the Commission deletes conclusions of law 6 and 10 because they are unnecessary to the Commission's decision. Finally, the Commission makes other non-substantive changes for such matters as capitalization, spelling, grammar, punctuation, style, correction of numbering, and readability.

I. Findings of Fact

The Commission adopts the following findings of fact.

Notice and Procedural History

1. On September 11, 2020, Entergy filed an application with the Commission to amend its certificate of convenience and necessity (CCN) number 30076 for approval to acquire and operate the 99.96-MW proposed facility.

2. The application did not include any transmission facilities.

3. Entergy provided notice of its application to all parties to Entergy's most recent base-rate case; the county judges in Liberty County; the mayors of the cities of Dayton, Liberty,

275

Mont Belvieu, and Old River-Winfree (the only municipalities within five miles of the proposed facility's site); utilities within five miles of the proposed facility's site; the Office of Public Utility Counsel (OPUC); directly affected landowners; and the Department of Defense Siting Clearinghouse. Entergy also provided notice and a copy of the environmental assessment to the Texas Parks and Wildlife Department. In addition, Entergy published notice once in *The Vindicator*, the newspaper of general circulation in Liberty County, within a week of the filing of its application.

4. The following parties intervened and participated in this docket: OPUC, Texas Industrial Energy Consumers (TIEC), and a group of cities served by Entergy (Cities). Cities consists of the following municipalities: Anahuac, Beaumont, Bridge City, Cleveland, Dayton, Groves, Houston, Huntsville, Liberty, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Pinehurst, Port Arthur, Port Neches, Roman Forest, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, and West Orange.

5. In Order No. 1 filed on September 21, 2020, a Commission administrative law judge (ALJ) included a protective order.

6. On October 9, 2020, Commission Staff filed a recommendation that the notice and application be found sufficient.

7. In Order No. 3 filed on October 12, 2020, a Commission ALJ found the application sufficient and materially complete and approved Entergy's text and provision of notice.

8. On October 23, 2020, the Commission referred the application to SOAH.

9. In SOAH Order No. 2 filed on October 27, 2020, the SOAH ALJs confirmed the statutory deadline is September 13, 2021 under Public Utility Regulatory Act (PURA)[1] § 37.058(d).

10. In SOAH Order No. 3 filed on October 29, 2020, the SOAH ALJs adopted the parties' agreed procedural schedule with a few minor changes.

11. On October 29, 2020, the Commission issued a briefing order.

12. On November 3, 2020, Commission Staff and Entergy filed proposed lists of issues to be addressed in the proceeding.

---

[1] Public Utility Regulatory Act, Tex. Util. Code §§ 11.001–66.016 (PURA).

13. On November 9, 2020, Commission Staff, Entergy, OPUC, and TIEC filed briefs in response to the Commission's briefing order.

14. On November 19, 2020, the Commission issued a preliminary order listing the issues to be addressed in this proceeding and identifying two issues as matters not to be addressed in this proceeding.

15. In SOAH Order No. 4 filed on March 25, 2021, the SOAH ALJs provided instructions and deadlines relating to the hearing and post-hearing briefs.

16. In SOAH Order No. 5 filed on April 19, 2021, the SOAH ALJs adopted agreed procedures, including a revised hearing start date and deadlines.

17. Collectively, the Commission's preliminary order and SOAH Order Nos. 3, 4, and 5 include a statement of the time, place, and nature of the hearing; a statement of the legal authority and jurisdiction under which the hearing is to be held; a reference to the particular sections of the statutes and rules involved; and either a short, plain statement of the factual matters asserted, or an attachment that incorporates the reference by factual matters asserted in the complaint or petition filed with the state agency.

18. The hearing on the merits convened by videoconference on April 22, 2021 and concluded on April 23, 2021. The SOAH ALJs presided, and all parties appeared through their attorneys.

19. The record closed on May 20, 2021, following the parties' filing of reply briefs and proposed findings of fact and conclusions of law.

20. Entergy classified certain information, including information in evidence, as highly sensitive protected material under the protective order. After the hearing, Entergy de-designated some of that information, which is now public.

Description of Applicant, Proposed Facility, and Proposed Transaction

21. Entergy provides fully bundled electric delivery service to approximately 460,000 customers across 27 counties in southeast Texas.

22. Entergy is authorized under CCN number 30076 to provide service to the public and to provide retail electric utility service within its certificated service area.

23. The proposed facility is a proposed 99.96-MW solar photovoltaic electric generation facility that would include solar photovoltaic modules mounted to a single-axis tracking system connected to direct-current-to-alternating-current inverter stations and a substation with a 138-kV main power transformer.

24. The proposed facility would be connected to Entergy's new switching station on its Gordon–Stilson 138-kilovolt (kV) line.

25. The proposed facility would be built in Liberty County, Texas, near the city of Dayton and sited on approximately 1,200 acres of real property that would be purchased as part of the transaction.

26. Liberty County Solar Project, LLC (the project company) would own the electricity-generating assets constituting the proposed facility and would sell energy and capacity from the proposed facility into the Midcontinent Independent System Operator (MISO) markets.

27. Entergy has executed a build-own-transfer agreement with Liberty County Solar HoldCo, LLC (the seller)—a subsidiary of Recurrent Energy, Inc.—and Canadian Solar, Inc. for the acquisition of the project company. The seller owns 100% of the membership interests in the project company.

28. Entergy proposes to form a tax-equity partnership with an unaffiliated investor, then enter into an agreement under which, at closing, the tax-equity partnership would purchase from the seller and directly hold all membership interests in the project company. Entergy would hold a partnership interest in the tax-equity partnership.

29. Regardless of whether a tax-equity partnership is used, the project company would remain the direct owner of the proposed facility, and Entergy would at all times maintain control over the day-to-day operations of the proposed facility.

30. Entergy expects construction of the proposed facility to begin in mid-2022 and expects the sale of the project company's interests to close in early to mid-2023—after the proposed facility reaches mechanical completion. Entergy expects the proposed facility to achieve commercial operation by May 2023.

Regulatory Approvals

31. Entergy's application is sufficient for consideration.

32. Entergy's notice of the application in this proceeding is sufficient.

33. Entergy's acquisition of the membership interests in the project company requires regulatory approval only by the Commission.

34. The Commission may consider and grant Entergy's request to amend its CCN to acquire the proposed facility independent of Entergy's proposal to use a tax-equity partnership structure.

35. Entergy has not made commitments to any other regulatory authority regarding the proposed facility and would not pursue completion of the proposed facility before obtaining all necessary regulatory approvals.

36. Entergy does not propose or recommend that the Commission impose any conditions, reporting requirements, or reviews if the CCN amendment is approved.

37. No change should be made to the seven-year CCN authorization limit described in the Commission's preliminary order if the CCN amendment is approved.

38. If Entergy enters into a tax-equity partnership arrangement, four filings would need to be submitted to the Federal Energy Regulatory Commission (FERC): (1) a request that FERC accept a market-based rate tariff, so the proposed facility's capacity and energy could be offered into MISO markets; (2) an affiliate service agreement for Entergy Services LLC to provide shared support services relating to the proposed facility; (3) a request that FERC waive certain affiliate rules so Entergy Services LLC could submit offers into the MISO markets on behalf of the project company; and (4) a request for clarification and potential waiver of a FERC rule governing contracts and pricing for non-power goods and services between franchised public utilities and market-regulated power sales affiliates.

Alternatives Considered and Request for Proposals Process

39. Entergy controls approximately 3,395 MW of generating capacity through either ownership or long-term purchased-power agreements.

40. Entergy does not own any renewable generation. Gas generation comprises approximately 83% of its fleet, and Entergy relies on gas generation to fulfill 78% of its supply needs.

41. In its ongoing long-term resource planning process, Entergy considered a range of resource types and technologies and how those resources would meet the needs of its customers while considering reliability, economics, and risks.

42. Technologies Entergy considered to meet its long-term planning needs include: natural-gas-fired technologies (combustion turbine, combined-cycle gas turbine, aeroderivative combustion turbine, internal combustion engine, and reciprocating internal combustion engine); renewable technologies (solar photovoltaic and wind); and energy storage technologies (batteries).

43. The cost to install utility-scale solar generation has been declining significantly.

44. Entergy's decision, after considering other technologies as part of its long-term planning process, to conduct a solar-only request for proposals in order to meet its capacity, energy, and resource diversification needs, was reasonable.

45. On February 26, 2019, in a request for proposals (the solar request for proposals), Entergy notified potential bidders of its interest in procuring up to 200 MW of solar generation through both purchased-power-agreement and build-own-transfer resources.

46. Entergy required that the proposals be submitted by April 29, 2019, and that the proposals be active in the April 2018 MISO Definitive Planning Phase study or have a signed generator interconnection agreement from a previous such MISO study.

47. In response to the solar request for proposals, Entergy received ten bids from four proposed solar resources. Each resource submitted both a build-own-transfer bid and a purchased-power-agreement bid.

48. Given the bids received, Entergy's independent monitor suggested canceling the solar request for proposals and restarting but agreed with proceeding because starting the request-for-proposals process over would risk the opportunity of using the 30% solar investment tax credit.

49. Entergy then negotiated with two of the bidders, which led to agreements with Umbriel for a 150-MW solar purchased-power agreement and with the seller for acquisition of the 99.96-MW proposed facility.

50. The independent monitor concluded that each of the two proposals selected was clearly the best "in their respective category for purchased-power agreements and build-own-transfers."

51. In the solar request for proposals, Entergy received a purchased-power-agreement offer, for which the solar resource would have been the proposed facility, that Entergy calculated would result in $72 million net present value in net benefits. Entergy calculated that the proposed facility's build-own-transfer offer would result in $24 million net present value in net benefits.

52. Entergy did not demonstrate that it was reasonable to select the build-own-transfer offer for the proposed facility, whose net-present-value net benefits were lower than those of the purchased-power-agreement offer for the proposed facility as well as the Umbriel purchased-power-agreement offer.

<u>Adequacy of Existing Service, Need for Additional Service, Probable Improvement of Service and Reliability</u>

53. Although Entergy is able to provide adequate service under current conditions, Entergy needs additional capacity to meet the future resource needs of its retail customers.

54. Entergy projects it will have a capacity deficit of 244 MW in 2023 (when the proposed facility would be placed in service), 291 MW in 2024, and 233 MW in 2025, before dipping back to zero in 2026 after an additional combined-cycle gas turbine is brought online.

55. In recent years, Entergy has relied on the MISO planning resource auction for meeting capacity needs greater than its projected capacity need in 2023 through 2025, including purchasing 786 MW of capacity through the MISO planning resource auction in the 2020–2021 planning year.

56. Entergy plans to meet its remaining capacity need that would not be met by the proposed facility through the MISO planning resource auction.

57. Entergy projects that its MISO load resource zone, load resource zone 9, will have excess capacity and low planning-resource-auction prices until the mid-to-late 2020s.

58. With a nameplate capacity rating of 99.96 MW and 50 MW of MISO-accredited capacity, the proposed facility would help meet Entergy's capacity, energy, and resource diversification needs.

59. The addition of the proposed facility would provide Entergy a long-term hedge against uncertainty in the future cost of producing power.

60. The proposed facility is designed to enhance the reliable delivery of electric service during severe weather conditions.

61. The proposed facility's contribution to the fuel and technological diversity of Entergy's generation fleet and the proposed facility's placement within Entergy's service area would enhance reliability.

Probable Lowering of Cost to Consumers in the Area

The Proposed Facility's Cost and Revenue Source

62. The total estimated capital cost of the proposed facility is $157 million.

63. The first-year per-MW-hour (MWh) cost of the proposed facility is $92 per MWh.

64. The proposed facility's entire output would be sold into the MISO market.

Economic Modeling

65. Entergy's economic modeling assessed whether the proposed facility would provide net benefits to customers compared to other alternatives for meeting Entergy's capacity and energy needs.

66. The results of Entergy's updated economic modeling of the proposed facility's acquisition are summarized below:

Table 1: Proposal Net Benefit (Net Present Value, 2020 $MM)				
	With a tax-equity partnership		Without a tax-equity partnership	
	Net Benefit/(Cost)	Net Benefit/(Cost) With Fuel Price Stability	Net Benefit/(Cost)	Net Benefit/(Cost) With Fuel Price Stability
Reference Gas, Reference CO_2	$42.7	$51.4	$26.9	$36.6
Low Gas, No CO_2	$6.7	$15.4	$(9.6)	$0 0
High Gas, High CO_2	$144.8	$153.4	$130.0	$139.7

67. Entergy's economic modeling did not analyze whether customers would be better off if, instead of acquiring the proposed facility, Entergy met its near-term needs through bilateral contracts or the MISO planning resource auction.

68. As modeled by Entergy, any net benefits would occur late in the proposed facility's life.

69. The benefits of the proposed facility acquisition modeled by Entergy, which depend on future market prices of capacity and energy, are significantly less certain than the projected costs of that acquisition.

70. The evidence does not show that, under reasonable assumptions, Entergy's acquisition of the proposed facility will provide net benefits to customers.

71. Entergy has offered no guarantees to mitigate risks to its customers if its assumptions in its economic modeling of the proposed facility do not materialize.

72. The proposed facility's acquisition would not result in probable lowering of costs to Entergy's customers, and there is significant risk it would result in a negative net benefit.

Tax Equity Partnership

73. The tax-equity partnership market for renewable energy projects is well-developed.

74. If consummated, a tax-equity partnership is expected to lower the cost to customers of the proposed facility's acquisition.

75. Entergy is seeking CCN authorization for the proposed facility with or without a tax-equity partnership.

76. Entergy has not identified the proposed tax equity partner or negotiated or executed a tax-equity partnership agreement.

77. Contract terms that have not yet been negotiated or finalized in an agreement but would determine the tax-equity partnership's impact on Entergy's customers include the following: the rate of return required by the tax-equity partnership; the initial and subsequent or contingent capital contributions of each partner; the allocations between the partners of the partnership taxable income, the investment tax credit, and cash distributions; the hedge price; the flip date; and the purchase option.

78. Given the level of uncertainty about whether a tax-equity partnership will be used and the contract terms that would determine a tax-equity partnership's impact on the cost of the acquisition of the proposed facility to Entergy's customers, Entergy's quantification of benefits from using a tax-equity partnership should not be considered in determining that impact.

Natural Gas Prices

79. Entergy's economic analysis used the AURORA production model to forecast variable supply cost savings from adding the proposed facility to Entergy's generation portfolio.

80. Forecasted natural gas prices are an important determinant of whether modeling shows the proposed facility is economical.

81. In Entergy's model, higher natural gas price assumptions directly result in higher MISO power price assumptions and higher assumed net benefits for the proposed facility.

82. Entergy used its internal business-plan-2020 gas price forecast to forecast the expected project benefits. The business-plan-2020 forecast was created in December 2019.

83. The business-plan-2020 forecast contained gas price projections for a reference case (i.e., scenario), a high case, and a low case. Entergy's reference case had a levelized real gas price of approximately $3.49 per Million British Thermal Units (MMBtu) for the 2023–2039 portion of the evaluation period in which the AURORA model was run. For the

evaluation period, the 2020 levelized real gas price for the low case was approximately $2.46 per MMBtu and approximately $4.85 per MMBtu for the high case.

84. For its reference case, for year 1 of the forecast period, Entergy used a 30-day average of New York Mercantile Exchange (NYMEX) futures gas prices; for years 3-20, Entergy used an average of forecasts prepared by five consultants; for year 2, Entergy developed a linear interpolation between year 1 and year 3; and for years 21-30, Entergy used constant real dollars.

85. Entergy created an updated business-plan-2021 gas price projection in December 2020. The updated business-plan-2021 gas price projections were approximately 5% lower than the business-plan-2020 gas price projections. Entergy did not rerun its economic analysis of the proposed facility using its more current forecast.

86. For the last decade, Entergy's past forecasts have significantly overestimated actual natural gas prices, even in the near term.

87. NYMEX futures prices represent actual transactions between buyers and sellers who put real money at risk in their day-to-day operations.

88. The levelized average of trended NYMEX futures prices was $2.97 per MMBtu over the study period.

89. The NYMEX natural gas prices used by Entergy are now 15% higher than current real-time NYMEX natural gas prices.

90. A gas price forecast created using the methodology used by Southwestern Public Service Company (SPS) in recent Commission proceedings was lower than Entergy's business-plan-2020 reference case forecast. SPS's low-method forecast projected a levelized average price of $3.27 per MMBtu.

91. The lowest Energy Information Administration (EIA) case has been the most accurate at forecasting natural gas prices in recent years.

92. The levelized natural gas price for the 2021 version of EIA's lowest case is $3.57 per MMBtu.

93. The natural gas price forecast used in Entergy's low case is more likely to be accurate than the forecast used in Entergy's reference case.

94. Entergy's reference case is based on natural gas prices that are too high and overstate the value of the proposed facility.

Carbon Tax

95. Entergy evaluated the expected customer benefits of the proposed facility acquisition both with and without an assumption that a carbon tax will be enacted.

96. In the scenarios that assumed a carbon tax will be enacted, Entergy assumed the tax would be enacted in the 2025-2026 timeframe.

97. Entergy's carbon tax assumption increased the customer benefits of the proposed facility by $15 million net present value for Entergy's reference case.

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

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

100. The United States Congress has never adopted a carbon tax, but it has extended tax credits for renewable generation sources, such as the solar investment tax credit, on numerous occasions, including in December 2020.

101. Entergy did not include any cases with an assumption that new renewable-energy subsidies would be adopted or that existing renewable-energy subsidies would be extended. Each of those assumptions would cause the proposed facility to appear less economic than it otherwise would.

102. Entergy's modeling should not have included the carbon-tax component, and the calculation of the estimated benefits of the project should not include that component.

Modeling of Future Generation Mix in MISO

103. In the AURORA model Entergy used to project power prices through 2039, power prices decrease with the addition of newer, more efficient generation and penetration of renewable generation, which has no marginal cost.

104. Entergy assumed the same generation expansion plan in all of its cases, which was not reasonable because the cases included different assumptions regarding gas prices and a carbon tax.

105. Entergy assumed the addition of renewable generation and combined-cycle gas turbines in MISO South during the 2020s but mainly assumed the addition of new combustion turbines during the 2030s.

106. Entergy assumed that the generation mix in MISO South would remain the same from 2039 through the end of the study period.

107. Entergy's assumptions regarding the future generation mix in MISO South do not account for the likelihood that additional renewable generation and technological improvements will result in lower power prices.

Capacity Value

108. Entergy evaluated the proposed facility's capacity value based on the cost of new entry, an economic concept that values capacity based on the levelized cost of the most economical new-build capacity alternative, which Entergy assumes to be a combustion turbine.

109. Entergy is paid the annual planning-resource-auction prices for its additional capacity if it is capacity-long and is required to pay planning-resource-auction prices for its capacity deficit if it is capacity-short.

110. Entergy calculated the proposed facility's capacity value based on the cost of new entry from 2023 until the end of the proposed facility's service life.

111. The cost of new entry is the highest level to which MISO planning-resource-auction prices can rise.

112. Since 2015, there have been seven planning auctions for 10 MISO load resource zones, and only one of the resulting 70 planning-resource-auction clearing prices reached the cost of new entry.

113. Entergy's load resource zone, load resource zone 9, has never had its planning-resource-auction clearing price set at the cost of new entry. In the most recent planning resource auction, the clearing price for load resource zone 9 was set at $0.01 per MW-day for the 2021--2022 planning year.

114. Entergy's internal projections forecast that MISO planning-resource-auction prices will remain low until capacity in MISO reaches equilibrium, which Entergy projects will not happen until the mid-to-late 2020s.

115. Entergy's calculation of the capacity benefits of the proposed facility overstates its value.

Useful Life of the Proposed Facility

116. Entergy's economic analysis of the proposed facility assumes it will have a useful service life of 30 years.

117. The evidence relating to a solar panel warranty does not support using a 30-year useful life.

118. The Umbriel purchased-power agreement would have a 20-year term.

119. Extending the proposed facility's useful life beyond 25 years depends on costs that may outweigh the benefits.

120. Any net benefits of the proposed facility would come after year 25.

121. The proposed facility's having a 30-year useful life is too uncertain to be used in calculating whether the proposed facility would result in probable lowering of costs to customers.

122. The proposed facility should be evaluated using a 25-year useful life.

Terminal Value

123. Entergy calculated a terminal value of the proposed facility based on a projection of net benefits in years 31 through 40.

124. Entergy's terminal value calculation uses the same assumptions regarding natural gas prices and power prices that Entergy used for years 1 through 30.

125. Entergy's terminal value calculation assumes the proposed facility could continue to be operated economically during years 31 through 40 without any additional capacity costs, except that some cases assume inverter costs.

126. Entergy's having a terminal value in years 31 through 40 is too uncertain to be used in calculating the economics of the proposed facility.

Gas Price Stability Adder

127. As a sensitivity, Entergy calculated a gas price stability value for the proposed facility based on its estimate of what it would have to pay counterparties to provide such a hedge.

128. To quantify the proposed facility's gas price stability value, Entergy estimated the cost to obtain a similar level of stability if Entergy entered into a long-term contract-for-differences for natural gas as a means to hedge MISO spot market purchases.

129. Entergy has no such gas hedges in place nor any plans to obtain them.

130. Entergy calculated its gas price stability adder based on quotes from counterparties for the cost of entering into a 30-year gas hedging transaction. The counterparties do not offer such a hedging product.

131. Because Entergy considers the quotes it received as merely indicative, an amount was added to the quotes to arrive at the cost of the hedge used in calculating the proposed facility's gas price stability value.

132. Entergy's calculation of the proposed facility's gas price stability value is not reliable and should not be used in considering whether the proposed facility would result in probable lowering of costs to Entergy customers.

Capacity Factor

133. Entergy's economic analysis used a P50 capacity factor for the proposed facility of 26.31%. P50 is the level at which 50% of the cases show a lower output and the other 50% show a higher output.

134. The proposed facility's project developer guaranteed output from the proposed facility at the P90 level of 25%.

135. Evaluating the economics of the proposed facility under a P90 capacity factor is a reasonable stress-test of the economics of the project.

136. Entergy did not present an economic analysis that evaluated the proposed facility under a P90 capacity factor.

137. Using a lower capacity factor would reduce the proposed facility's capacity benefits.

138. The P90 capacity factor for the proposed facility of 25% should be used instead of the P50 capacity factor for the proposed facility of 26.31% in considering whether the proposed facility would result in probable lowering of costs to Entergy customers.

Decommissioning Costs

139. Entergy assumed zero decommissioning costs based on its assumption that dismantling costs would be offset by salvage value.

140. Assuming significant salvage value for solar panels that far into the future is speculative.

141. In evaluating whether the proposed facility would result in probable lowering of costs to customers, $10 million ($0.6 million net present value) of dismantling costs should be included.

Effect of Granting the CCN on Entergy and Other Electric Utilities

142. The City of Liberty Electrical Department and CenterPoint Energy Houston Electric, LLC have facilities within three miles of the proposed facility's site.

143. Granting the CCN application would have no impact on electric utilities serving the proximate area.

144. Effects on Entergy of granting the application include the following: (1) increasing the diversity of its generation resource portfolio and helping hedge against volatile natural gas prices; (2) providing incremental capacity to help address Entergy's short-term and long-term needs; and (3) providing energy benefits with no fuel costs that would mitigate exposure to MISO capacity and energy markets.

Community Values

145. Preferences for sustainable energy as increasingly expressed by customers in Entergy's service area are a community value.

146. The proposed facility would help satisfy that community value.

147. The proposed CCN amendment would not result in adverse effects to community values.

Recreational and Park Areas

148. No parks or other public open spaces are located in the immediate vicinity of the proposed facility's site.

149. A wildlife refuge is located approximately 1.2 miles away from the proposed facility's site, and the nearest public recreation area is the Eagle Point Golf Club, located approximately 3.6 miles south of the proposed facility's site.

150. No park or recreational area, including the wildlife refuge and the Eagle Point Golf Club, would be adversely affected by the proposed facility.

Historical and Aesthetic Values

151. No archeological sites have been documented within a half-mile of the proposed facility's site.

152. The National Register of Historic Places contains no documented historical properties within or near the proposed facility's site.

153. The elevated Coastal Water Authority canal would serve as a buffer between the proposed facility and adjacent residential areas to the east and southeast, and forested land would serve as a buffer between the proposed facility and residential areas to the north and northeast.

154. The proposed facility would have no adverse effect on historical values and minimal adverse effect on aesthetic values.

Environmental Integrity

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

156. The proposed facility would not include any significant emissions during operations.

157. The proposed facility is expected to have minimal adverse effect on the environmental integrity of the site or surrounding area.

Effect of Granting the CCN on the State's Ability to Meet the Goal Established by PURA § 39.904(a)

158. Texas has met the goal of establishing 10,000 MW of installed renewable capacity for the state by January 1, 2025, as set out in PURA § 39.904(a).

159. The proposed facility would not contribute toward meeting Texas's renewable energy goal.

Texas Parks and Wildlife Department

160. In a November 3, 2020 letter, the Texas Parks and Wildlife Department provided comments and recommendations on Entergy's application.

161. Because the application should not be granted, none of the Texas Parks and Wildlife Department's recommendations should be included in the Commission's Order.

Other Issues

162. Whether Entergy should recover its transaction costs, project oversight costs, and allowance for funds used during construction related to project construction financing and contingency costs are not issues to be determined in this proceeding.

163. If the Commission grants Entergy's CCN amendment, recovery of such costs should be determined in a future rate proceeding.

II. Conclusions of Law

The Commission adopts the following conclusions of law.

1. The Commission has jurisdiction over this matter under PURA §§ 14.001, 37.051(a), 37.053, 37.056, 37.058(d), and 39.452(j).

2. SOAH has jurisdiction over this proceeding, including the preparation of a proposal for decision with findings of fact and conclusions of law, under PURA § 14.053 and Texas Government Code § 2003.049.

3. Because the proposed facility does not yet exist and would not be built until regulatory approvals have been obtained, the 366-day case-processing timeline set forth in PURA § 37.058(d) applies to this proceeding.

4. This case was processed in accordance with the requirements of PURA, the Administrative Procedure Act,[2] and Commission rules.

5. Entergy provided notice of the application in compliance with PURA § 37.054 and 16 Texas Administrative Code (TAC) §§ 22.52(a) and 22.55.

---

[2] Texas Government Code chapter 2001.

6. DELETED.

7. Entergy is a public utility as that term is defined in PURA § 11.004(1) and an electric utility as that term is defined in PURA § 31.002(6).

8. Under the structure proposed by Entergy, the project company would be a power generation company under PURA § 31.002(10) and would not be an electric utility under PURA § 31.002(6).

9. Under the structure proposed by Entergy, the tax-equity partnership would be neither a power generation company under PURA § 31.002(10) nor an electric utility under PURA § 31.002(6).

10. DELETED.

11. Entergy's service is adequate, but Entergy has a need for additional service under PURA § 37.056(c)(1) through (3), in that it needs additional capacity, energy, and resource diversity, which the proposed facility would help provide.

12. The requested CCN amendment would not adversely affect any electric utility serving the proximate area under PURA § 37.056(c)(3).

13. The requested CCN amendment would satisfy community values under PURA § 37.056(c)(4)(A), in that Entergy's customers have increasingly expressed a desire to be served using renewable energy.

14. The requested CCN amendment would not adversely affect recreational and park areas or historical values under PURA § 37.056(c)(4)(B)–(C).

15. The requested CCN amendment would have a minimal adverse effect on aesthetic values and environmental integrity under PURA § 37.056(c)(4)(C)–(D).

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

17. Entergy did not demonstrate acquisition of the proposed facility is an economical alternative for meeting its capacity, energy, and resource diversity needs under PURA § 37.056(c)(4)(E).

18. The requested CCN amendment would not affect the renewable energy goal established by PURA § 39.904(a) because that goal has already been met under PURA § 37.056(c)(4)(F).

19. The Commission may grant a CCN amendment only if the Commission finds it is necessary for the service, accommodation, convenience, or safety of the public under PURA § 37.056.

20. Based on consideration of the factors set forth in PURA § 37.056(c), Entergy has not met its burden of proof to show that the project is necessary for the service, accommodation, convenience, or safety of the public under PURA § 37.056.

21. Entergy is not entitled to approval of the application.

III. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following orders:

1. The Commission adopts the proposal for decision.

2. The Commission denies the application, as outlined in this Order.

3. The parties must file in this docket a joint list of exhibits that marks which ones are still confidential and which ones were declassified. The list must also specify which parts of the hearing transcript are still confidential and which are now declassified.

4. The Commission denies all other motions and any other requests for general or specific relief that have not been expressly granted.

Signed at Austin, Texas the 19th day of October 2021.

PUBLIC UTILITY COMMISSION OF TEXAS

PETER M. LAKE, CHAIRMAN

WILL MCADAMS, COMMISSIONER

JIMMY GLOTFELTY, COMMISSIONER

W2013
q.\cadm\orders\final\51000\51215 fo docx

Filing Receipt

Received - 2022-08-02 04:11:11 PM
Control Number - 53593
ItemNumber - 30

SOAH Docket No. 473-22-2694 Suffix: PUC
PUC Docket No. 53593

BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

APPLICATION OF ENTERGY TEXAS, INC. TO IMPLEMENT AN INTERIM FUEL SURCHARGE

SOAH ORDER NO. 2
FINDING APPLICATION AND NOTICE SUFFICIENT; ADMITTING EVIDENCE; APPROVING INTERIM RATES; AND REMANDING PROCEEDING

On July 22, 2022, Entergy Texas, Inc. filed an Agreed Motion to Find Application and Notice Sufficient, Admit Evidence, Approve Interim Rates, and Remand Proceeding, on behalf of itself, the Cities,[1] Texas Industrial Energy

[1] The cities included within Cities are: Anahuac, Beaumont, Bridge City, Cleveland, Dayton, Groves, Houston, Huntsville, Liberty, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Pinehurst, Port Arthur, Port Neches, Roman Forest, Rose City, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, West Orange, and Willis.

Consumers(TIEC), and the staff (Staff) of the Public Utility Commission of Texas (Commission).[2]

The Administrative Law Judge (ALJ) concludes the joint agreed motion has merit and should be **GRANTED**.

I. FINDING APPLICATION AND NOTICE SUFFICIENT

Staff recommended ETI's proposed notice and application be found sufficient on May 23, 2022, and June 6, 2022, respectively. On June 13, 2022, ETI filed its proof of notice pursuant to the procedural schedule adopted by the ALJ at the May 31, 2022 prehearing conference. No objections to ETI's provision of notice were filed.

Accordingly, the ALJ finds ETI's application and notice are sufficient.

II. ADMITTING EVIDENCE

The following documents are **ADMITTED** into evidence:

[2] Cities and TIEC filed motions to intervene on May 19, 2022, and 24, 2002, respectively. Those motions are **GRANTED** without objection.

Exhibit	Commission Interchange Item No.	Filing Description
a	2	ETI's Application including all attachments and the direct testimony and exhibits of Scott M. Celino filed on May 13, 2022
b	21	ETI's Proof of Notice filed on June 13, 2022
c	24	ETI's Response to Staff's Request for Information filed on June 15, 2022
d	26	ETI's Errata to the Application filed on July 14, 2022
e	28	Unanimous Stipulation and Settlement Agreement and attachment filed on July 22, 2022

III. APPROVING INTERIM RATES

The agreed joint motion indicates the parties have agreed that ETI should be allowed to implement its proposed surcharge rates on an interim basis if the Commission has not issued a final order in this proceeding in time for ETI to implement the fuel surcharge effective with the first billing cycle in September 2022, subject to refund or surcharge to the extent the rates finally established by the Commission differ from the interim rates. Thus, the parties request that ETI be authorized to begin charging the rates in Proposed Rate Schedule FS-11 (as attached to ETI's Application as Attachment C) on an interim basis, on the first day of ETI's September 2022 billing cycle (August 30, 2022) if the Commission has not issued a final order by that date, subject to refund or surcharge as addressed above.

Interim relief may be granted based on the agreement of all parties.[3] A request for interim relief must be filed no later than 30 days before the interim relief is proposed to take effect, unless all parties agree to a later filing date.[4]

The ALJ concludes the requirements for interim rates are met and **APPROVES** ETI's rates as detailed in its Proposed Rate Schedule FS-11 on an **INTERIM BASIS** beginning August 30, 2022. The approved interim rates are subject to adjustment if they differ from the final rates approved by the Commission. Additionally, within 10 days of the date of this order, ETI **SHALL** file a clean copy of the Proposed Rate Schedule FS-11, to be stamped "Approved" by Central Records.

IV. REMAND TO THE COMMISSION AND DISMISSAL FROM SOAH'S DOCKET

Because there are no longer any contested issues, this case is **REMANDED** to the Commission and **DISMISSED** from the docket of the State Office of Administrative Hearings.

The Parties' Unanimous Stipulation and Settlement Agreement, filed contemporaneously with the agree joint motion, includes a proposed order as Attachment A with proposed findings of fact, conclusions of law, and ordering paragraphs. As soon as practicable, SPS **SHALL** e-mail a Word version of the proposed order to the Commission at cadmorders@puc.texas.gov.

[3] 16 Tex. Admin. Code § 22.125(c).

[4] 16 Tex. Admin. Code § 22.125(b).

SIGNED AUGUST 2, 2022

ALJ Signature:

Meaghan Bailey,

Presiding Administrative Law Judge

Filing Receipt

Received - 2022-07-22 12:06:06 PM
Control Number - 53593
ItemNumber - 29

SOAH DOCKET NO. 473-22-2694
PUC DOCKET NO. 53593

APPLICATION OF ENTERGY TEXAS, INC. TO IMPLEMENT AN INTERIM FUEL SURCHARGE	**§ § §**	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement (Stipulation or Agreement) is entered into by and between Entergy Texas, Inc. ("ETI"), the Commission Staff ("Staff") of the Public Utility Commission of Texas ("Commission"), and Texas Industrial Energy Consumers ("TIEC") (together, the "Signatories"). Cities[1] are unopposed. The Signatories stipulate and agree as follows:

I. BACKGROUND

On May 13, 2022, ETI filed its application, supporting testimony, fuel and purchased power costs summary, proposed notice, and proposed rate schedule with the Commission in this docket requesting approval to implement an interim fuel surcharge to collect its under-recovered fuel and purchased power costs incurred from May 1, 2020 through December 31, 2021. The Signatories believe that a resolution of this docket pursuant to the terms stated herein is in the public interest and that the result is reasonable under the circumstances. Settlement of this matter will also conserve the resources of the public and the Signatories and will eliminate controversy. The Signatories jointly request approval of this Stipulation and entry of orders, findings of fact, and conclusions of law consistent with that approval.

II. AGREEMENT

By this Stipulation, the Signatories agree to the following terms in settlement of the issues

[1] The Cities of Anahuac, Beaumont, Bridge City, Cleveland, Dayton, Groves, Houston, Huntsville, Liberty, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Pinehurst, Port Arthur, Port Neches, Roman Forest, Rose City, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, West Orange, and Willis ("Cities").

in Docket No. 53593:

1. **Application.** The Signatories support or do not oppose the approval of ETI's application consistent with the terms of this Stipulation and subject to the following agreed provisions:

   a. The reasonableness of ETI's eligible fuel, fuel-related, and purchased power expenses and revenues for the months of May 2020 through December 2021 will be determined in ETI's next fuel reconciliation case.

   b. The appropriate allocation of ETI's eligible fuel, fuel-related, and purchased-power expenses and revenues among retail rate classes for the months of May 2020 through December 2021 will be determined in ETI's next fuel reconciliation case.

2. **Support of Stipulation and Proposed Order.** The Signatories support this Stipulation and request entry of an order consistent with the proposed order included as Attachment A to this Stipulation.

3. **Interim Rates.** The Signatories agree to support an order authorizing ETI to begin charging the rates in Proposed Rate Schedule FS-11[2] on an interim basis, on the first day of ETI's September 2022 billing cycle, which is August 30, 2022, if the Commission has not issued a final order by that date, subject to refund or surcharge to the extent the rates ultimately established differ from the interim rates.

4. **Agreed Evidence.** The Signatories agree to the admission into evidence of the following documents: ETI's Application including all attachments and the Direct Testimony and Exhibits of Scott M. Celino filed on May 13, 2022; ETI's Proof of

[2] ETI's Application, Attachment C.

Notice filed on June 13, 2022; ETI's Response to Staff's Request for Information filed on June 15, 2022; ETI's Errata to the Application filed on July 14, 2022; and this Stipulation and all of its attachments.

5. **Effect of Stipulation.**

a) The terms of this Stipulation may not be used either as an admission or concession or evidence in any other proceeding. The Signatories further agree that all oral or written statements made during the course of the settlement negotiations may not be used for any purpose and are governed by Texas Rule of Evidence 408. The obligations set forth in this subsection shall continue and be enforceable, even if this Stipulation is terminated as provided below.

b) This Stipulation is binding on each Signatory only for the purpose of settling the issues as set out herein and for no other purpose. Except to the extent that this Stipulation expressly governs a Signatory's rights and obligations for future periods, this Stipulation, including all terms provided herein, shall not be binding or precedential on a Signatory outside of this case except for a proceeding to enforce the terms of this Stipulation. The Signatories acknowledge and agree that a Signatory's support of the matters contained in this Stipulation may differ from its position or testimony in other proceedings. To the extent there is a difference, a Signatory does not waive its position in such other proceedings. Because this is a settlement agreement, a Signatory is under no obligation to take the same position as set out in this Stipulation in other proceedings, whether those proceedings present the same or a different set of circumstances. A Signatory's agreement to support issuance of a final order of the Commission consistent with this Stipulation should not be regarded as an agreement to the appropriateness or correctness of any assumptions, methodology, or legal or regulatory principle that may have been employed in reaching this Stipulation.

c) If the Commission does not accept this Stipulation as presented or enters an order inconsistent with any material term of this Stipulation, any Signatory shall have the right to withdraw from all commitments and obligations and to seek a hearing on all issues, present evidence, and advance any positions it desires, as if it had not been a Signatory.

d) This Stipulation contains the entire understanding and agreement of the Signatories, supersedes all other written and oral exchanges or negotiations among them or their representatives with respect to the subjects contained herein. Neither this Stipulation nor any of the terms of this Stipulation may be altered, amended, waived, terminated, or modified, except by a writing properly executed by the Signatories.

e) There are no third-party beneficiaries of this Stipulation. Although this Stipulation represents a settlement among the Signatories with respect to some of the issues presented in this proceeding, this Stipulation is merely a settlement proposal submitted to the Commission, which has the authority to enter an order resolving these issues.

f) This Stipulation is a complete resolution of all contested issues in this proceeding.

6. **Execution.** The Signatories agree that this document may be executed in multiple counterparts and filed with facsimile or electronic signatures. The Signatories agree that they will use their best efforts to obtain expeditious implementation of this Stipulation by entry of appropriate orders.

Signatures are on the following pages.

SIGNATORIES:

ENTERGY TEXAS, INC.

By: /s/ Laura B. Kennedy

Date: July 22, 2022
Laura B. Kennedy
Everett Britt
Attorneys of Record

PUBLIC UTILITY COMMISSION OF TEXAS STAFF

By: /s/ Scott Miles

Date: July 22, 2022
Scott Miles
Anthony Kanalas
Attorneys of Record

TEXAS INDUSTRIAL ENERGY CONSUMERS

By: /s/ Benjamin B. Hallmark

Date: July 22, 2022
Rex D. VanMiddlesworth
Benjamin B. Hallmark
Christian E. Rice
Attorneys of Record

UNOPPOSED PARTIES:

CITIES

By: /s/Molly Mayhall Vandervoort

Date: July 22, 2022
Molly Mayhall Vandervoort
Daniel J. Lawton
Attorneys of Record

PUC DOCKET NO. 53593
SOAH DOCKET NO. 473-22-2694

APPLICATION OF ENTERGY TEXAS, INC. TO IMPLEMENT AN INTERIM FUEL SURCHARGE	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

AGREED PROPOSED ORDER

This Order addresses the application of Entergy Texas, Inc. ("ETI") to implement an interim fuel surcharge to recover a material Texas retail jurisdictional under-recovery of eligible fuel and purchased power costs incurred from May 1, 2020 through December 31, 2021. The total amount of the under-recovery balance proposed to be collected through the proposed surcharge is approximately $51.7 million, including interest. ETI filed an unopposed agreement among the parties that resolves all issues for this proceeding. The Commission authorizes ETI to implement the requested surcharge to the extent provided in this Order.

I. Findings of Fact

The Commission makes the following findings of fact:

Applicant

1. ETI is a Texas corporation registered with the Texas secretary of state under file number 800911623.

2. ETI owns and operates for compensation equipment and facilities to generate, transmit, distribute, and sell electricity in Texas.

3. ETI is required under certificate of convenience and necessity number 30076 to provide service to the public and to provide retail electric utility service within its certificated service area.

Application

4. On May 13, 2022, ETI filed with the Commission an application for authority to implement an interim fuel surcharge.

5. On June 6, 2022, Commission Staff filed a recommendation that ETI's application be found sufficient.

6. On July 14, 2022, ETI filed errata to its application to correct statements regarding the date through which interest included in the proposed surcharge was calculated.

7. In SOAH Order No. __ filed on July __, 2022, the SOAH ALJ found that ETI's application was sufficient.

Notice

8. On May 13, 2022, ETI provided notice to all parties that participated in ETI's most recent fuel reconciliation proceeding (Docket No. 49916).

9. ETI provided notice by one-time publication in newspapers of general circulation in the counties comprising ETI's service territory. Publication was completed on May 26, 2022.

10. On May 23, 2022 Commission Staff filed a recommendation that ETI's proposed notice be found sufficient.

11. ETI filed its proof of notice and publication with supporting affidavits on June 13, 2022.

12. In SOAH Order No. __ filed on July __, 2022, the SOAH ALJ found that ETI's notice was sufficient.

Referral to SOAH

13. On May 16, 2022, the Commission referred this proceeding to SOAH and issued a preliminary order.

14. In SOAH Order No. 1 filed on May 17, 2022, the SOAH ALJ found that the Commission has jurisdiction over this proceeding; required Commission Staff to file comments on the sufficiency of ETI's proposed notice; adopted the Commission's standard protective order; requested clarification from ETI regarding whether its application is subject to the procedural schedule deadlines set forth in 16 Tex. Admin. Code (TAC) § 25.237(e)(1) or 16 TAC § 25.237(e)(2); scheduled the prehearing conference; and set the procedures for the docket.

15. On May 20, 2022, ETI filed a clarification regarding the procedural schedule as requested by the SOAH ALJ in Order No. 1 stating that ETI's fuel factor is determined using a Commission-approved, utility-specific fuel factor formula pursuant to 16 TAC § 25.237(a)(1)(B), that the formula methodology for ETI was adopted by the Commission in Docket No. 32915, and that, therefore, ETI's application in this proceeding is subject to the procedural schedule deadlines set forth in 16 TAC § 25.237(e)(2).

16. At the prehearing conference on May 31, 2022, the SOAH ALJ (1) granted the motions to intervene of the Cities of Anahuac, Beaumont, Bridge City, Cleveland, Dayton, Groves, Houston, Huntsville, Liberty, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest,

Pinehurst, Port Arthur, Port Neches, Roman Forest, Rose City, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, West Orange, and Willis (Cities), and Texas Industrial Energy Consumers (TIEC) and (2) approved a procedural schedule.

17. On June 13, 2022, TIEC filed a request for hearing.

18. On July 22, 2022, ETI filed an agreement among the parties that was signed by ETI, Commission Staff, and TIEC. Cities is not a signatory but does not oppose the agreement.

19. In SOAH Order No. _ filed on July _, 2022, the SOAH ALJ dismissed this proceeding from SOAH's docket and remanded it to the Commission.

Evidentiary Record

20. In SOAH Order No. __ filed on July __, 2022, the SOAH ALJ admitted the following into evidence: 1) ETI's application including all attachments and the direct testimony and exhibits of Scott M. Celino, filed on May 13, 2022; 2) ETI's proof of notice, filed on June 13, 2022; 3) ETI's response to Commission Staff's request for information, filed on June 15, 2022; 4) ETI's errata to the application, filed on July 14, 2022; and 5) the agreement and all attachments filed on July 22, 2022.

Agreement

21. The signatories agreed to ETI's proposed interim fuel surcharge subject to the following provisions:

    a. The reasonableness of ETI's eligible fuel, fuel-related, and purchased power expenses and revenues for the months of May 2020 through December 2021 will be determined in ETI's next fuel reconciliation case.

    b. The appropriate allocation of ETI's eligible fuel, fuel-related, and purchased-power expenses and revenues among retail rate classes for the months of May 2020 through December 2021 will be determined in ETI's next fuel reconciliation case.

22. The signatories agreed to support issuance of an order authorizing ETI to implement its proposed fuel surcharge on an interim basis in the event the Commission had not issued a final order by August 30, 2022, subject to refund or surcharge to the extent the rates ultimately established in this docket differ from the interim rates.

Amount of Fuel-Cost Under-Recovery Balance

23. During the period May 1, 2020 through December 31, 2021, ETI incurred over $990,453,773 in eligible fuel and purchased power expenses to generate and purchase electricity, net of certain revenues properly credited to such expenses.

24. ETI's application proposed an interim net surcharge of $51,677,917 consisting of an under-recovered balance of $52,176,089 minus $498,172 in cumulative interest, for over- and under-recoveries of reconcilable fuel costs through December 2021.

25. A "material" under-recovery, as defined by 16 TAC § 25.237(a)(3)(B), means that the cumulative amount of over- or under-recovery, including interest, is greater than or equal to 4.0% of the annual actual fuel cost figures on a rolling 12-month basis, as reflected in the utility's monthly fuel cost reports as filed by the utility with the Commission.

26. As of December 31, 2021, ETI's annual actual fuel cost on a rolling 12-month basis was $736,846,424, such that a "material" under-recovery for ETI was $29,473,857 or more.

27. ETI's net fuel under-recovery balance as of December 31, 2021, exceeds 4.0% of the annual actual fuel cost figures on a rolling 12-month basis, as reflected in ETI's fuel cost reports as filed by ETI with the Commission.

28. ETI is in a state of material under-collection and projects that it will continue to be in a state of material under-collection absent the requested surcharge.

Surcharge Period

29. ETI requested that customers be assessed a surcharge over a period of six months beginning with the first billing cycle for the first billing month after the Commission issues a final order, but not later than ETI's first billing cycle for the billing month of September 2022.

30. Unless otherwise ordered by the Commission, 16 TAC § 25.236(e)(5) requires that all surcharges be made on a monthly basis over a period not to exceed 12 months through a bill charge.

31. ETI's requested surcharge period is less than 12 months.

32. ETI's proposed surcharge period of six months is reasonable.

Calculation of Proposed Surcharge

33. The calculation of ETI's under-recovery balance, interest on the balance and for the surcharge, and the allocation of the surcharge among and within the rate classes was described in the direct testimony and exhibits of ETI witness Scott M. Celino.

34. A copy of the proposed surcharge was included as Attachment C to the application.

35. Under the agreement of the parties, the reasonableness of ETI's eligible fuel, fuel-related, and purchased power expenses and revenues for the months of May 2020 through December 2021 will be determined in ETI's next fuel reconciliation case.

36. Under the agreement of the parties, the appropriate allocation of ETI's eligible fuel, fuel-related, and purchased-power expenses and revenues among retail rate classes for the months of May 2020 through December 2021 will be determined in ETI's next fuel reconciliation case.

37. ETI has properly calculated the proposed interim fuel surcharge, including applicable interest, for purposes of this proceeding.

Interim Rates

38. In SOAH Order No. __, the SOAH ALJ granted the agreed motion to authorize ETI to implement the fuel surcharge rates proposed in its application on an interim basis effective August 30, 2022, if the Commission has not issued a final order in this proceeding in time for ETI to implement the interim fuel surcharge effective with the first billing cycle in September, subject to refund or surcharge to the extent the rates finally established in this docket differ from the interim rates.

39. ETI implemented interim rates on August 30, 2022.

40. The rates established in this Order do not differ from the interim rates.

Informal Disposition

41. More than 15 days have passed since completion of the notice provided in this docket.

42. ETI, Commission Staff, Cities, and TIEC are the only parties to this proceeding.

43. All parties to this proceeding support or do not oppose the agreement.

44. The decision is not adverse to any party.

45. TIEC's support of the agreement moots its request for hearing; no hearing is necessary for this proceeding.

II. Conclusions of Law

The Commission makes the following conclusions of law:

1. ETI is a public utility as that term is defined in PURA § 11.004(1) and an electric utility as defined in PURA § 31.002(6).

2. The Commission has jurisdiction over this matter under PURA §§ 14.001, 32.001, 36.001, and 36.203 and 16 TAC §§ 25.235-.237.

3. ETI provided notice of its application in compliance with 16 TAC § 25.235(b).

4. This proceeding was processed in accordance with the requirements of PURA, the Administrative Procedure Act,[1] and Commission rules.

5. ETI has materially under-collected its fuel and purchased power costs and projects a continued state of material under-collection under 16 TAC § 25.237(a)(3)(B).

6. The reasonableness of ETI's eligible fuel, fuel-related, and purchased power expenses and revenues for the months of May 2020 through December 2021 will be determined in ETI's next fuel reconciliation case.

7. The appropriate allocation of ETI's eligible fuel, fuel-related, and purchased-power expenses and revenues among retail rate classes for the months of May 2020 through December 2021 will be determined in ETI's next fuel reconciliation case.

8. The proposed interim fuel surcharge complies with the applicable requirements of 16 TAC §§ 25.236(e) and 25.237, respectively.

9. This proceeding meets the requirements for informal disposition 16 TAC § 22.35.

III. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following orders:

1. The Commission approves ETI's interim fuel surcharge as proposed in the application to the extent provided in this Order.

2. Subject to final reconciliation during ETI's next applicable fuel reconciliation proceeding, ETI shall implement a surcharge to collect its under-recovery balance incurred during the period May

[1] Tex. Gov't Code §§ 2001.001-.903.

1, 2020 through December 31, 2021, including interest through the end of the surcharge period, as proposed in ETI's application.

3. ETI must implement the interim fuel surcharge as provided by this Order over a six-month period.

4. Within ten days of the date of this Order, ETI must file a clean copy of its surcharge tariff with Central Records to be marked *Approved* and kept in the Commission's tariff book.

5. The reasonableness of the fuel costs that are the subject of the surcharge approved by this Order shall be reviewed in a fuel reconciliation proceeding under 16 TAC §§ 25.235(b)(2)(C), 25.236(d)(2), and 25.237(a)(3)(A).

6. The appropriate allocation of ETI's eligible fuel, fuel-related, and purchased-power expenses and revenues among retail rate classes for the months of May 2020 through December 2021 shall be determined in ETI's next fuel reconciliation case.

7. Entry of this Order does not indicate the Commission's endorsement or approval of any principle or methodology that may underlie the agreement and must not be regarded as precedential as to the appropriateness of any principle or methodology underlying the agreement.

8. The Commission denies all other motions and any other requests for general or specific relief that have not been expressly granted.

SIGNED AT AUSTIN, TEXAS on the________day of [Month] 2022.

PUBLIC UTILITY COMMISSION OF TEXAS

____

PETER M. LAKE, CHAIRMAN

____

WILL MCADAMS, COMMISSIONER

____

LORI COBOS, COMMISSIONER

____

JIMMY GLOTFELTY, COMMISSIONER

Laura Bradshaw Kennedy
Senior Counsel
Legal Services – Regulatory
Entergy Services, LLC
512-487-3961 | lkenn95@entergy.com
919 Congress Ave., Suite 701, Austin, TX 78701

August 26, 2022

Central Records
Public Utility Commission of Texas
1701 N. Congress Avenue, 7th Floor
Austin, Texas 78711-3326

Re: Docket No. 53979/ SOAH Docket No. 473-22-08897; *Application of Entergy Texas, Inc. to Revise Fixed Fuel Factor (Schedule FF) in Compliance with Order in Docket No. 32915*

Dear Central Records:

The State Office of Administrative Hearings ("SOAH") Administrative Law Judge issued Order No. 2 in the above-referenced docket on August 25, 2022. As part of Order No. 2, the SOAH Administrative Law Judge approved ETI's proposed revision to its fixed fuel factor on an interim basis effective August 30, 2022 and required ETI to file a clean copy of its Revised Fixed Fuel Factor (Schedule FF) with the Commission to be stamped as "Approved" by the Commission's Central Records Division. Pursuant to Order No. 2, ETI submits the attached clean copy of Schedule FF to Central Records to be marked *Approved* and filed in the Commission's tariff book.

Thank you for your assistance in this matter. If you have any questions, please do not hesitate to contact the undersigned counsel.

Sincerely,

Laura B. Kennedy
Laura Bradshaw Kennedy

Enclosure

cc: Commission Legal Staff
Office of Public Utility Counsel
Cities
Texas Industrial Energy Consumers

ENTERGY TEXAS, INC. Electric Service SCHEDULE FF	Sheet No.: 51 Effective Date: 8-30-22 Revision: 55 Supersedes: FF Effective 3-2-22 Schedule Consists of: One Sheet

FIXED FUEL FACTOR AND LOSS MULTIPLIERS

The Texas retail fixed fuel factor is $0.0522110 per kWh.

The loss multipliers by voltage level are:

Delivery Voltage	Loss Multiplier
Secondary	1.023660
Primary	0.996277
69kV/138kV	0.966239
230kV	0.954585

The corresponding fixed fuel factors by voltage level are:

Delivery Voltage	Fixed Fuel Factor
Secondary	$0.0534463 per kWh
Primary	$0.0520166 per kWh
69kV/138kV	$0.0504483 per kWh
230kV	$0.0498398 per kWh

Independent Statistics & Analysis
U.S. Energy Information Administration

Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies

February 2020

U.S. Department of Energy
Washington, DC 20585

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the U.S. Department of Energy or other federal agencies.

Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies

To accurately reflect the changing cost of new electric power generators for AEO2020, EIA commissioned Sargent & Lundy (S&L) to evaluate the overnight capital cost and performance characteristics for 25 electric generator types. The following report represents S&L's findings. A separate EIA report, "Addendum: Updated Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity Generating Plants in the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS)," details subsequent updates to the EMM module.

The following report was accepted by EIA in fulfillment of contract number 89303019-CEI00022. All views expressed in this report are solely those of the contractor and acceptance of the report in fulfillment of contractual obligations does not imply agreement with nor endorsement of the findings contained therein. Responsibility for accuracy of the information contained in this report lies with the contractor. Although intended to be used to inform the updating of EIA's EMM module of NEMS, EIA is not obligated to modify any of its models or data in accordance with the findings of this report.

Sargent & Lundy

Capital Cost Study

Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies

Prepared for
U.S. Energy Information Administration,
an agency of the U.S. Department of Energy

Independent Statistics & Analysis
U.S. Energy Information Administration

FINAL REPORT | DECEMBER 2019

Contract No. 89303019CEI00022
SL-014940 | Project No. 13651.005

LEGAL NOTICE

This report ("Deliverable") was prepared by Sargent & Lundy, L.L.C. ("Sargent & Lundy"), expressly for the sole use of the U.S. Department of Energy – Energy Information Administration ("Client") in accordance with the agreement between Sargent & Lundy and the Client. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) Sargent & Lundy prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by Sargent & Lundy; and (3) the information and data contained in this Deliverable are time sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.

Sargent & Lundy is one of the oldest and most experienced full-service architect engineering firms in the world. Founded in 1891, the firm is a global leader in power and energy with expertise in grid modernization, renewable energy, energy storage, nuclear power, and fossil fuels. Sargent & Lundy delivers comprehensive project services—from consulting, design, and implementation to construction management, commissioning, and operations/maintenance—with an emphasis on quality and safety. The firm serves public and private sector clients in the power and energy, gas distribution, industrial, and government sectors.

55 East Monroe Street • Chicago, IL 60603-5780 USA • 312-269-2000

VERSION LOG

Version	Issue Date
Draft	June 14, 2019
Interim Final Report	August 6, 2019
Final	August 30, 2019
Final – Rev 1.	December 9, 2019

CONTENT

CONTENT

CONTENT

CONTENT

CONTENT

CONTENT

CONTENT

CONTENT

CONTENT

APPENDIXES

Appendix A. Labor Location-Based Cost Adjustments

Appendix B. Combustion Turbine Capacity Adjustments

TABLES AND FIGURES

Table or Figure Page

TABLES AND FIGURES

Table or Figure Page

TABLES AND FIGURES

TABLES AND FIGURES

ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
°F	degrees Fahrenheit
AC	alternating current
ACC	air-cooled condenser
BESS	battery energy storage system
BFB	bubbling fluidized bed
BOP	balance of plant
Btu/kWh	British thermal unit(s) per kilowatt hour
CC	combined cycle
CCS	carbon capture and sequestration
CO	carbon monoxide
CO_2	carbon dioxide
CSP	Concentrating Solar Power
CT	combustion turbine
DC	direct current
DCS	distributed control system
EIA	U.S. Energy Information Administration
EOH	equivalent operating hours
EPC	engineering, procurement, and construction
FGD	flue gas desulfurization
G&A	general and administrative costs
GSU	generator step-up transformer
HHV	higher heating value
HRSG	heat recovery steam generator

ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
Hz	hertz
kV	kilovolt(s)
kW	kilowatt(s)
kWh	kilowatt hour(s)
lb/MMBtu	pound(s) per one million British thermal units
LNB	low-NO_X burner
MVA	megavolt ampere
MW	megawatt(s)
MWh	megawatt hour(s)
NO_X	nitrogen oxide
O&M	operations and maintenance
OEM	original equipment manufacturer
OFA	overfire air
psia	pounds per square inch absolute
PV	photovoltaic
RICE	reciprocating internal combustion engine
SCADA	Supervisory Control and Data Acquisition
SCR	selective catalytic reduction
SMR	small modular reactor
SO_2	sulfur dioxide
STG	steam turbine generator
USC	ultra-supercritical
V	volt

ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
WFGD	wet flue gas desulfurization
WTG	wind turbine generator
ZLD	zero liquid discharge

Introduction

INTRODUCTION

The U.S. Energy Information Administration (EIA) retained Sargent & Lundy to conduct a study of the cost and performance of new utility-scale electric power generating technologies. This report contains our cost and performance estimates for 25 different reference technology cases. The EIA will use these estimates to improve the EIA's Electricity Market Module's ability to represent the changing landscape of electricity generation and thus better represent capital and non-fuel operating costs of generating technologies being installed or under consideration for capacity expansion. The Electricity Market Module is a submodule within the EIA's National Energy Modeling System, a computer-based energy supply modeling system used for the EIA's *Annual Energy Outlook* and other analyses.

Sargent & Lundy developed the characteristics of the power generating technologies in this study based on information about similar facilities recently built or under development in the United States and abroad. Developing the characteristics of each generating technology included the specification of representative plant sizes, configurations, major equipment, and emission controls. Sargent & Lundy's cost assessment included the estimation of overnight capital costs, construction lead times, and contingencies as well as fixed and variable operating costs. We also estimated the net plant capacity, net plant heat rates, and controlled emission rates for each technology studied. We performed our assessments with consistent estimating methodologies across all generating technologies.

COST & PERFORMANCE OF TECHNOLOGIES

The following table lists all the power generating technologies we assessed in this study.

Table 1 — List of Reference Technologies

Case No.	Technology	Description
1	650 MW Net, Ultra-Supercritical Coal w/o Carbon Capture – Greenfield	1 x 735 MW Gross
2	650 MW Net, Ultra-Supercritical Coal 30% Carbon Capture	1 x 769 MW Gross
3	650 MW Net, Ultra-Supercritical Coal 90% Carbon Capture	1 x 831 MW Gross
4	Internal Combustion Engines	4 x 5.6 MW
5	Combustion Turbines – Simple Cycle	2 x LM6000
6	Combustion Turbines – Simple Cycle	1 x GE 7FA
7	Combined-Cycle 2x2x1	GE 7HA.02
8	Combined-Cycle 1x1x1, Single Shaft	H Class
9	Combined-Cycle 1x1x1, Single Shaft, w/ 90% Carbon Capture	H-Class
10	Fuel Cell	34 x 300 kW Gross

Case No.	Technology	Description
11	Advanced Nuclear (Brownfield)	2 x AP1000
12	Small Modular Reactor Nuclear Power Plant	12 x 50-MW Small Modular Reactor
13	50-MW Biomass Plant	Bubbling Fluidized Bed
14	10% Biomass Co-Fire Retrofit	300-MW PC Boiler
15	Geothermal	Binary Cycle
16	Internal Combustion Engines – Landfill Gas	4 x 9.1 MW
17	Hydroelectric Power Plant	New Stream Reach Development
18	Battery Energy Storage System	50 MW | 200 MWh
19	Battery Energy Storage System	50 MW | 100 MWh
20	Onshore Wind – Large Plant Footprint: Great Plains Region	200 MW | 2.8 MW WTG
21	Onshore Wind – Small Plant Footprint: Coastal Region	50 MW | 2.8 MW WTG
22	Fixed-bottom Offshore Wind: Monopile Foundations	400 MW | 10 MW WTG
23	Concentrating Solar Power Tower	with Molten Salt Thermal Storage
24	Solar PV w/ Single Axis Tracking	150 MW_{AC}
25	Solar PV w/ Single Axis Tracking + Battery Storage	150 MW_{AC} Solar 50 MW | 200 MWh Storage

Acronym Definitions:

- BESS = battery energy storage system
- Btu/kWh = British thermal units per kilowatt hour
- CC = combined cycle
- CCS = carbon capture and sequestration
- CT = combustion turbine
- kW = kilowatt
- MW = megawatt
- MW_{AC} = megawatt alternating current
- MWh = megawatt hour
- PV = photovoltaic
- USC = ultra-supercritical
- WTG = wind turbine generator

As part of the technology assessment, Sargent & Lundy reviewed recent market trends for the reference technologies using publicly available sources and in-house data. We also used our extensive background in power plant design and experience in performing similar cost and performance assessments. Using a combination of public and internal information sources, Sargent & Lundy identified the representative costs and performance for the reference technologies.

COST & PERFORMANCE ESTIMATES SUMMARY

Table 2 summarizes all technologies examined, including overnight capital cost information, fixed operating and maintenance (O&M) costs, and variable non-fuel O&M costs as well as emissions estimates for new installations (in pounds per one million British thermal units [lb/MMBtu]).

Table 2 — Cost & Performance Summary Table

Case No.	Technology	Description	Net Nominal Capacity (kW)	Net Nominal Heat Rate (Btu/Kwh)	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-year)	Variable O&M Cost ($/MWh)	NOx (lb/MMBtu)	SO2 (lb/MMBtu)	CO2 (lb/MMBtu)
1	650 MW Net, Ultra-Supercritical Coal w/o Carbon Capture – Greenfield	1 x 735 MW Gross	650	8638	3676	40.58	4.50	0.06	0.09	206
2	650 MW Net, Ultra-Supercritical Coal 30% Carbon Capture	1 x 769 MW Gross	650	9751	4558	54.30	7.08	0.06	0.09	144
3	650 MW Net, Ultra-Supercritical Coal 90% Carbon Capture	1 x 831 MW Gross	650	12507	5876	59.54	10.98	0.06	0.09	20.6
4	Internal Combustion Engines	4 x 5.6 MW	21	8295	1810	35.16	5.69	0.02	0	117
5	Combustion Turbines – Simple Cycle	2 x LM6000	105	9124	1175	16.30	4.7	0.09	0.00	117
6	Combustion Turbines – Simple Cycle	1 x GE 7FA	237	9905	713	7.00	4.5	0.03	0.00	117
7	Combined-Cycle 2x2x1	GE 7HA.02	1083	6370	958	12.20	1.87	0.0075	0.00	117
8	Combined-Cycle 1x1x1, Single Shaft	H Class	418	6431	1084	14.1	2.55	0.0075	0.00	117
9	Combined-Cycle 1x1x1, Single Shaft, w/ 90% Carbon Capture	H-Class	377	7124	2481	27.6	5.84	0.0075	0.00	11.7
10	Fuel Cell	34 x 300 kW Gross	10	6469	6700	30.78	0.59	0.0002	0	117
11	Advanced Nuclear (Brownfield)	2 x AP1000	2156	10608	6041	121.64	2.37	0	0	0
12	Small Modular Reactor Nuclear Power Plant	12 x 50-MW Small Modular Reactor	600	10046	6191	95.00	3.00	0	0	0
13	50-MW Biomass Plant	Bubbling Fluidized Bed	50	13300	4097	125.72	4.83	0.08	<0.03	206
14	10% Biomass Co-Fire Retrofit	300-MW PC Boiler	30	+ 1.5%	705	25.57	1.90	0%–20%	-8%	-8%
15	Geothermal	Binary Cycle	50	N/A	2521	128.544	1.16	0	0	0

Case No.	Technology	Description	Net Nominal Capacity (kW)	Net Nominal Heat Rate (Btu/Kwh)	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-year)	Variable O&M Cost ($/MWh)	NOx (lb/MMBtu)	SO2 (lb/MMBtu)	CO2 (lb/MMBtu)
16	Internal Combustion Engines – Landfill Gas	4 x 9.1 MW	35.6	8513	1563	20.1	6.2	0.02	0	117
17	Hydroelectric Power Plant	New Stream Reach Development	100	N/A	5316	29.86	0	0	0	0
18	Battery Energy Storage System	50 MW | 200 MWh	50	N/A	1389 (347 $/kWh)	24.8	0	0	0	0
19	Battery Energy Storage System	50 MW | 100 MWh	50	N/A	845 (423 $/kWh)	12.9	0	0	0	0
20	Onshore Wind – Large Plant Footprint: Great Plains Region	200 MW | 2.82 MW WTG	200	N/A	1265	26.34	0	0	0	0
21	Onshore Wind – Small Plant Footprint: Coastal Region	50 MW | 2.78 MW WTG	50	N/A	1677	35.14	0	0	0	0
22	Fixed-bottom Offshore Wind: Monopile Foundations	400 MW | 10 MW WTG	400	N/A	4375	110	0	0	0	0
23	Concentrating Solar Power Tower	with Molten Salt Thermal Storage	115	N/A	7221	85.4	0	0	0	0
24	Solar PV w/ Single Axis Tracking	150 MW_{AC}	150	N/A	1313	15.25	0	0	0	0
25	Solar PV w/ Single Axis Tracking + Battery Storage	150 MW_{AC} Solar 50 MW | 200 MWh Storage	150	N/A	1755	31.27	0	0	0	0

Acronym Definitions:

- $/kW = dollar(s) per kilowatt
- $/kW-year = dollar(s) per kilowatt year
- $/MWh = dollar(s) per megawatt hour
- BESS = battery energy storage system
- Btu/kWh = British thermal units per kilowatt hour
- CC = combined cycle
- CCS = carbon capture and sequestration
- CO_2 = carbon dioxide
- CT = combustion turbine
- kW = kilowatt
- lb/MMBtu = pound(s) per million British thermal units
- MW = megawatt
- MW_{AC} = megawatt alternating current
- MWh = megawatt hour
- PV = photovoltaic
- USC = ultra-supercritical
- WTG = wind turbine generator

Basis of Estimates

BASIS OF ESTIMATES

BASE FUEL SELECTION

We used the following fuel specifications as a basis for the cost estimates. The tables shown below represent typical fuel specifications for coal, natural gas, and wood biomass.

Table 3 — Reference Coal Specification

Rank	Bituminous
Proximate Analysis (weight %)	
Fuel Parameter	As Received
Moisture	11.2
Ash	9.7
Carbon	63.75
Oxygen	6.88
Hydrogen	4.5
Sulfur	2.51
Nitrogen	1.25
Chlorine	0.29
HHV, Btu/lb	11,631
Fixed Carbon/Volatile Matter	1.2

HHV = higher heating value | Btu/lb = British thermal unit per pound

Table 4 — Reference Natural Gas Specification

Component		Volume Percentage	
Methane	CH_4	93.9	
Ethane	C_2H_6	3.2	
Propane	C_3H_8	0.7	
n-Butane	C_4H_{10}	0.4	
Carbon Dioxide	CO_2	1	
Nitrogen	N_2	0.8	
Total		100	
		LHV	HHV
Btu/lb		20,552	22,793
Btu/scf		939	1,040

Btu/scf = British thermal unit per standard cubic foot

Table 5 — Reference Wood Biomass Specification

Type	Woodchips
Component	Weight %
Moisture	20– 50
Ash	0.1–0.7
Carbon	32
Sulfur	0.01
Oxygen	28
Hydrogen	3.8
Nitrogen	0.1–0.3
HHV, Btu/lb	5,400–6,200

ENVIRONMENTAL COMPLIANCE BASIS

Our technology assessments selected include the best available (emissions) control technology for sulfur dioxide (SO_2), nitrogen oxide (NO_X), particulate matter, mercury, and CO_2, where applicable. Best available control technology guidelines are covered by the U.S. Clean Air Act Title 1, which promotes air quality, ozone protection, and emission limitations. The level of emission controls is based on the following best available control technology guidelines:

- Total source emissions
- Regional environmental impact
- Energy consumption
- Economic costs

Best available control technology is not the most restrictive pollution control standard since it still includes a cost-benefit analysis for technology use. Specific technologies chosen for estimation are further described in their respective cases.

COMBUSTION TURBINE CAPACITY ADJUSTMENTS

Appendix B includes combustion turbine capacity adjustments.

Adjustments for local ambient conditions were made for power plants using combustion turbines (CTs). Since CTs produce power proportional to mass flow and ambient air temperature, relative humidity, and elevation affect air density, these conditions also affect CT performance:

- Temperature affects air density in an inversely proportional relationship and effects combined-cycle (CC) plants' cooling systems, which impacts overall plant performance.
- Relative humidity affects air density in a proportional relationship. For plants with wet cooling (evaporative coolers, wet cooling towers, etc.), relative humidity and temperature determine the effectiveness of that equipment, with the highest effectiveness when the temperature is high and the relative humidity low.
- Elevation affects air pressure and density in an inversely proportional relationship, and it was calculated in this study by using elevation above sea level. This gives the average impact of air pressure on performance, ignoring the short-term effects of weather.

Temperatures and relative humidity used in this adjustment table are based on annual averages for the locations specified. An adjustment factor for the various technologies were compared across locations on a consistent basis.

CAPITAL COST ESTIMATING

Sargent & Lundy has used a top-down capital cost estimating methodology derived from parametric evaluations of costs from actual or planned projects with similar scope and configurations to the generating technology considered. We have used both publicly available information and internal sources from which to establish the cost parameters. In some cases, we have use used portions of more detailed cost estimates to adjust the parametric factors.

The capital cost estimates represent a complete power plant facility on a generic site at a non-specific U.S. location. As applicable, the basis of the capital costs is defined as all costs to engineer, procure, construct, and commission all equipment within the plant facility fence line. As described in the following section, we have also estimated location adjustments to help establish the cost impacts to project implementation in more specific areas or regions within the United States. Capital costs account for all costs incurred during construction of the power plant before the commercial online date. The capital costs are divided between engineering, procurement, and construction (EPC) contractor and owner's costs. Sargent & Lundy assumes that the power plant developer or owner will hire an EPC contractor for turnkey construction of the project. Unless noted otherwise, the estimates assume that the EPC contractor cost will include procurement of equipment, materials, and all construction labor associated with the project. The capital costs provided are overnight capital costs in 2019 price levels. Overnight capital costs represent the total cost a developer would expect to incur during the construction of a project, excluding financing costs. The capital cost breakdowns for the EPC contractor are as follows:

- The civil and structural material and installation cost includes all material and associated labor for civil and structural tasks. This includes both labor and material for site preparation, foundation, piling, structural steel, and buildings.
- The mechanical equipment supply and installation cost includes all mechanical equipment and associated labor for mechanical tasks. This includes both labor and material for equipment installation such as pumps and tanks, piping, valves, and piping specialties.
- The electrical and instrumentation and controls supply and installation includes all costs for transformers, switchgear, control systems, wiring, instrumentation, and raceway.
- The project indirect costs include engineering, construction management, and start-up and commissioning. The fees include contractor overhead costs, fees, and profit.

The owner's costs primarily consist of costs incurred to develop the project as well as land and utility interconnection costs. The owner's development costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's participation in startup and commissioning. Outside-the-fence-line costs are considered as owner's costs. These include electrical interconnection costs and natural gas interconnection and metering costs; however, these costs too are generic and based on nominal distances to substations and gas pipeline laterals. We have also assumed that no substation upgrades would be required for the electrical interconnection. Transmission costs are based on a one-mile transmission line (unless otherwise stated) with voltage ranging from 230 kilovolts (kV) to 500 kV depending on the unit capacity. Land requirements are based on typical land requirements for each technology with per-acreage costs based on a survey of typical site costs across the United States.

The overall project contingency is also included to account for undefined project scope and pricing uncertainty for both capital cost components and owner's cost components. The levels of contingency differ in some of the estimates based on the nature of the technology and the complexity of the technology implementation.

Locational Adjustments

We estimated the capital costs adjustment factors account for technology implementation at various U.S. locations. Appendix A provides locational adjustment factors.

Craft labor rates for each location were developed from the publication *RS Means Labor Rates for the Construction Industry*, 2019 edition. Costs were added to cover social security, workmen's compensation, and federal and state unemployment insurance. The resulting burdened craft rates were used to develop typical crew rates applicable to the task performed. For each technology, up to 26 different crews were used to determine the average wage rate for each location. For several technologies, relevant internal Sargent & Lundy estimates were used to further refine the average wage rate by using the weighted average based on the crew composition for the specific technology.

Sargent & Lundy used a "30 City Average" based on *RS Means Labor Rates for the Construction Industry* to establish the base location for all the technologies. We measured the wage rate factor for each location against the base rate (the "30 City Average"). The location factors were then improved by adding the regional labor productivity factor; these factors are based on the publication *Compass International Global Construction Costs Yearbook*, 2018 edition. Even though *Compass International Global Construction Costs Yearbook* provides productivity factors for some of the major metro areas in the United States, the productivity factors on the state level were mostly used to represent the typical construction locations of plants for each of the technologies. The final location factor was measured against average productivity factor, which is based on the same 30 cities that are included in the "30 City Average" wage rate.

Environmental Location Factors

Capital cost adjustment factors have also been estimated to account for environmental conditions at various U.S. locations. These environmental location factors, however, do not account for any state or local jurisdictional amendments or requirements that modify the national design codes and standards (i.e., American Society of Civil Engineers, International Building Code. Soil Site Class D for stiff soils was assumed; geotechnical investigation is required to account for site-specific soil conditions that will need to be considered during detailed design. Risk Category II was assumed for all power generating technologies. Each environmental factor was baselined, and the geometric mean was used to determine the combined environmental location factor that accounts for the wind, seismic, snow, and tsunami effects as applicable. To distribute the environmental location factor to the material costs for the civil, mechanical, electrical, carbon capture, and other works for each of the 25 cases, the factor was proportioned based on the assumed effect environmental loading would have on the works. In other words, the concrete foundations support most of the design loading; therefore, the percentage of the environmental loading factor that was distributed to the civil works was typically the highest. The distribution of the environmental loading factor was based on typical general arrangements (i.e., equipment, buildings) for each of the 25 cases.

The environmental location factor for wind is based on ASCE 7-16, and it is based on velocity pressure for enclosed, rigid buildings with flat roofs, which is the most widely used building configuration at power generating stations. The baseline was the approximate average velocity pressure for the location data set; therefore, the factor was reduced for locations lower than the average and increased for locations above the average.

The environmental location factor for seismic is based on the Seismic Design Category, which is determined based on site-specific coefficients[1] and the calculated Mapped Spectral Response or Design Spectral Acceleration. The baseline was Seismic Design Category B; therefore, the factor was reduced for Seismic Design Category A and increased for Seismic Design Category C and D. None of the locations selected were Seismic Design Category E or F due in part to the assumed soil Site Class D.

The environmental location factor for snow loading is based on an Importance Factor of 1.00. The ground snow load was determined using the ASCE 7-16 Hazard Tool; however, the value for Boise, Idaho was based on data from ASCE 7-10 because data from ASCE 7-16 was unavailable. The ground snow load for case study areas assumed 50 pounds per square foot. The baseline was the approximate average ground snow load for the location data set; therefore, the factor was reduced for locations lower than the average and increased for locations above the average.

The environmental location factor for tsunami loading is based on ASCE 7-16 methodology and an article published by *The Seattle Times* regarding the cost implications of incorporating tsunami-resistant features into the first building designed using the methodology. The environmental location factor included tsunami effects for one location: Seattle, Washington.

[1] Determined using the web interface on https://seismicmaps.org/. The Structural Engineers Association of California's and California's Office of Statewide Health Planning and Development developed this web interface that uses the open source code provided by the United States Geological Survey to retrieve the seismic design data. This website does not perform any calculations to the table values.

Additional Location Factor Considerations

Base costs for the thermal power cases were determined assuming no significant constraints with respect to available water resources, wastewater discharge requirements, and ambient temperature extremes. In areas where these constraints are expected to add significantly to the installed equipment, we applied location adjustments to the capital costs. To account for locations with limited water resources, such as California, the southwest, and the mountain west regions, air-cooled condensers are used in lieu of mechanical draft cooling towers. In regions where wastewater loads to rivers and reservoirs are becoming increasingly restricted, zero liquid discharge (ZLD) equipment is added. Zero liquid discharge wastewater treatment equipment is assumed to include reverse osmosis, evaporation/crystallization, and fractional electrode ionization. To reduce the loading for the ZLD systems, it is assumed that cases where ZLD is applied will also have equipment in place to reduce wastewater such as air-cooled condensers or cooling tower blowdown treatment systems.

To account for ambient temperature extremes, costs for boiler enclosures have been included as part of the location factors in areas where ambient temperatures will be below freezing for significant periods of time. Costs for boiler enclosures are applied to the coal-fired cases and the biomass cases, but not to the CC heat recovery steam generators, which are assumed to open in all regions. It is assumed that the steam turbine generator (STG) equipment will be enclosed for all cases in all locations.

OPERATING & MAINTENANCE COST ESTIMATING

Once a plant enters commercial operation, the plant owners incur fixed O&M as well as variable O&M costs each year. Operations and maintenance costs presented in this report are non-fuel related.

Fixed O&M costs include costs directly related to the equipment design including labor, materials, contract services for routine O&M, and administrative and general costs. Not included are other fixed operating costs related to the location, notably property taxes and insurance. Labor, maintenance, and minor repairs and general and administrative (G&A) costs were estimated based on a variety of sources including actual projects, vendor publications, and Sargent & Lundy's internal resources. Variable O&M costs, such as ammonia, water, and miscellaneous chemicals and consumables, are directly proportional to the plant generating output.

Fixed O&M

Fixed O&M costs are those incurred at a power plant which do not vary with generation. Fixed O&M typically includes the following expenses:

- Routine Labor
- Materials and Contract Services
- Administrative and General Expenses

Routine labor includes the regular maintenance of the equipment as recommended by the equipment manufacturers. This includes maintenance of pumps, compressors, transformers, instruments, controls, and valves. The power plant's typical design is such that routine labor activities do not require a plant outage.

Materials and contract services include the materials associated with the routine labor as well as contracted services such as those covered under a long-term service agreement, which has recurring monthly payments.

General and administrative expenses are operation expenses, which include leases, management salaries, and office utilities.

For the hydro, solar, wind, and battery energy storage cases, all O&M costs are treated as fixed costs.

Variable O&M

Variable O&M costs are generation-based costs that vary based on the amount of electrical generation at the power plant. These expenses include water consumption, waste and wastewater discharge, chemicals such as selective catalytic reduction ammonia, and consumables including lubricants and calibration gas.

Cases

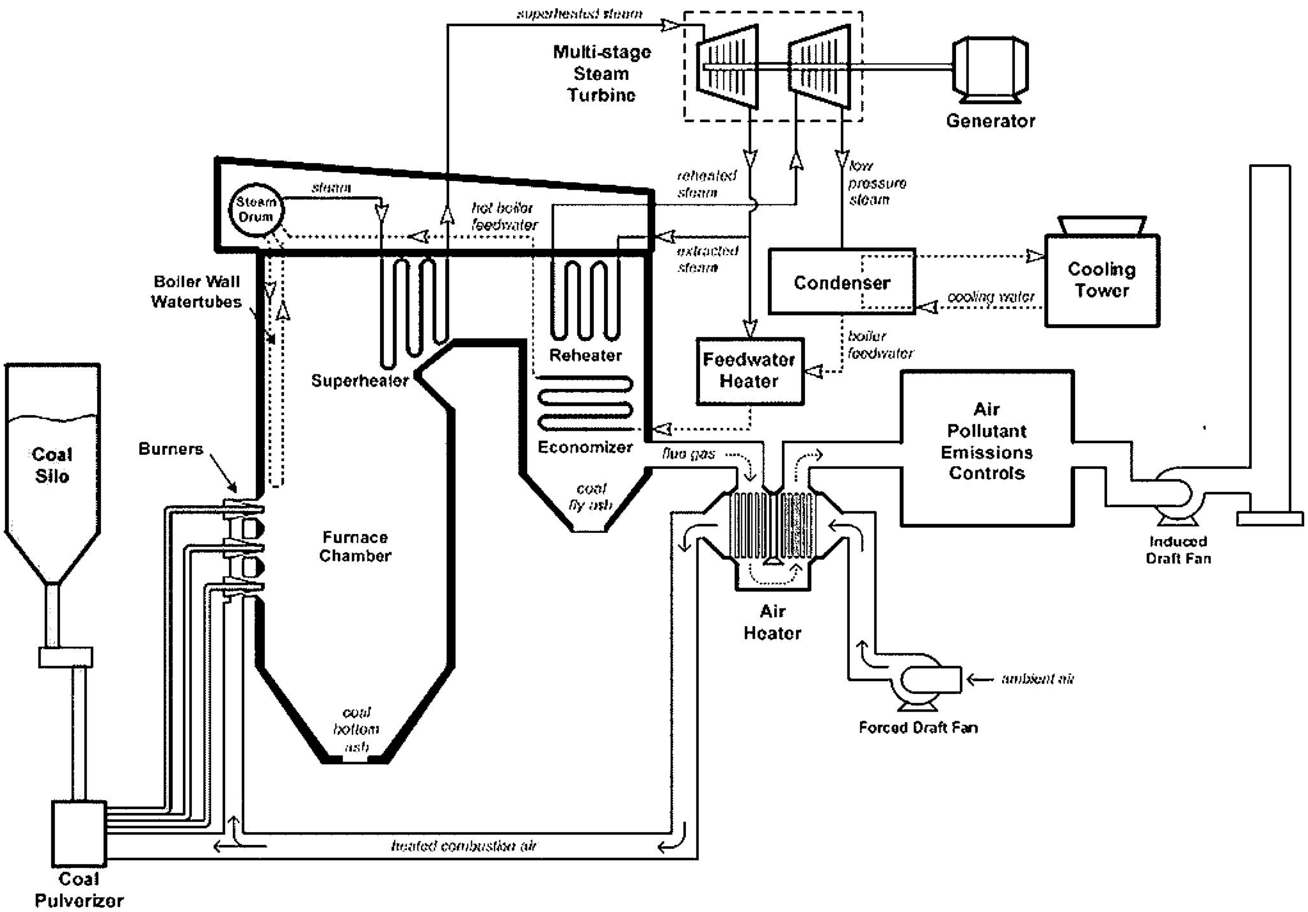
CASE 1. ULTRA-SUPERCRITICAL COAL WITHOUT CO_2 CAPTURE, 650 MW

1.1 CASE DESCRIPTION

This case comprises a coal-fired power plant with a nominal net capacity of 650 megawatts (MW) with a single steam generator and steam turbine with coal storage and handling systems, balance-of-plant (BOP) systems, and emissions control systems; there are no carbon dioxide (CO_2) capture systems. This case employs a modified Rankine cycle, referred to as an ultra-supercritical (USC) thermal cycle, which is characterized by operation at supercritical pressures at approximately 3750 psia[2] and at steam temperatures above 1100°F (degrees Fahrenheit). This increase in steam pressure and steam temperature provides more energy per pound of fuel that can be converted to shaft power in the steam turbine. The USC steam cycles are a significant improvement from the more common subcritical cycles. USC technology, therefore, represents the most efficient steam cycle currently available. These higher efficiency boilers and turbines require less coal and consequently produce less greenhouse gases and lower emissions. Throughout the past decade, many USC coal plants have been placed in operation, although most of these facilities have been constructed in Europe and Asia. Figure 1-1 is a view of the first U.S. USC coal facility, which began operation in 2012.

[2] Pounds per square inch absolute

Figure 1-1 — USC Coal Boiler – Flow Diagram



Source: U.S. Environmental Protection Agency,
Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units PDF
Accessed from EPA.gov, https://www.epa.gov/sites/production/files/2015-12/documents/electricgeneration.pdf (accessed on July 8, 2019).

The base configuration used for the cost estimate is a single unit station constructed on a greenfield site of approximately 300 acres with rail access for coal deliveries. The facility has a nominal net generating capacity of 650 MW and is assumed to fire a high sulfur bituminous coal (approximately 4 MMBtu/hour SO_2) with fuel moisture at 11% to 13% by weight and ash at 9% to 10%. Mechanical draft cooling towers are used for cycle cooling, and the water used for cycle cooling and steam cycle makeup is provided by an adjacent fresh water reservoir or river.

1.1.1 Mechanical Equipment & Systems

1.1.1.1 USC Steam Cycle

The steam turbine is a tandem compound reheat machine consisting of a high-pressure turbine, an intermediate-pressure turbine, and two double-flow low-pressure turbines with horizontal casing splits. The USC thermal cycle comprises eight feedwater heaters, with the eighth heater supplied with extraction steam from the high-pressure turbine. This heater configuration is commonly referred to as a “HARP” system, which is a Heater Above Reheat Point of the turbine steam flow path. Boiler feedwater is pressured with a single high-pressure boiler feedwater pump, which is driven with an electric motor. (For the larger boiler size described in the 90% carbon capture case [Case 3], the boiler feedwater pump is steam turbine driven, with the turbine exhaust directed to the low-pressure condenser). Steam leaves the boiler to a high-pressure steam turbine designed for the USC pressures and temperatures. Steam leaving the high-pressure turbine is reheated in the boiler and directed to the intermediate-pressure turbine. The low-pressure turbine sections are twin dual flow turbines. The condensers are multi-flow units, one per each dual flow low-pressure turbine, operated at 2.0 inches of mercury absolute. The plant cooling system uses mechanical draft cooling towers with a circulated water temperature rise of 20°F.

The plant performance estimate is based on ambient conditions of 59°F, 60% relative humidity, and sea level elevation. The boiler efficiency is assumed to be 87.5%. The gross plant output is estimated to be 735 MW with a net output of 650 MW. The net heat rate is estimated to be 8638 Btu/kWh (British thermal unit per kilowatt hour) based on the higher heating value (HHV) of the fuel and the net electrical output.

1.1.1.2 Steam Generator

For the base case design, the single steam generator is designed for an outdoor location. The steam generator is a USC, pulverized-coal-fired type, balanced draft, once-through unit equipped with superheater, reheater, economizer, and regenerative air heaters. All materials of construction are selected to withstand the pressures and temperatures associated with the USC conditions are in accordance with Section 1 of the ASME BPVC. The boiler is fired with pulverized bituminous coal through six pulverizers. The boiler-firing system consists of low-nitrogen oxide (NO_X) burners (LNBs) and overfire air (OFA). A submerged flight conveyor system is used for bottom ash removal. An economizer preheats the feedwater prior to entering the boiler water walls. Combustion air is preheated with two parallel trisector air preheaters. Combustion air is delivered to the boiler by two forced draft fans and two primary air fans. Two axial induced draft fans are used to transfer combustion gases through a baghouse, wet flue gas desulfurization (WFGD) system, and wet chimney.

1.1.1.3 Water Treatment

The facility's water treatment plant consists of pretreatment and demineralization. All raw water entering the facility is first sent to the pretreatment system, which mainly consists of two redundant clarifiers where chemicals are added for disinfection and suspended solids removal. The pretreatment system includes lime addition, allowing for the partial removal of hardness and alkalinity from the raw water if required. After pretreatment, the water is sent to a storage tank and then directed to the service and firewater users. A demineralizer system is used to provide steam cycle makeup water of sufficient quality for the once-through system. All wastewater from the demineralizer system is either recycled to the WFGD system or sent to the wastewater neutralization and discharge system.

1.1.1.4 Material Handling

The coal handling system includes rail car unloading, reclaim systems, dual coal conveyor system, transfer towers, and coal crushers. The fly ash handling system includes equipment to remove ash from the boiler, economizer, air heater, and baghouse. Fly ash is collected dry and conveyed to a storage silo. Fly ash is collected from the storage by truck for offsite disposal.

1.1.2 Electrical & Control Systems

The USC facility generator is rated at approximately 780 megavolt-ampere (MVA) with an output of 24 kilovolts (kV) and is connected via generator circuit breakers to a generator step-up transformer (GSU). The GSU increases the voltage from the generator voltage level to the transmission system high-voltage level. The electrical system includes auxiliary transformers and reserve auxiliary transformers. The facility and most of the subsystems are controlled using a central distributed control system (DCS).

1.1.3 Offsite Requirements

Coal is delivered to the facility by rail. The maximum daily coal rate for the facility is approximately 4600 tons per day. The approximate number of rail cars to support this facility is estimated at approximately 330 rail cars per week.

The site is assumed to be located adjacent to a river or reservoir that can be permitted to supply a sufficient quantity of cooling water. The total volume of water required for cooling tower makeup, cycle makeup, and other demands is estimated to be approximately 7,000 gallons per minute. Wastewater is sent to the adjacent waterway from one or more outfalls from a water treatment pond or wastewater treatment system.

The facility is assumed to start up on natural gas; therefore, the site is connected to a gas distribution system. Natural gas interconnection costs are based on a new lateral connected to existing gas pipeline.

The electrical interconnection costs are based on a one-mile distance from the facility switchyard to the terminal point on an existing utility substation. For the purposes of this estimate, the cost associated with the expansion of the substation is excluded.

1.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $3676/kilowatt (kW). Table 1-1 summarizes the cost components for this case. The basis of the estimate assumes that the site is constructed in a United States region that has good access to lower-cost construction labor and has reasonable access to water resources, coal, natural gas, and existing utility transmission substations or existing transmission lines. The geographic location is assumed to be characterized by seismic, wind, and other loading criteria that do not add significantly to the capital costs. An outdoor installation is assumed, meaning that the boiler building is not enclosed, and no special systems are needed to prevent freezing or to account for snow loads on structures.

To determine the capital costs adjustments in other United States regions where the assumptions listed above are not applicable, location factors have been calculated to account for variations in labor wage rates and access to construction labor, labor productivity, water and wastewater resource constraints, wind and seismic criteria, and other environmental criteria.

To account for locations where water resources are limited, such as California, the southwest and the mountain west regions, air-cooled condensers (ACCs) are used in lieu of mechanical draft cooling towers. In regions where wastewater loads to rivers and reservoirs are becoming increasingly restricted, zero liquid discharge (ZLD) equipment is added. Zero liquid discharge wastewater treatment equipment is assumed to include reverse osmosis, evaporation/crystallization, and fractional electrode ionization. To reduce the loading for the ZLD systems, it is assumed that cases where ZLD is applied will also have equipment in place, such as ACCs or cooling tower blowdown treatment systems, to reduce wastewater.

To account for ambient temperature extremes, costs for boiler enclosures have been included as part of the location factors in areas where ambient temperatures will be below freezing for significant periods of time. It is assumed that the STG equipment will be enclosed in all locations.

Table 1-1 — Case 1 Capital Cost Estimate

Case 1 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**650 MW Net Ultra-Supercritical Coal w/o Carbon Capture – Greenfield** 1 x 735 MW Gross	
Combustion Emissions Controls		Low NOx Burners / OFA	
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP	
Fuel Type		High Sulfur Bituminous	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	650	
Heat Rate, HHV Basis	Btu/kWh	8638	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	12%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	300	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	2,520,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,500,000	
Miles	miles	0.50	
Metering Station	$	3,600,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	36	
Total Lead Time Before COD	months	60	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		235,200,000
Mechanical – Boiler Plant	$	905,100,000	
Mechanical – Turbine Plant	$	155,200,000	
Mechanical – Balance of Plant	$	19,300,000	
Mechanical Subtotal	$		1,079,600,000
Electrical – Main Power System	$	18,100,000	
Electrical – Aux Power System	$	22,800,000	
Electrical – BOP and I&C	$	104,900,000	
Electrical – Substation and Switchyard	$	15,100,000	
Electrical Subtotal	$		160,900,000
Project Indirects	$		323,200,000
EPC Total Before Fee	$		1,798,900,000
EPC Fee	$		179,890,000
EPC Subtotal	$		1,978,790,000

Case 1 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**650 MW Net Ultra-Supercritical Coal w/o Carbon Capture – Greenfield** 1 x 735 MW Gross
Combustion Emissions Controls		Low NOx Burners / OFA
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP
Fuel Type		High Sulfur Bituminous
	Units	
Owner's Cost Components (Note 2)		
Owner's Services	$	138,515,000
Land	$	9,000,000
Electrical Interconnection	$	2,520,000
Gas Interconnection	$	4,850,000
Owner's Cost Subtotal	$	154,885,000
Project Contingency	$	256,041,000
Total Capital Cost	**$**	2,389,716,000
	$/kW net	**3,676**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.		

1.3 O&M COST ESTIMATE

The operating and maintenance costs for the USC coal-fired power generation facility are summarized in Table 1-2. The fixed costs cover the operations and maintenance (O&M) labor, contracted maintenance services and materials, and general and administrative (G&A). Major overhauls for the facility are generally based on a three-year/six-year basis depending on the equipment. Major steam turbine maintenance work is generally performed on a five- to six-year cycle, while shorter outages (e.g., change out selective catalytic reduction [SCR] catalyst) are generally performed on a three-year cycle.

Non-fuel variable costs for this technology case include flue gas desulfurization (FGD) reagent costs, SCR catalyst replacement costs, SCR reagent costs, water treatment costs, wastewater treatment costs, fly ash and bottom ash disposal costs, bag replacement for the fabric filters, and FGD waste disposal costs.

Table 1-2 — Case 1 O&M Cost Estimate

Case 1 EIA – Non-Fuel O&M Costs – 2019 $S		
650 MW Net, Ultra-Supercritical Coal w/o Carbon Capture – Greenfield		
Fixed O&M – Plant (Note 1)		
Labor	$/year	15,317,000
Materials and Contract Services	$/year	7,830,000
Administrative and General	$/year	3,233,000
Subtotal Fixed O&M	$/year	26,380,000
$/kW-year	$/kW-year	**40.58 $/kW-year**
Variable O&M (Note 2)	$/MWh	**4.50 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include catalyst replacement, ammonia, limestone, water, ash disposal, FGD waste disposal, and water discharge treatment cost.		

1.4 ENVIRONMENTAL & EMISSIONS INFORMATION

The emissions for the major criteria pollutants are summarized in Table 1-3. The NO_X emissions assume that the in-furnace controls such as LNB, OFA, and SCR systems are employed to control emissions to 0.06 pounds per one million British thermal units (lb/MMBtu). The WFGD system is assumed to be capable of 98% reduction of SO_2 from an inlet loading of 4.3 lb/MMBtu. The CO_2 emissions estimates are based on the default CO_2 emissions factors listed in Table C-1 of 40 CFR 98, Subpart C.

Table 1-3 — Case 1 Emissions

Case 1 EIA – Emissions Rates		
650 MW Net, Ultra-Supercritical Coal w/o Carbon Capture – Greenfield		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.06 (Note 2)
SO_2	lb/MMBtu	0.09 (Note 3)
CO_2	lb/MMBtu	206 (Note 4)
Emissions Control Notes		
1. High sulfur Bituminous Coal, 4.3 lb/MMBtu SO2 Coal		
2. NOx Removal using LNBs with OFA, and SCR		
3. SO2 Removal by Forced Oxidation, Limestone Based, Wet FGD, 98% Reduction		
4. Per 40 CFR 98, Subpt. C, Table C-1		

The post-combustion environmental controls for this technology case include an SCR NO_X system with aqueous ammonia as the reagent, a fabric-filter baghouse ash collection system with pulse jet cleaning, and a limestone-based forced-oxidation WFGD for the removal of SO_2 and sulfur trioxide. A wet electrostatic precipitator is included to mitigate sulfuric acid emissions. The flue gas pressure drops incurred from these backend controls have been accounted for in the induced draft fan sizing and the resultant auxiliary power demands in addition to the auxiliary power demands for the emissions control systems themselves.

For this case, no CO_2 emissions controls are assumed to be applicable. Please refer to Case 2 for 30% carbon capture and Case 3 for 90% carbon capture.

CASE 2. ULTRA-SUPERCRITICAL COAL WITH 30% CO_2 CAPTURE, 650 MW

2.1 CASE DESCRIPTION

This case comprises a coal-fired power plant with a nominal net capacity of 650 MW with a single steam generator and steam turbine with coal storage and handling systems, BOP systems, emissions control systems, and a 30% CO_2 capture system. This technology case is similar to the plant description provided in Case 1; however, this case employs CO_2 capture systems that require a larger boiler size and higher heat input to account for the low-pressure steam extraction and larger auxiliary loads needed for the CO_2 capture technology used. The CO_2 capture systems are commonly referred to as carbon capture and sequestration system (CCS) systems; however, for the cost estimates provided in this report, no sequestration costs have been included. For this case, the CO_2 captured is assumed to be compressed to supercritical conditions and injected into a pipeline terminated at the fence line of the facility. For this report, the terms "CO_2 capture" and "carbon capture" are used interchangeably.

As with Case 1, the base configuration used for the cost estimate is a single-unit station constructed on a greenfield site of approximately 300 acres with rail access for coal deliveries. The facility has a nominal net generating capacity of 650 MW and is assumed to fire a high sulfur bituminous coal with fuel moisture at 11% to 13% by weight and ash at 9% to 10%. Mechanical draft cooling towers are used for cycle cooling, and the water used for cycle cooling and steam cycle makeup is provided by an adjacent fresh water reservoir or river.

2.1.1 Mechanical Equipment & Systems

Refer to Case 1 for a description of the major mechanical equipment and systems associated with the USC power generation facility. This section provides a description of the major CO_2 capture systems used as the basis for the capital and O&M cost estimates.

2.1.1.1 General CO_2 Capture Description

The most commercially available CO_2 capture technology for coal-fired power plants is amine-based scrubbing technology. This technology requires an absorption column to absorb the CO_2 from the flue gas and a stripping column to regenerate the solvent and release the CO_2. Amine-based solvents are used in the absorption column and require periodic makeup streams and waste solvent reclamation. Steam is used to break the bond between the CO_2 and solvent. CO_2 leaves the stripper with moisture prior to being dehydrated and compressed. The product CO_2 is pipeline quality at 99.5% purity and approximately 2215 psia. The amine-based solvent systems are typically designed for 90% CO_2 capture in the absorption column.

2.1.1.2 CO_2 Capture Systems

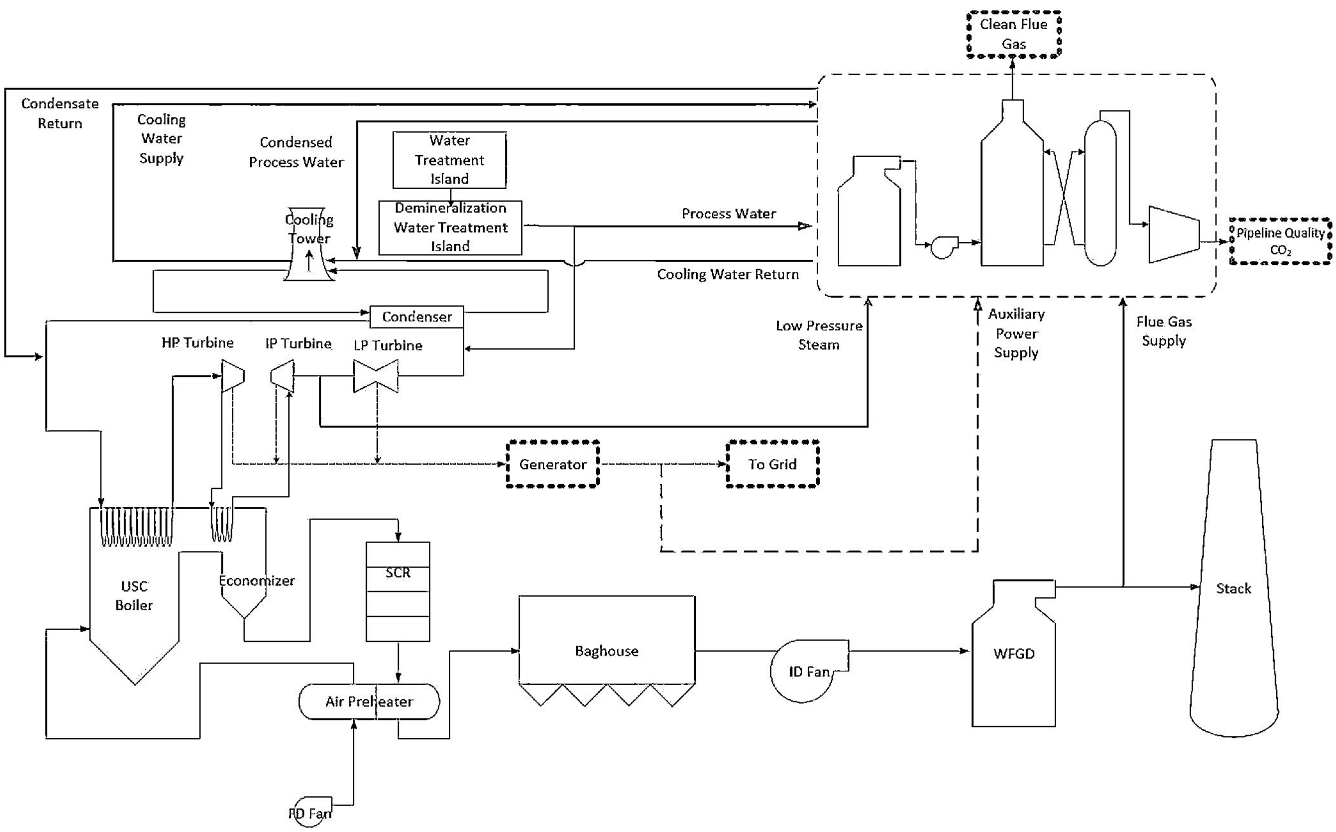
This case assumes being built with full integration to the CO_2 capture facility. The CO_2 capture technology uses various utilities to operate, including low-quality steam and auxiliary power. Steam can be extracted between the intermediate pressure and low-pressure turbine sections that will provide the least amount of capacity derate while maintaining the necessary energy to drive the CO_2 capture system. Extracting steam prior to the low-pressure turbine section requires additional fuel to be fired to account for the lost generation potential. As such, the boiler, turbine, and associated systems would be required to be made larger to maintain the same net power production. Additionally, the CO_2 capture facility and BOP associated with the CO_2 capture system requires a significant amount of auxiliary power to drive the mechanical equipment. Most of the power consumption is used to drive the CO_2 compressors to produce pipeline quality CO_2 at approximately 2215 psia. The increase in auxiliary power consumption due to the CO_2 facility usage will require a larger turbine throughput to produce the added output. Overall, CO_2 capture system integration can account for a net derate of approximately 30% in comparison with the base facility power output.

Other utilities that are integrated with the base plant are demineralized water and cooling water. Demineralized water is used to maintain a water balance within the amine process or in the solvent regeneration stages. The demineralized water consumption rate for the CO_2 capture facility is typically minor in comparison with base-plant utilization rates. As such, the demineralized water is expected to be fed from the base facility. This cost is accounted for in the O&M estimate only. Conversely, cooling water demands for the carbon capture process is significant. CO_2 capture systems require circulating cooling water rates similar to that of the condensers. As such, the cooling system, in this case evaporative cooling towers, are required to be expanded to account for the large amount of additional heat rejection. This cost is accounted for in the capital and O&M estimates. The increase in cooling tower size also requires a higher cooling tower blowdown rate that needs to be treated at the wastewater treatment system. This cost is reflected in the capital and O&M estimates.

Commercial amine-based CO_2 capture technology requires a quencher to be located upstream of the CO_2 absorber vessel. The quencher is used to cool the flue gas to optimize the kinetics and efficiency of the CO_2 absorption process via the amine-based solvent. During the quenching process, a significant amount of flue gas moisture condenses into the vessel and requires a significant amount of blowdown to maintain the level in the vessel. This blowdown quality is not good enough to reuse in the absorber system for water balance, but it is an acceptable quality to either reuse in the cooling towers or WFGD for makeup water. Due to the reuse, it does not require additional O&M costs.

A generic flow diagram for post-combustion carbon capture system is provided in Figure 2-1. The termination of the process of the CO_2 capture facility is the new emissions point, which is a small stack at the top of the CO_2 absorber vessel. For this configuration, a typical free-standing chimney is not required. Additionally, the compressed product CO_2 is the other boundary limit. This estimate does not include pipeline costs to transport the CO_2 to a sequestration or utilization site.

Figure 2-1 — Carbon Capture Flow Diagram



2.1.1.3 30% CO_2 Capture

For this technology case, the USC coal-fired facility is required to provide 30% CO_2 reduction; approximately one-third of the total flue gas must be treated. As referenced previously, 90% capture is the typical design limit for CO_2 reduction in the absorber. Therefore, 33% of the plant's flue gas would need to be treated to provide 90% reduction efficiency. A slipstream of the flue gas downstream of the

WFGD system would be extracted and sent to the CO_2 capture island. The remaining flue gas would exit through a typical free-standing wet chimney.

In this scenario, a significant amount of steam and auxiliary power is required to drive the large CO_2 capture system, ultimately increasing the size of the boiler to generate the additional steam and power required to maintain a net power output of 650 MW. As the boiler gets larger, more flue gas must be treated. As such, it is an iterative process to determine the new boiler size necessary to treat 33% of the flue gas from a new USC coal-fired boiler. Ultimately, the boiler would be built with a larger heat input than the non-CO_2 capture cases; however, the increase in size would be much less than the 90% capture case.

2.1.1.4 Plant Performance

The plant performance estimate is based on ambient conditions of 59°F, 60% relative humidity, sea level elevation, and 30% CO_2 capture. Approximately 790,000 pound per hour of low-pressure steam is required for the CO_2 system. While the boiler efficiency is assumed to be 87.5%, the estimated gross size of the steam generator is approximately 827 MW, which is approximately 13% larger than the case without carbon capture (Case 1). The estimated total auxiliary load for the plant is 119.5 MW with 28 MW required for the CO_2 system. The net heat rate is estimated to be 9751 Btu/kWh based on the HHV of the fuel and the net electrical output.

2.1.2 Electrical & Control Systems

The electrical equipment includes the turbine generator, which connects via generator circuit breakers to a GSU. The GSU increases the voltage from the generator voltages level to the transmission system high-voltage level. The electrical system is essentially similar to the USC case without carbon capture (Case 1); however, there are additional electrical transformers and switchgear for the CO_2 capture systems. The electrical system includes auxiliary transformers and reserve auxiliary transformers. The facility and most of the subsystems are controlled using a central DCS.

2.1.3 Offsite Requirements

Coal is delivered to the facility by rail. The maximum daily coal rate for the facility is approximately 5200 tons per day. The approximate number of rail cars to support this facility is estimated at approximately 360 rail cars per week.