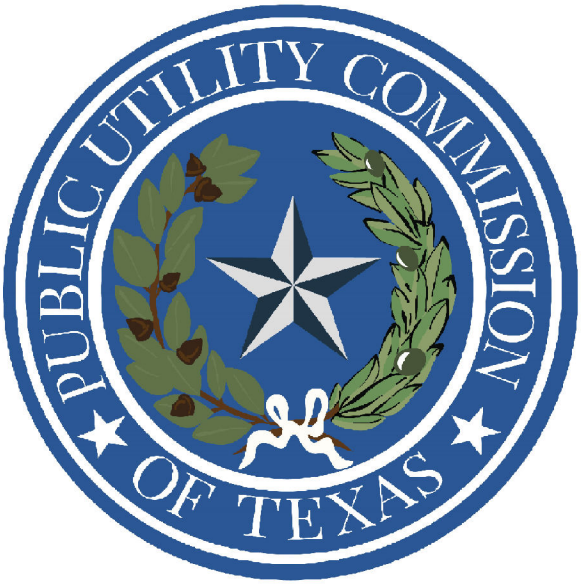

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SOAH DOCKET NO. 473-22-04394
PUC DOCKET NO. 53719

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

RESPONSE OF ENTERGY TEXAS, INC.
TO TIEC'S TENTH REQUEST FOR INFORMATION:
TIEC 10:1 THROUGH 17

Entergy Texas, Inc. ("ETI" or the "Company") files its Response to TIEC's Tenth Request for Information. The response to such request is attached and is numbered as in the request. An additional copy is available for inspection at the Company's office in Austin, Texas.

ETI believes the foregoing response is correct and complete as of the time of the response, but the Company will supplement, correct or complete the response if it becomes aware that the response is no longer true and complete, and the circumstance is such that failure to amend the answer is in substance misleading. The parties may treat this response as if it were filed under oath.

Respectfully submitted,

Kristen F. Yates

Kristen Yates
ENTERGY SERVICES, LLC
919 Congress Avenue, Suite 701
Austin, Texas 78701
Office: (512) 487-3962
Facsimile: (512) 487-3958

Attachments: **TIEC 10:1 THROUGH 17**

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Response of Entergy Texas, Inc. to TIEC's Tenth Request for Information has been sent by either hand delivery, electronic delivery, facsimile, overnight delivery, or U.S. Mail to the party that initiated this request in this docket on this the 2nd day of December 2022.

Kristen F. Yates
Kristen Yates

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc.	Prepared By: Jess K. Totten, Richard D. Starkweather, Gregory S. Wilson, Ann E. Bulkley, Sean C. McHone, Dane A. Watson
to the Tenth Set of Data Requests	Sponsoring Witnesses: Jess K. Totten, Richard D. Starkweather, Gregory S. Wilson, Ann E. Bulkley, Sean C. McHone, Dane A. Watson
of Requesting Party: Texas Industrial Energy Consumers	Beginning Sequence No. LR935
	Ending Sequence No. LR936

Question No.: TIEC 10-1 Part No.: Addendum:

Question:

To the extent not previously provided, for Mr. Starkweather, Ms. Bulkley, Mr. Wilson, Mr. McHone, Mr. Watson, and Mr. Totten, please provide all documents provided to, reviewed by, or prepared by or for the testifying expert in anticipation of the expert's rebuttal testimony in this proceeding that are not communications between counsel and expert witnesses except as provided for in Texas Rule of Civil Procedure 195.5(c).

Response:

Richard D. Starkweather response:

Mr. Starkweather has not been provided, has not reviewed, and has not prepared any documents in anticipation of his rebuttal testimony in this proceeding that have not already been filed or referenced as publicly available in this proceeding.

Jess K. Totten response:

Please see attachments (TP-53719-00TIEC010-X001-001 through TP-53719-00TIE010-X001-012).

Gregory S. Wilson response:

Mr. Wilson has not been provided, has not reviewed, and has not prepared any documents in anticipation of his rebuttal testimony in this proceeding that have not already been filed or referenced as publicly available in this proceeding.

Ann E. Bulkley Response:

Ms. Bulkley has not been provided, has not reviewed, and has not prepared any documents in anticipation of her rebuttal testimony in this proceeding that have not already been filed or referenced as publicly available in this proceeding.

Sean C. McHone response:

Mr. McHone has not been provided, has not reviewed, and has not prepared any documents in anticipation of his rebuttal testimony in this proceeding that have not already been filed or referenced as publicly available in this proceeding.

Dane A. Watson response:

Mr. Watson has not been provided, has not reviewed, and has not prepared any documents in anticipation of his rebuttal testimony in this proceeding that have not already been filed or referenced as publicly available in this proceeding.

legislature here, while investing the city with the authority to determine it, in each instance, has carefully circumscribed the power by limiting its exercise within a definitely restricted area. The city may take less than this area, but cannot take more.

The decree of the state court is

Affirmed.

BLUEFIELD WATER WORKS & IMPROVEMENT COMPANY *v.* PUBLIC SERVICE COMMISSION OF THE STATE OF WEST VIRGINIA ET AL.

ERROR TO THE SUPREME COURT OF APPEALS OF THE STATE OF WEST VIRGINIA.

No. 256. Argued January 22, 1923.—Decided June 11, 1923.

1. A judgment of the highest court of a State which upholds an order of a state commission fixing the rates of a public utility company over the objection that the rates are confiscatory and the order hence violative of the Fourteenth Amendment, is reviewable here, on the constitutional question, by writ of error. P. 683.
2. In estimating the value of the property of a public utility corporation, as a basis for rate regulation, evidence of present reproduction costs, less depreciation, must be given consideration. P. 689. *Southwestern Bell Telephone Co.* v. *Public Service Commission, ante,* 276.
3. A public utility corporation, challenging as confiscatory rates imposed by a state commission, is entitled, under the due process clause of the Fourteenth Amendment, to the independent judgment of the court as to both law and facts. *Id.*
4. Rates which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being used to render the service of the utility to the public, are unjust, unreasonable and confiscatory; and their enforcement deprives the public utility company of its property, in violation of the Fourteenth Amendment. P. 690.
5. A public utility is entitled to such rates as will permit it to earn a return on the value of the property it employs for the convenience of the public equal to that generally being made at the same time, and in the same region of the country, on investments

in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. P. 692.

6. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain its credit, and enable it to raise the money necessary for the proper discharge of its public duties. *Id.*

7. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. *Id.*

8. In this case, 6% was inadequate to constitute just compensation. P. 695.

89 W. Va. 736, reversed.

ERROR to a judgment of the Supreme Court of Appeals of West Virginia, sustaining an order of a state commission fixing water rates, in a suit brought by the plaintiff in error to set the order aside.

Mr. Alfred G. Fox, with whom *Mr. Joseph M. Sanders* was on the briefs, for plaintiff in error.

Mr. Russell S. Ritz for defendants in error.

The judgment of the Supreme Court of Appeals of West Virginia herein does not declare valid any statute of the State or any authority exercised under the State, which is repugnant to the Constitution, treaties, or laws of the United States.

The most that can be claimed is that the Commission, acting under lawful authority in reaching the conclusion from a disputed state of facts, found and fixed the value of plaintiff's property for rate making purposes at an amount less than some other tribunal may have fixed and determined from a like state of facts. A judgment based upon such a state of facts does not raise such a federal question as gives a right of review from this Court to the highest court of the State by a writ of error.

The Public Service Commission and the Supreme Court of Appeals acted under valid state authority. The authority or law under which these respective tribunals exercised jurisdiction not being repugnant to any federal law, what conclusions they may have reached from a given state of facts which furnishes the basis for the judgment complained of herein, does not present a question subject to be reviewed by writ of error. Such questions can be reviewed only on petition for a writ of certiorari. *Zucht* v. *King,* 260 U. S. 174; *Stadelman* v. *Miner,* 246 U. S. 544; *Philadelphia & Reading Coal Co.* v. *Gilbert,* 245 U. S. 162; *Ireland* v. *Woods,* 246 U. S. 323.

It is not here contended that a public utility is not entitled to a fair return upon the fair and reasonable value of all of its plant and property then used and useful in the public service, but we submit that the fair and reasonable value of a public utility's plant and property is not to be ascertained by adopting only one method of valuation to the exclusion of all other known methods and elements of value. A valuation of a public utility, such as would be fair to the public as well as the utility, should take into consideration the original cost or investment in the utility; the market value of its stocks or bonds, if any; the probable earning capacity of the property; the various rates it has received and the rate it is receiving; the amounts necessary to meet operating expenses; the ability of the utility to adequately perform the public service; the history of the operations of the utility; and perhaps other elements; and after taking all of these into consideration, fix a value that will be fair both to the public and to the utility. *Smyth* v. *Ames,* 169 U. S. 466; *San Diego Land & Town Co.* v. *Jasper,* 189 U. S. 439; *San Diego Land & Town Co.* v. *National City,* 174 U. S. 739; *Knoxville* v. *Knoxville Water Co.,* 212 U. S. 1; *Des Moines Gas Co.* v. *Des Moines,* 238 U. S. 153; *Willcox* v. *Consolidated Gas Co.,* 212 U. S. 19.

If by taking one element or method of value a conclusion is reached which is out of all proportion with a conclusion that may be reached by taking other methods, then that measure or method should be adopted which will, after taking into consideration all of the elements of value, make a fair and reasonable value on the utility's property, used and useful in the public service.

The reproduction theory of public utility valuation has been usually resorted to by the public to safeguard itself against values of public utilities, based upon inflated and watered stock investments, purporting to represent original cost. Practically all, if not all, of the decisions of this Court, in which this theory of valuation was even considered, were cases of this character; and even in them this Court has never held that the reproduction new theory at present prices was an exclusive method by which public utility values are to be determined. *Smyth* v. *Ames, supra;* Whitten, Valuation Public Service Corporations, c. V, p. 82, et seq.; 2 Wyman, Public Service Corporations, c. 32; *Coal & Coke Ry. Co.* v. *Conley,* 67 W. Va. 129; *Minnesota Rate Cases,* 230 U. S. 352.

If determining public utility values for rate-making purposes is to be accomplished by using the reproduction new theory at present prices, to the exclusion of every other element and method of values, then it may well be seen to what uncertain, as well as unfair, consequences it may lead. If the market is abnormally low and a valuation on this theory is made at such a time, without taking into consideration past costs or other elements of value, it would be manifestly unfair to the utility. Likewise, if this theory of valuation is used at a time of abnormally high prices in the market, such as was produced by the World War, and all other methods and elements of values are excluded, then it would be most unfair to the public, who would be expected to pay rates

of return upon such unfair value so reached. *Potomac Electric Power Co.* v. *Public Utilities Comm.*, 276 Fed. 330; *New York Pub. Serv. Comm.* No. 5, P. U. R. 930; *Newton* v. *Consolidated Gas Co.*, 258 U. S. 165.

MR. JUSTICE BUTLER delivered the opinion of the Court.

Plaintiff in error is a corporation furnishing water to the city of Bluefield, West Virginia, and its inhabitants. September 27, 1920, the Public Service Commission of the State being authorized by statute to fix just and reasonable rates, made its order prescribing rates. In accordance with the laws of the State (§ 16, c. 15–0, Code of West Virginia) the company instituted proceedings in the Supreme Court of Appeals to suspend and set aside the order. The petition alleges that the order is repugnant to the Fourteenth Amendment, and deprives the company of its property without just compensation and without due process of law and denies it equal protection of the laws. A final judgment was entered denying the company relief and dismissing its petition. The case is here on writ of error.

1. The city moves to dismiss the writ of error for the reason, as it asserts, that there was not drawn in question the validity of a statute or an authority exercised under the State, on the ground of repugnancy to the Federal Constitution.

The validity of the order prescribing the rates was directly challenged on constitutional grounds, and it was held valid by the highest court of the State. The prescribing of rates is a legislative act. The commission is an instrumentality of the State, exercising delegated powers. Its order is of the same force as would be a like enactment by the legislature. If, as alleged, the prescribed rates are confiscatory, the order is void. Plaintiff in error is entitled to bring the case here on writ of error and to have that question decided by this Court. The motion to dismiss will be denied. See *Oklahoma Natural Gas Co.* v.

Russell, 261 U. S. 290, and cases cited; also *Ohio Valley Water Co.* v. *Ben Avon Borough,* 253 U. S. 287.

2. The commission fixed $460,000 as the amount on which the company is entitled to a return. It found that under existing rates, assuming some increase of business, gross earnings for 1921 would be $80,000 and operating expenses $53,000, leaving $27,000, the equivalent of 5.87 per cent., or 3.87 per cent. after deducting 2 per cent. allowed for depreciation. It held existing rates insufficient to the extent of $10,000. Its order allowed the company to add 16 per cent. to all bills, excepting those for public and private fire protection. The total of the bills so to be increased amounted to $64,000. That is, 80 per cent. of the revenue was authorized to be increased 16 per cent., equal to an increase of 12.8 per cent. on the total,—amounting to $10,240.

As to value. The company claims that the value of the property is greatly in excess of $460,000. Reference to the evidence is necessary. There was submitted to the commission evidence of value which it summarized substantially as follows:

a. Estimate by company's engineer on basis of reproduction new, less depreciation, at prewar prices.....	$624,548.00
b. Estimate by company's engineer on basis of reproduction new, less depreciation, at 1920 prices.....	$1,194,663.00
c. Testimony of company's engineer fixing present fair value for rate making purposes.....	$900,000.00
d. Estimate by commission's engineer on basis of reproduction new, less depreciation at 1915 prices, plus additions since December 31, 1915, at actual cost, excluding Bluefield Valley Water Works, water rights and going value	$397,964.38

e. Report of commission's statistician showing investment cost less depreciation $365, 445. 13

f. Commission's valuation, as fixed in Case No. 368 ($360,000) plus gross additions to capital since made ($92,520.53) $452, 520. 53

It was shown that the prices prevailing in 1920 were nearly double those in 1915 and prewar time. The company did not claim value as high as its estimate of cost of construction in 1920. Its valuation engineer testified that in his opinion the value of the property was $900,000,—a figure between the cost of construction in 1920, less depreciation, and the cost of construction in 1915 and before the war, less depreciation.

The commission's application of the evidence may be stated briefly as follows:

As to "a", supra. The commission deducted $204,000 from the estimate (details printed in the margin),[1] leaving approximately $421,000 which it contrasted with the estimate of its own engineer, $397,964.38 (see *"d", supra*). It found that there should be included $25,000 for the Bluefield Valley Water Works plant in Virginia, 10 per cent. for going value, and $10,000 for working capital. If these be added to $421,000 there results $500,600. This may be compared with the commission's final figure, $460,000.

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[1] Difference in depreciation allowed $49, 000
Preliminary organization and development cost 14, 500
Bluefield Valley Water Works Plant 25, 000
Water rights 50, 000
Excess overhead costs 39, 000
Paving over mains 28, 500

[*sic*] $204, 000

As to "b" and "c", supra. These were given no weight by the commission in arriving at its final figure, $460,000. It said:

"Applicant's plant was originally constructed more than twenty years ago, and has been added to from time to time as the progress and development of the community required. For this reason, it would be unfair to its consumers to use as a basis for present fair value the abnormal prices prevailing during the recent war period, but when, as in this case, a part of the plant has been constructed or added to during that period, in fairness to the applicant, consideration must be given to the cost of such expenditures made to meet the demands of the public."

As to "d", supra. The commission taking $400,000 (round figures) added $25,000 for Bluefield Valley Water Works plant in Virginia, 10 per cent. for going value, and $10,000 for working capital, making $477,500. This may be compared with its final figure, $460,000.

As to "e", supra. The commission on the report of its statistician found gross investment to be $500,402.53. Its engineer applying the straight line method found 19 per cent. depreciation. It applied 81 per cent. to gross investment and added 10 per cent. for going value and $10,000 for working capital, producing $455,500.[2] This may be compared with its final figure, $460,000.

As to "f", supra. It is necessary briefly to explain how this figure, $452,520.53, was arrived at. Case No. 368 was a proceeding initiated by the application of the company for higher rates, April 24, 1915. The commission made a valuation as of January 1, 1915. There were presented two estimates of reproduction cost less depreciation, one by a valuation engineer engaged by the com-

[2] As to "e". $365,445.13 represents investment cost less depreciation. The gross investment was found to be $500,402.53, indicating a deduction on account of depreciation of $134,957.40, about 27 per cent. as against 19 per cent. found by the commission's engineer.

pany and the other by a valuation engineer engaged by the city, both "using the same method." An inventory made by the company's engineer was accepted as correct by the city and by the commission. The method "was that generally employed by courts and commissions in arriving at the value of public utility properties under this method", and in both estimates "five year average unit prices" were applied. The estimate of the company's engineer was $540,000 and of the city's engineer, $392,000. The principal differences as given by the commission are shown in the margin.[3] The commission disregarded both estimates and arrived at $360,000. It held that the best basis of valuation was the net investment, i. e., the total cost of the property less depreciation. It said: "The books of the company show a total gross investment since its organization, of $407,882.00, and that there has been charged off for depreciation from year to year the total sum of $83,445.00, leaving a net investment of $324,427.00. . . . From an examination of the books . . . it appears that the records of the company have been remarkably well kept and preserved. It, therefore, seems that when a plant is developed under these conditions the net investment which of course means the total gross investment less depreciation is the very best basis of valuation for rate making purposes and that the other methods above referred to should

	Company engineer.	City engineer.
1. Preliminary cost	$14,455	$1,000
2. Water rights	50,000	Nothing.
3. Cutting pavements over mains	27,744	233
4. Pipe lines from gravity springs	22,072	15,442
5. Laying cast iron street mains	19,252	15,212
6. Reproducing Ada Springs	18,558	13,027
7. Superintendence and Engineering	20,515	13,621
8. General contingent cost	16,415	5,448
	$189,011	$63,983

be used only when it is impossible to arrive at the true investment. Therefore, after making due allowance for capital necessary for the conduct of the business and considering the plant as a going concern, it is the opinion of the commission that the fair value for the purpose of determining reasonable and just rates in this case of the property of the applicant company, used by it in the public service of supplying water to the City of Bluefield and its citizens, is the sum of $360,000.00, which sum is hereby fixed and determined by the Commission to be the fair present value for the said purpose of determining the reasonable and just rates in this case."

In its report in No. 368, the commission did not indicate the amounts respectively allowed for going value or working capital. If 10 per cent. be added for the former, and $10,000 for the latter (as fixed by the commission in the present case) there is produced $366,870, to be compared with $360,000, found by the commission in its valuation as of January 1, 1915. To this it added $92,520.53 expended since, producing $452,520.53. This may be compared with its final figure, $460,000.

The State Supreme Court of Appeals holds that the valuing of the property of a public utility corporation and prescribing rates are purely legislative acts not subject to judicial review except in so far as may be necessary to determine whether such rates are void on constitutional or other grounds; and that findings of fact by the commission based on evidence to support them will not be reviewed by the court. *Bluefield* v. *Water Works Co.*, 81 W. Va. 201, 204; *Coal and Coke Co.* v. *Public Service Commission*, 84 W. Va. 662, 678; *Charleston* v. *Public Service Commission*, 86 W. Va. 536.

In this case (89 W. Va. 736) it said (p. 738):

"From the written opinion of the commission we find that it ascertained the value of the petitioner's property for rate making [then quoting the commission] 'after

maturely and carefully considering the various methods presented for the ascertainment of fair value and giving such weight as seems proper to every element involved and all the facts and circumstances disclosed by the record.'"

The record clearly shows that the commission in arriving at its final figure did not accord proper, if any, weight to the greatly enhanced costs of construction in 1920 over those prevailing about 1915 and before the war, as established by uncontradicted evidence; and the company's detailed estimated cost of reproduction new, less depreciation, at 1920 prices, appears to have been wholly disregarded. This was erroneous. *Missouri ex rel. Southwestern Bell Telephone Co.* v. *Public Service Commission, ante,* 276. Plaintiff in error is entitled under the due process clause of the Fourteenth Amendment to the independent judgment of the court as to both law and facts. *Ohio Valley Water Co.* v. *Ben Avon Borough,* 253 U. S. 287, 289, and cases cited.

We quote further from the court's opinion (pp. 739, 740):

"In our opinion the commission was justified by the law and by the facts in finding as a basis for rate making the sum of $460,000.00 . . . In our case of *Coal & Coke Ry. Co.* v. *Conley,* 67 W. Va. 129, it is said: 'It seems to be generally held that, in the absence of peculiar and extraordinary conditions, such as a more costly plant than the public service of the community requires, or the erection of a plant at an actual, though extravagant, cost, or the purchase of one at an exorbitant or inflated price, the actual amount of money invested is to be taken as the basis, and upon this a return must be allowed equivalent to that which is ordinarily received in the locality in which the business is done, upon capital invested in similar enterprises. In addition to this, consideration must be given to the nature of the investment, a higher rate

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being regarded as justified by the risk incident to a hazardous investment.' .

"That the original cost considered in connection with the history and growth of the utility and the value of the services rendered constitute the principal elements to be considered in connection with rate making, seems to be supported by nearly all the authorities."

The question in the case is whether the rates prescribed in the commission's order are confiscatory and therefore beyond legislative power. Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. This is so well settled by numerous decisions of this Court that citation of the cases is scarcely necessary. "What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience." *Smyth* v. *Ames*, (1898) 169 U. S. 466, 547.

"There must be a fair return upon the reasonable value of the property at the time it is being used for the public. . . .

"And we concur with the court below in holding that the value of the property is to be determined as of the time when the inquiry is made regarding the rates. If the property, which legally enters into the consideration of the question of rates, has increased in value since it was acquired, the company is entitled to the benefit of such increase." *Willcox* v. *Consolidated Gas Co.*, (1909) 212 U. S. 19, 41, 52.

"The ascertainment of that value is not controlled by artificial rules. It is not a matter of formulas, but there must be a reasonable judgment having its basis in a proper consideration of all relevant facts." *Minnesota Rate Cases*, (1913) 230 U. S. 352, 434.

"And in order to ascertain that value, the original cost of construction, the amount expended in permanent improvements, the amount and market value of its bonds and stock, the present as compared with the original cost of construction, the probable earning capacity of the property under particular rates prescribed by statute, and the sum required to meet operating expenses, are all matters for consideration, and are to be given such weight as may be just and right in each case. We do not say that there may not be other matters to be regarded in estimating the value of the property." *Smyth* v. *Ames, supra,* 546, 547.

". . . . The making of a just return for the use of the property involves the recognition of its fair value if it be more than its cost. The property is held in private ownership and it is that property, and not the original cost of it, of which the owner may not be deprived without due process of law." *Minnesota Rate Cases, supra,* 454.

In *Missouri ex rel. Southwestern Bell Telephone Co.* v. *Public Service Commission, supra,* applying the principles of the cases above cited and others, this Court said:

"Obviously, the Commission undertook to value the property without according any weight to the greatly enhanced costs of material, labor, supplies, etc., over those prevailing in 1913, 1914 and 1916. As matter of common knowledge, these increases were large. Competent witnesses estimated them as 45 to 50 per centum . . . It is impossible to ascertain what will amount to a fair return upon properties devoted to public service without giving consideration to the cost of labor, supplies, etc., at the time the investigation is made. An honest and intelligent forecast of probable future values made upon a view of all the relevant circumstances, is essential. If the highly important element of present costs is wholly disregarded such a forecast becomes impossible. Estimates for to-morrow cannot ignore prices of today."

It is clear that the court also failed to give proper consideration to the higher cost of construction in 1920 over that in 1915 and before the war, and failed to give weight to cost of reproduction less depreciation on the basis of 1920 prices, or to the testimony of the company's valuation engineer, based on present and past costs of construction, that the property in his opinion, was worth $900,000. The final figure, $460,000, was arrived at substantially on the basis of actual cost less depreciation plus ten per cent. for going value and $10,000 for working capital. This resulted in a valuation considerably and materially less than would have been reached by a fair and just consideration of all the facts. The valuation cannot be sustained. Other objections to the valuation need not be considered.

3. *Rate of return.* The state commission found that the company's net annual income should be approximately $37,000, in order to enable it to earn 8 per cent. for return and depreciation upon the value of its property as fixed by it. Deducting 2 per cent. for depreciation, there remains 6 per cent. on $460,000, amounting to $27,600 for return. This was approved by the state court.

The company contends that the rate of return is too low and confiscatory. What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in

highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

In 1909, this Court, in *Willcox* v. *Consolidated Gas Co.*, 212 U. S. 19, 48–50, held that the question whether a rate yields such a return as not to be confiscatory depends upon circumstances, locality and risk, and that no proper rate can be established for all cases; and that, under the circumstances of that case, 6 per cent. was a fair return on the value of the property employed in supplying gas to the City of New York, and that a rate yielding that return was not confiscatory. In that case the investment was held to be safe, returns certain and risk reduced almost to a minimum—as nearly a safe and secure investment as could be imagined in regard to any private manufacturing enterprise.

In 1912, in *Cedar Rapids Gas Light Co.* v. *Cedar Rapids*, 223 U. S. 655, 670, this Court declined to reverse the state court where the value of the plant considerably exceeded its cost, and the estimated return was over 6 per cent.

In 1915, in *Des Moines Gas Co.* v. *Des Moines*, 238 U. S. 153, 172, this Court declined to reverse the United States District Court in refusing an injunction upon the conclusion reached that a return of 6 per cent. per annum upon the value would not be confiscatory.

In 1919, this Court in *Lincoln Gas Co.* v. *Lincoln*, 250 U. S. 256, 268, declined on the facts of that case to approve a finding that no rate yielding as much as 6 per

cent. on the invested capital could be regarded as confiscatory. Speaking for the Court, Mr. Justice Pitney said:

"It is a matter of common knowledge that, owing principally to the world war, the costs of labor and supplies of every kind have greatly advanced since the ordinance was adopted, and largely since this cause was last heard in the court below. And it is equally well known that annual returns upon capital and enterprise the world over have materially increased, so that what would have been a proper rate of return for capital invested in gas plants and similar public utilities a few years ago furnishes no safe criterion for the present or for the future."

In 1921, in *Brush Electric Co.* v. *Galveston,* the United States District Court held 8 per cent. a fair rate of return.[4]

In January, 1923, in *Minneapolis* v. *Rand,* the Circuit Court of Appeals of the Eighth Circuit (285 Fed. 818, 830) sustained, as against the attack of the city on the ground that it was excessive, 7½ per cent., found by a special master and approved by the District Court as a fair and reasonable return on the capital investment—the value of the property.

Investors take into account the result of past operations, especially in recent years, when determining the terms upon which they will invest in such an undertaking. Low, uncertain or irregular income makes for low prices for the securities of the utility and higher rates of interest to be demanded by investors. The fact that the company may not insist as a matter of constitutional right that past losses be made up by rates to be applied in the present and future tends to weaken credit, and the fact that the utility is protected against being compelled to serve for confiscatory rates tends to support it. In

[4] This case was affirmed by this Court, June 4, 1923, *ante,* 443.

this case the record shows that the rate of return has been low through a long period up to the time of the inquiry by the commission here involved. For example, the average rate of return on the total cost of the property from 1895 to 1915, inclusive, was less than 5 per cent.; from 1911 to 1915, inclusive, about 4.4 per cent., without allowance for depreciation. In 1919 the net operating income was approximately $24,700, leaving $15,500, approximately, or 3.4 per cent. on $460,000 fixed by the commission, after deducting 2 per cent. for depreciation. In 1920, the net operating income was approximately $25,465, leaving $16,265 for return, after allowing for depreciation. Under the facts and circumstances indicated by the record, we think that a rate of return of 6 per cent. upon the value of the property is substantially too low to constitute just compensation for the use of the property employed to render the service.

The judgment of the Supreme Court of Appeals of West Virginia is reversed.

MR. JUSTICE BRANDEIS concurs in the judgment of reversal for the reasons stated by him in *Missouri ex rel. Southwestern Bell Telephone Co.* v. *Public Service Commission of Missouri, supra.*

CITY NATIONAL BANK OF EL PASO, TEXAS, *v.* EL PASO & NORTHEASTERN RAILROAD COMPANY ET AL.

CERTIORARI TO THE COURT OF CIVIL APPEALS, EIGHTH SUPREME JUDICIAL DISTRICT, OF THE STATE OF TEXAS.

No. 309. Argued March 12, 1923.—Decided June 11, 1923.

Where a bank was accustomed, through an agent, to make interstate shipments of cattle to another bank in care of a commission company, sending its drafts on the commission company for the pur-

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BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR APPROVAL OF A GENERAL CHANGE IN RATES AND TARIFFS	))))	**DOCKET NO. 21-070-U**

REBUTTAL TESTIMONY OF

THOMAS P. BRICE

ON BEHALF OF

SOUTHWESTERN ELECTRIC POWER COMPANY

JANUARY 13, 2022

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TESTIMONY INDEX

REBUTTAL EXHIBITS

REBUTTAL EXHIBIT	DESCRIPTION
REBUTTAL EXHIBIT TPB-1	Louisiana Public Service Commission Order No. U-30975

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Thomas P. Brice, and my position is Vice President of Regulatory and Finance for Southwestern Electric Power Company (SWEPCO or the Company). My business address is 428 Travis Street, Shreveport, Louisiana 71156.

Q. ARE YOU THE SAME THOMAS P. BRICE WHO PREVIOUSLY PROVIDED DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

II. TESTIMONY PURPOSE

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimony of the General Staff (Staff) of the Arkansas Public Service Commission (APSC or Commission), the Office of the Attorney General (AG), Western Arkansas Large Energy Consumers (WALEC), Sierra Club, and City of Fayetteville witnesses concerning the matters outlined below:

1. The reasonableness of SWEPCO's proposed depreciation treatment and recovery of any unrecovered book value associated with the Dolet Hills, Pirkey, and Welsh power plants. I will address and rebut the recommendations of Staff witness Middleton Ray, AG witness Greg R. Meyer, WALEC witness Mark Garrett, and Sierra Club witness Devi Glick that the Commission deny recovery of a return on the Company's remaining unrecovered investment in the Dolet Hills plant after its retirement. These recommendations unreasonably penalize SWEPCO for prudently retiring the plant for the benefit of its customers. I will also address certain witnesses' challenges to SWEPCO's proposed amortization schedules for these plants.

2. The reasonableness of SWEPCO's request to adopt a Formula Rate Plan (FRP) and corresponding Formula Rate Review Rider (FRR Rider). I will address

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WALEC witness Mark Garrett's claim that SWEPCO violated the parties' settlement agreement in the Company's last rate case, Docket No. 19-008-U, by withdrawing from the FRP adopted in that case. I also will address Staff witness Regina L. Butler's testimony that SWEPCO's requested FRR Rider inappropriately seeks to alter the terms of the FRR Rider agreed to and approved by the Commission in Docket No. 19-008-U. Finally, I will generally respond to AG witness Michael P. Gorman's proposed modifications to the requested FRR Rider.

3. The scope and sufficiency of SWEPCO's evidence supporting the prudence and reasonableness of its capital additions and its affiliate operations and maintenance (O&M) expenses. Specifically, I will address AG witness Scott Norwood's false and unsubstantiated claims that SWEPCO: (a) failed to provide any such evidence with its direct case; and (b) believes it is not required to provide evidence of the prudence of specific capital investments in the Arkansas jurisdiction.

4. The reasonableness of SWEPCO's evaluation and continued operation of certain coal and lignite units. Specifically, I will address the testimonies of Staff witness John G. Athas, Sierra Club witness Glick, and City of Fayetteville witness Peter Nierengarten concerning: (1) SWEPCO's operation of the Pirkey, Welsh, and Flint Creek plants; and (2) the sufficiency of the Company's unit disposition analyses prepared to evaluate compliance with the U.S. Environmental Protection Agency's (EPA) Coal Combustion Residuals (CCR) Rule and Effluent Limitations Guidelines (ELG) Rules.

5. The reasonableness of SWEPCO's five-year amortization of the Dolet Hills Lignite Company mining costs in its 2021 Energy Cost Recovery Rider (Rider ECR). I will address Staff witness Davis' recommendation that SWEPCO amortize these costs over a twenty-five year period.

Q. DOES THE FACT THAT YOU MAY NOT ADDRESS AN ISSUE OR POSITION ADVOCATED BY OTHER PARTIES INDICATE THAT YOU AGREE WITH THEIR POSITIONS?

A. No. If I do not address an issue in my testimony, it does not mean that I agree with that issue.

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III. COST RECOVERY AND DEPRECIATION TREATMENT OF CERTAIN COAL AND LIGNITE PLANTS

A. DOLET HILLS

Q. HAS ANY PARTY TO THIS PROCEEDING CHALLENGED SWEPCO'S DECISION TO RETIRE THE DOLET HILLS PLANT?

A. No. As explained in my direct testimony, SWEPCO has studied the expected total SWEPCO system cost to serve customers under the scenario where the Dolet Hills plant continues to serve customers through 2026 and the scenario where the Dolet Hills plant is retired by December 31, 2021. That study, as discussed by SWEPCO witness Joseph S. Perez, demonstrates that the expected least cost path for SWEPCO and its customers lies in the retirement of the Dolet Hills plant with an estimated total company savings of $180 million for its customers. No witness in this case challenges this analysis or the prudence of SWEPCO's decision to retire the plant.

Q. WILL THE DOLET HILLS PLANT BE FULLY DEPRECIATED AT THE TIME OF ITS RETIREMENT?

A. No.

Q. IS IT UNUSUAL FOR A POWER PLANT TO HAVE SOME UNDEPRECIATED VALUE WHEN IT IS RETIRED?

A. Not at all. A regulated utility has an obligation to serve and, consequently, must continue to invest in its generating units to ensure they can provide safe and reliable service until they are actually retired. In addition, approvals of proposed depreciation rate changes by regulatory commissions take time. As a result, I would be surprised if any generating unit is fully depreciated at retirement.

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Q. HOW IS SWEPCO PROPOSING TO RECOVER THE REMAINING UNRECOVERED BOOK VALUE OF THE DOLET HILLS PLANT?

A. To mitigate the rate impact to customers, SWEPCO is proposing that the plant's unrecovered remaining book value be transferred to a regulatory asset, and amortized and recovered in rates over a 5-year period along with a return at the Company's weighted average cost of capital (WACC).

Q. DO ANY WITNESSES OPPOSE SWEPCO'S PROPOSAL?

A. Yes. Staff witness Ray, WALEC witness Mark Garrett, AG witness Meyer, and Sierra Club witness Glick each oppose SWEPCO's proposed recovery of a return on the remaining unrecovered book value of the Dolet Hills plant because the plant will not be providing service to customers. In addition, witnesses Ray, Mark Garrett, and Meyer propose a different amortization period for SWEPCO's recovery of (but not on) its remaining investment in the Dolet Hills plant. Witnesses Ray and Mark Garrett propose a twenty-five year amortization period and Meyer proposes a ten-year amortization period.

Q. SHOULD SWEPCO BE PENALIZED FOR THE DECISION TO RETIRE THE DOLET HILLS PLANT?

A. No. There is no basis to penalize SWEPCO for making a decision that is in the best interest of customers, nor does any party directly suggest that SWEPCO should be penalized for this decision. However, the Staff and Intervenor witnesses' recommended ratemaking treatments for the Dolet Hills plant do, in fact, penalize SWEPCO for acting

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in the best interest of its customers by requiring SWEPCO to write-off a portion of its remaining, undepreciated investment in the Dolet Hills plant.

In my experience, the Commission expects utilities subject to its jurisdiction to exercise judgment and select or choose a course of action that falls within that range of actions that a reasonable utility manager would choose in the same or similar circumstances. That is exactly what SWEPCO has done here. SWEPCO recognized the changed circumstances faced by the Dolet Hills plant and made a reasonable decision to retire the plant by the end of 2021, which no party challenges.

Q. HOW MUCH WILL SWEPCO BE REQUIRED TO WRITE OFF IF THE COMMISSION ADOPTS THE RATEMAKING TREATMENTS PROPOSED BY THE STAFF AND INTERVENOR WITNESSES?

A. The following table provides the estimated amounts SWEPCO will be required to write off if the Commission denies recovery of a return on the remaining unrecovered investment in the Dolet Hills plant.

Table 1: Estimated Write Off

	Five-Year Amortization (SWEPCO)	Ten-Year Amortization (AG)	Twenty-Five Year Amortization (Staff & WALEC)
Expected Write Off (Total Company)	$6.9 Million	$13.1 Million	$29.2 Million
Expected Write Off (Arkansas Jurisdiction)	$1.4 Million	$2.6 Million	$5.8 Million

SWEPCO witness Jason Yoder addresses this issue in his Rebuttal Testimony and further explains why the write-off is required if the Staff and Intervenors' position is accepted.

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Q. DO YOU AGREE THAT IT IS UNREASONABLE FOR SWEPCO TO RECOVER A RETURN ON ITS UNRECOVERED INVESTMENT IN A PLANT THAT IS NOT PROVIDING CUSTOMERS ANY SERVICE?

A. No. This argument ignores the basic ratemaking principle, as recognized by the United States Supreme Court, that "Customers pay for service, not for the property used to render it. These payments are not contributions to depreciation or other operating expenses or to the capital of the Company."[1] In other words, customers do not directly pay for and SWEPCO does not recover costs specific to the Dolet Hills plant. Rather, customers pay for electricity based on Commission-approved rates and SWEPCO sells electricity at Commission-approved prices. Although a regulatory commission utilizes various utility costs, including power plant costs, to develop rates for customers to pay for their electricity, those rates are designed to allow a utility a reasonable opportunity to earn a reasonable return on investments after paying all of its expenses.

Q. PLEASE ADDRESS STAFF'S ASSERTION THAT ALLOWING SWEPCO TO EARN A RETURN ON THE REMAINING UNDEPRECIATED PORTION OF THE DOLET HILLS PLANT IS CONTRARY TO LONG-ESTABLISHED APSC PRECEDENT THAT ITEMS NOT USED AND USEFUL DO NOT EARN A RETURN.[2]

A. I am not a lawyer, but to my knowledge, there is no statutory directive in Arkansas prohibiting recovery of a return on an investment in a generation facility that the

[1] *Board of Pub. Util. Comm'n v. New York Tel. Co.*, 271 U.S. 23, 32 (1926).
[2] Direct Testimony of Middleton Ray at 11.

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Commission views as no longer used after retirement. Rather, the Commission is charged with ensuring that utility rates are "just and reasonable." This directive does not forbid the Commission from recognizing that there is a cost of financing investment in a generation asset that is prudently retired with undepreciated value, especially when a plant provided low cost electricity for almost 35 years. Consequently, I believe that the Commission has the authority to allow a carrying cost on this undepreciated value at SWEPCO's WACC, thereby avoiding a punitive write-down of prudently invested capital in generating plants that were prudently retired.

Q. ON PAGE 36 OF HIS TESTIMONY, MR. MARK GARRETT PROVIDES A TABLE SHOWING THAT AMERICAN ELECTRIC POWER COMPANY, INC. (AEP) RETIRED THIRTEEN COAL PLANTS IN 2015 THAT WERE NOT FULLY DEPRECIATED. THE PURPOSE OF THE TABLE, ACCORDING TO MR. MARK GARRETT, IS TO SHOW THAT THE REGULATORS IN THE JURISDICTIONS IN WHICH THOSE PLANTS OPERATED ALLOWED RECOVERY OF THE REMAINING PLANT BALANCES OVER RELATIVELY LONG AMORTIZATION PERIODS—TWENTY-FIVE TO THIRTY YEARS.[3] DOES MR. MARK GARRETT'S TABLE ADDRESS WHETHER THE REGULATORS IN THOSE JURISDICTIONS AUTHORIZED RECOVERY OF A RETURN ON THE RETIRED PLANTS' REMAINING UNRECOVERED BALANCES?

[3] Direct Testimony of Mark E. Garrett at 35-36.

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A. No. However, in each example provided by Mr. Garrett, a return on the plant's remaining balance at the applicable WACC was allowed. Below, I have reproduced the table from Mr. Mark Garrett's testimony with the addition of a column indicating which of the units identified by Mr. Mark Garrett are earning a WACC return.

Table 2: AEP's Coal Units Retired in 2015

AEP Coal Units	Retired	Amortized Through	Amortized Over	State	Balance	Earning WACC Return
Tanner Creek Unit 1[4]	2015	2044	30	Michigan	$43.401M	Y
Tanner Creek Unit 2	2015	2044	30	Michigan	$43.401M	Y
Tanner Creek Unit 3	2015	2044	30	Indiana	$43.401M	Y
Tanner Creek Unit 4	2015	2044	30	Indiana	$43.401M	Y
Big Sandy Unit 1[5]	2015	2040	25	Kentucky	$92.491M	Y
Big Sandy Unit 2	2015	2040	25	Kentucky	$92.491M	Y

[4] The amortization and recovery of the undepreciated value of the Tanners Creek units was addressed by the Indiana Utility Regulatory Commission and Michigan Public Service Commission in Cause Nos. 44555 (Indiana) and U-17524 (Michigan). *See In the Matter of the Application of Indiana Michigan Power Company for Approval of Revised Depreciation Accrual Rates for Rockport Unit 1 and Tanners Creek Generating Stations*, Cause No. U-17524, Order Approving Settlement Agreement (Sept. 26, 2014); *see also In the Matter of the Verified Petition of Indiana Michigan Power Company for Authority to Implement Revised Steam Production Depreciation Accrual Rates Applicable to its Rockport Unit 1 to Reflect a Change in the Expected Service Life of the Tanners Creek Plant and Approval of Basic Rates Adjustment through a Depreciation Credit*, Cause No. 44555, Order (May 20, 2015).

[5] The amortization and recovery of the undepreciated value of the Big Sandy units was addressed by the Kentucky Public Service Commission in Case No. 2012-00578. *See Application of Kentucky Power Company for (1) a Certificate of Public Convenience and Necessity Authorizing the Transfer to the Company of an Undivided Fifty Percent Interest in the Mitchell Generating Station and Associated Assets; (2) Approval of the Assumption by Kentucky Power Company of Certain Liabilities in the Connection with the Transfer of the Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral of Costs Incurred in Connection with the Company's Efforts to Meet Federal Clean Air Act and Related Requirements; and (5) all other Required Approvals and Relief*, Case No. 2012-00578, Order (Oct. 7, 2013).

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Table 2: AEP's Coal Units Retired in 2015

AEP Coal Units	Retired	Amortized Through	Amortized Over	State	Balance	Earning WACC Return
Kawona River Units 1-2[6]	2015	2040	25	West Virginia	$43.924M	Y
Sporn Unit 1	2015	2040	25	West Virginia	$6.982M	Y
Sporn Unit 3	2015	2040	25	West Virginia	$6.982M	Y
Glen Lyn Unit 5	2015	2040	25	West Virginia	$3.703M	Y
Glen Lyn Unit 6	2015	2040	25	West Virginia	$3.703M	Y
Clinch River Units 1-2	2015	2040	25	West Virginia	$8.211M	Y
Clinch River Units 3	2015	2040	25	West Virginia	$56.967M	Y
Total Costs					$489.065M	

Q. DO YOU HAVE ANY ADDITIONAL OBSERVATIONS ON MR. MARK GARRETT'S TABLE PRESENTED ABOVE?

A. Yes, Mr. Mark Garrett's table is inaccurate as to the amortization period of the Tanners Creek units. The initial post-retirement amortization period approved for the units ran through 2044, as shown on Mr. Mark Garrett's table. However, this period has since been reduced to provide for the amortization of the remaining balance of the units through 2028. The applicable AEP operating company is still earning a WACC, even with this shorter recovery period.

[6] The amortization and recovery of the undepreciated value of the Sporn, Glen Lyn, and Clinch River units was addressed by the Public Service Commission of West Virginia in Case No. 14-1151-E-D. *See Appalachian Power Co. & Wheeling Power Co., both d/b/a American Elec. Power*, Case Nos. 14-1152-E-42T and 14-1151-E-D, Commission Order on the Tariff Filing Appalachian Power Co. and Wheeling Power Co. to Increase Rates and Petition to Change Depreciation Rates (May 26, 2015).

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Q. MR. MARK GARRETT CLAIMS THAT THE OKLAHOMA CORPORATION COMMISSION (OCC) HAS ADOPTED THE TEXAS RATE TREATMENT FOR RETIRED PLANTS WITH REMAINING UNRECOVERED DEPRECIATION.[7] IS THIS TRUE?

A. Not entirely. It is true, as Mr. Mark Garrett notes, that in 2015, the OCC declined the request of Public Service Company of Oklahoma (PSO), a SWEPCO sister AEP operating company, to accelerate the depreciable lives of two generating units—Northeastern Unit 3 (retiring in 2026) and Unit 4 (retired in 2016)—such that all remaining costs of both plants would be recovered by 2026 when Unit 3 was retired. But that decision does not tell the whole story. What Mr. Mark Garrett leaves out is that despite embracing the "used and useful" ratemaking concept, the OCC allowed a carrying charge on the undepreciated value of PSO's retired Northeastern Unit 4 (NE 4):

> In balancing the interests of ratepayers and shareholders, THE COMMISSION FINDS it appropriate under the circumstances presented here to authorize a return of the investment associated with NE 4 and recovery of the carrying cost on the remaining investment at the cost of debt allowed in this proceeding."[8]

As noted above, the appropriate carrying charge on the remaining unrecovered balance of the Dolet Hills plant is SWEPCO's approved WACC.

[7] Direct Testimony of Mark E. Garrett at 33-34.

[8] *Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma,* Oklahoma Corporation Commission Cause No. PUD 201700151, Final Order (Order No. 672864) at 3 (Jan. 31, 2018).

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Q. STAFF WITNESS RAY AND INTERVENOR WITNESSES MARK GARRETT AND GLICK EACH POINT TO RECENT PRECEDENT FROM THE PUBLIC UTILITY COMMISSION OF TEXAS AS SUPPORT FOR THEIR POSITION THAT SWEPCO SHOULD BE DENIED A RETURN ON THE REMAINING UNRECOVERED BALANCE OF DOLET HILLS.[9] IS THIS TEXAS PRECEDENT BINDING HERE?

A. My understanding is that Texas precedent is not binding on this Commission. And, in my opinion, the Commission should not follow it as doing so would unfairly penalize SWEPCO for acting prudently and in the best interest of its customers. Moreover, the Texas precedent certainly does not reflect a *per se* standard uniformly followed by state regulators. This is evident from the regulatory treatment of AEP's coal plants retired in 2015, as discussed above. In addition, the Hawaii Public Utilities Commission has addressed circumstances similar to those faced by SWEPCO, recognizing that a carrying cost is an appropriate cost of service regarding the undepreciated value of retired property:

> We agree with GASCO that allowing a carrying charge on the unamortized balance of the value of retired or abandoned property is not equivalent to providing a rate of return on a rate base that is nonexistent as argued by the CA. Once it is determined that the undepreciated value of retired or abandoned property should be allowed to be amortized over a reasonable period, it is but a short step to allowing a carrying charge, on the unamortized balance, that relates to the cost of debt issued for the construction of retired or abandoned property, so long as the retirement or abandonment before the end of the property's useful life has been amply justified. The recovery allowed is recovery of all of the

[9] Direct Testimony of Middleton Ray at 11; Direct Testimony of Mark E. Garrett at 31-33; Direct Testimony of Devi Glick at 16-17.

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unrecovered cost of the property. We, thus, allow a carrying charge of 8.46 per cent per annum.[10]

Q. STAFF AND AG WITNESS MEYER IMPLY THAT SWEPCO SHOULD NOT EARN A RETURN ON THE REMAINING UNDEPRECIATED PORTION OF THE DOLET HILLS PLANT BECAUSE SWEPCO'S DECISION TO RETIRE THE PLANT WAS PART OF THE COMPANY'S NORMAL BUSINESS OPERATIONS.[11] DO YOU AGREE?

A. No. Customers and their regulators should encourage utilities to find new opportunities to reduce future costs as part of their normal operations, even if that involves abandoning a previously serviceable and prudently incurred investment. In contrast, denying full recovery gives utilities an incentive to operate plants until they have recouped all of their investment even though closing the plant would save customers money.

Q. SIERRA CLUB WITNESS GLICK INSISTS THAT ALLOWING SWEPCO TO RECOVER A RETURN ON ITS REMAINING UNRECOVERED INVESTMENT IN THE DOLET HILLS PLANT WILL SEND A DETRIMENTAL SIGNAL AND REMOVE ANY INCENTIVE TO RETIRE ITS EXISTING COAL PLANTS OR TO SEEK TO MINIMIZE ITS COSTS FOR THE BENEFIT OF ITS CUSTOMERS.[12] IS THIS TRUE?

A. No. In my opinion, the opposite is true. Allowing a utility to earn a return sends the signal that utilities should continuously look at opportunities to minimize costs because

[10] *Re Gasco, Inc.*, 132 P.U.R.4th 352 (Hawaii P.U.C. Apr. 3, 1992).

[11] Direct Testimony of Middleton Ray at 11; Direct Testimony of Greg R. Meyer at 16.

[12] Direct Testimony of Devi Glick at 15-16.

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there is no penalty. On the other hand, a disallowance sends the wrong signals to, and creates perverse incentives for resource planners and investors. Such a disallowance means that prior regulatory approvals cannot be relied upon. And, going forward, it creates the expectation that utilities will not be expected to recover a full return of and on their costs. In addition, a disallowance in this case sets a precedent of penalizing a utility for taking prudent steps to save customers money by retiring uneconomic assets. As a result, denying a return actually incentivizes a utility to stay the course with an uneconomic asset, even if another option would lead to net savings for customers in the long run.

Q. WHEN ASSESSING SWEPCO'S PROPOSAL, SHOULD THE COMMISSION CONSIDER THE REGULATORY CONSTRUCT UNDER WHICH SWEPCO OPERATES?

A. Absolutely. SWEPCO does not have unfettered options when it comes to determining when and where to enter a market or on what to charge for its services. Instead, SWEPCO has an obligation to serve customers in its territory and its rates are subject to review and approval by regulators. Thus, unlike a merchant generator, SWEPCO cannot profit by selling power at prevailing market prices, which at times exceed SWEPCO's regulated rates. Consequently, SWEPCO should not be assigned the downside losses when it prudently retires an asset because it happens to lose its economic advantages. This practice would deprive SWEPCO of a balanced opportunity to earn its allowed cost of capital. Moreover, such a built-in deprivation

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could harm SWEPCO's access to capital and undermine its ability to provide the requisite quality of service.

Q. DO YOU AGREE WITH THE AMORTIZATION SCHEDULES PROPOSED BY STAFF AND INTERVENOR WITNESSES MARK GARRETT AND MEYER?

A. No. As noted above, Staff and WALEC witness Mark Garrett propose a twenty-five year amortization period; AG witness Meyer proposes a ten-year amortization period. These periods are unreasonably long, particularly given that the prudence of SWEPCO's decision to retire Dolet Hills is unchallenged. As shown in Table 1 above, the longer the amortization period without a return on SWEPCO's remaining investment in the Dolet Hills plant, the greater the penalty to SWEPCO—i.e., the expected write off increases. However, the Commission should authorize SWEPCO to recover a return on its remaining, unrecovered investment in the Dolet Hills plant, regardless of the recovery period, as I state below.

Q. WHAT DO YOU RECOMMEND IF THE COMMISSION DOES NOT ALLOW A RETURN ON THE REMAINING, UNRECOVERED INVESTMENT?

A. If the Commission determines a return is not allowed, it should authorize SWEPCO to recover its remaining investment over the requested five-year period, which is consistent with the condition in the settlement agreement approved by the Commission in Docket 19-008-U, wherein the Company was obligated to seek permission to retire the plant by December 31, 2026. To extend the amortization period to ten or twenty-five years as requested by Staff and Intervenors would unfairly increase SWEPCO's

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penalty. It would also inappropriately encourage parties to advocate for an extended depreciation period of an asset's life to minimize a utility's return on its investment and then further advocate for extended recovery periods on the retired asset because there is no longer a return on the investment.

Q. GIVEN THE CONCERNS OVER POTENTIAL BILL IMPACTS, IS THERE A CIRCUMSTANCE UNDER WHICH SWEPCO COULD SUPPORT AN AMORTIZATION PERIOD LONGER THAN THE FIVE-YEAR PERIOD PROPOSED IN THIS CASE?

A. Yes. SWEPCO could support a longer amortization period, assuming a return at the WACC is authorized by the Commission.

Q. MR. MARK GARRETT PROVIDES A NUMBER OF EXAMPLES OF THINGS HE CLAIMS CAN OFFSET OR HELP PAY FOR THE COSTS RESULTING FROM THE EARLY RETIREMENT OF A PLANT. HE ARGUES THAT VARIOUS THINGS LIKE NEW TECHNOLOGIES AND INCREASED OPERATING EFFICIENCIES CAN HELP PAY FOR THE UNAVOIDABLE COSTS OF RETIRING A PLANT EARLY IF THE COSTS ARE SPREAD OVER A REASONABLE AMOUNT OF TIME.[13] DO YOU AGREE?

A. No, I do not agree. I do not dispute that it is possible, as Mr. Mark Garrett speculates, that new technologies, lower capital costs, or load growth can offset the financial impact associated with the retirement of a plant with undepreciated costs. But that possibility is entirely speculative and ignores the aging infrastructure within the

[13] Direct Testimony of Mark E. Garrett at 38-40.

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industry. Mr. Mark Garrett also fails to account for the fact that any cost savings from new technologies or lower capital costs would generally flow back to the benefit of customers during the Commission's review of SWEPCO's cost-of-service under the FRR Rider, if approved.

Importantly, should Mr. Mark Garrett's theoretical possibilities not come to pass, the financial harm to SWEPCO of denying a return on its remaining, unrecovered investment in the Dolet Hills plant is a certainty, as shown in Table 1 above. Given SWEPCO's prudent actions in retiring the plant for the benefit of customers, it should not be put in the position of relying on the mere potential of future cost savings of hypothetical outcomes to be able to offset the penalty and also be able to earn a return on this asset.

B. PIRKEY

Q. WALEC WITNESS MARK GARRETT RECOMMENDS THAT THE COMMISSION REJECT SWEPCO'S REQUEST TO ACCELERATE RECOVERY FOR PIRKEY AND ORDER SWEPCO TO ADHERE TO THE EXISTING DEPRECIABLE LIFE OF THE PIRKEY PLANT.[14] PLEASE RESPOND.

A. Mr. Mark Garrett's recommendation is unreasonable. The Pirkey plant will retire in early 2023. Generally Accepted Accounting Principles (GAAP) would require the remaining book value of the plant be fully depreciated over its remaining useful life or through the retirement date in 2023. To mitigate bill impacts that would result from

[14] Direct Testimony of Mark E. Garrett at 41-42.

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the accelerated recovery required under GAAP, SWEPCO is requesting to set depreciation rates using a 2037 retirement date and to roll any remaining net book balance of the Pirkey plant into the accumulated depreciation balance of the Welsh plant upon Pirkey's retirement in 2023. I believe SWEPCO's request reasonably balances the interests of SWEPCO and its customers.

Q. SIERRA CLUB WITNESS GLICK ARGUES THAT THE COMMISSION SHOULD NOT ALLOW SWEPCO TO EARN A RETURN ON THE PIRKEY PLANT BALANCE AFTER THE PLANT'S RETIREMENT.[15] HOW DO YOU RESPOND?

A. As discussed above in response to similar recommendations regarding the Dolet Hills plant, denying SWEPCO a return on its remaining, unrecovered investment in a prudently retired plant is bad policy and would encourage utilities to continue to operate plants even when retirement could result in cost savings to customers.

C. WELSH

Q. PLEASE SUMMARIZE SWEPCO'S RECOMMENDATION CONCERNING THE DEPRECIATION TREATMENT AND RECOVERY OF ANY REMAINING UNRECOVERED BOOK VALUE RELATED TO THE WELSH PLANT'S COAL OPERATIONS.

A. As noted in my direct testimony, Welsh will cease coal operations in early 2028 pursuant to the requirements outlined in the EPA's CCR and ELG Rules. However, to

[15] Direct Testimony of Devi Glick at 6-7.

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mitigate the customer impact of that decision, SWEPCO is proposing to recover the remaining book value of Welsh through 2037, rather than 2028.

Q. MR. MARK GARRETT RECOMMENDS THAT THE COMMISSION ORDER SWEPCO TO ADHERE TO THE EXISTING DEPRECIABLE LIVES OF THE WELSH UNITS.[16] PLEASE RESPOND.

A. Mr. Mark Garrett's recommendation is unnecessary as to Welsh Unit 1 and unreasonable as to Welsh Unit 3. Despite Mr. Mark Garrett's claim, under SWEPCO's depreciation proposal, Welsh Unit 1 would continue to be depreciated using a 2037 retirement date as approved in Docket No. 19-008-U. SWEPCO has proposed shifting the depreciable life of Welsh Unit 3 from 2042 to 2037. This shift reasonably synchronizes the amortization periods of the Welsh units to be in line with the operational lives of the units should SWEPCO determine that a natural gas conversion of the units is in the best interests of customers. As discussed further below, the economic modeling underlying the Preferred Plan in SWEPCO's recently filed Integrated Resource Plan (IRP),[17] supports the conversion of Welsh Unit 1 to run on natural gas in 2028 and operate for an additional 10 years through the end of 2037. As part of the five-year action plan outlined in the IRP (2022-2026), SWEPCO will seek to refine the cost estimates and develop plans for the potential Welsh Unit 1 gas conversion. SWEPCO will also have the opportunity to test and evaluate the options for Welsh Unit 3.

[16] Direct Testimony of Mark E. Garrett at 42.

[17] *See* APSC Docket 07-011-U Document 44 filed December 15, 2021.

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IV. FORMULA RATE REVIEW RIDER PROPOSAL

Q. IN SWEPCO'S LAST BASE-RATE CASE, THE COMMISSION APPROVED A SETTLEMENT IN WHICH THE PARTIES AGREED TO A FRR RIDER FOR SWEPCO. ON APRIL 2, 2021, HOWEVER, SWEPCO GAVE NOTICE OF ITS WITHDRAWAL FROM THE APPROVED FRR. WHAT WAS THE BASIS FOR SWEPCO'S WITHDRAWAL?

A. SWEPCO elected to proceed with this rate case instead of filing its annual FRR evaluation report in order to bring the North Central Energy Facilities (NCEF) into its base rates in a timely manner.

Q. WALEC WITNESS MARK GARRETT ARGUES THAT SWEPCO VIOLATED THE UNANIMOUS SETTLEMENT AGREEMENT IN DOCKET NO. 19-008-U BY WITHDRAWING FROM THE FRR RIDER AGREED TO IN THAT CASE. PLEASE RESPOND.

A. Mr. Garrett is unreasonably attempting to transform the FRR Rider agreed to in Docket No. 19-008-U into a five-year rate-case stay out provision for SWEPCO. But neither the Unanimous Settlement Agreement in Docket No. 19-008-U nor the FRR Rider agreed to in that case contain such a provision. And SWEPCO would not have agreed to such a stay-out provision. It is true that the FRR Rider agreed to in the Docket No. 19-008-U settlement had a five-year term. But nowhere in the Unanimous Settlement Agreement or the FRR Rider does it state that SWEPCO cannot unilaterally withdraw from the FRR Rider adopted by the Commission in that case. Moreover, the FRR Rider adopted in Docket No. 19-008-U clearly states that the Formula Rate Review Act

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(FRRA), Ark. Code Ann. §§ 23-4-1201 *et seq.*, controls in the event of a conflict between it and the FRR Rider. And, although I am not a lawyer, my understanding is that a utility's election to be regulated under the FRRA is entirely voluntary and it is solely within the utility's discretion to return to traditional ratemaking. Indeed, FRRA § 23-4-1209(a) states:

> This subchapter does not repeal any other provision in this chapter and is supplemental to other laws governing the regulation of public utility rates.

Thus, it appears to me, that a utility operating under a formula rate plan is authorized to seek regulation under traditional ratemaking procedures at any time so long as the utility does not pancake rate cases.[18]

Q. THE JOINT UNANIMOUS SETTLEMENT AGREEMENT IN DOCKET NO. 19-035-U PROVIDES THAT "ANY FORMULA RATE RIDER PROPOSED BY THE COMPANY IN ITS NEXT GENERAL RATE CASE FILING WILL CONTAIN THE SAME TERMS AND CONDITIONS AS THE FORMULA RATE RIDER APPROVED BY THE COMMISSION PURSUANT TO THE SETTLEMENT FILED IN DOCKET NO. 19-008-U." STAFF SUGGESTS THAT SWEPCO HAS VIOLATED THIS SETTLEMENT PROVISION BY PROPOSING TO INCLUDE THE TAX DEFERRAL MECHANISM AS PART OF THE FRR RIDER IN THIS CASE.[19] PLEASE RESPOND.

[18] *See* Ark. Code Ann. § 23-4-19.
[19] Direct Testimony of Regina L. Butler at 8-10.

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A. SWEPCO's requested inclusion of the tax deferral mechanism in the proposed FRR Rider was intended to afford SWEPCO the ability to efficiently address changes in the federal corporate income tax rate, which would operate for the benefit of both the Company and customers depending on the direction of the tax rate change. But given Staff's concerns, SWEPCO has withdrawn this request. With that change, SWEPCO's proposed FRR Rider in this case is the same as the FRR Rider agreed upon by all parties and approved by the Commission in Docket No. 19-008-U.

Q. DOES THE PROPOSED FRR RIDER MEET THE REQUIREMENTS OF ACT 725?

A. Yes. SWEPCO's proposed FRR Rider meets the goals and requirements of the FRRA and the rider's adoption would benefit SWEPCO and its customers alike. The proposed FRR Rider provides a streamlined process to adjust rates annually reflecting the costs incurred to provide service to SWEPCO's Arkansas retail customers and provides SWEPCO the opportunity to earn its authorized return on common equity. The proposed FRR Rider would also benefit SWEPCO's customers by ensuring SWEPCO's rates are closely aligned with its costs on an annual basis, which promotes greater rate stability and reduces the potential for large rate swings generally associated with base-rate cases.

Q. WERE PROPOSALS MADE BY ANY INTERVENORS TO MODIFY SWEPCO'S FRR RIDER PROPOSAL?

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A. Yes. AG witness Gorman has proposed five modifications to SWEPCO's requested FRR Rider.[20] SWEPCO witness John Aaron addresses each of Mr. Gorman's recommended modifications in his Rebuttal Testimony.

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS REGARDING MR. GORMAN'S FIVE PROPOSALS TO MODIFY THE FRR RIDER?

A. Yes. Generally, I believe that Mr. Gorman's proposed modifications to the FRR Rider are unnecessary. As discussed above, aside from the requested tax deferral mechanism (which Mr. Gorman does not address and SWEPCO has agreed to withdraw), SWEPCO's proposed FRR Rider is identical to the FRR Rider that all parties to Docket No. 19-008-U, including the AG, agreed was reasonable. In addition, four of Mr. Gorman's five proposals are similar to or the same as his proposed modifications to SWEPCO's FRR Rider proposed in Docket No. 19-008-U, which were abandoned in the settlement in that docket.

V. SUFFICIENCY OF SWEPCO'S EVIDENTIARY SUPPORT FOR ITS CAPITAL INVESTMENT AND AFFILIATE AND TRANSMISSION O&M EXPENSE

Q. MR. NORWOOD CLAIMS THAT SWEPCO'S APPLICATION AND DIRECT TESTIMONY DOES NOT SUPPORT THE REASONABLENESS OR PRUDENCE OF ANY SPECIFIC CAPITAL ADDITION PROJECT OR SWEPCO'S REQUESTED AFFILIATE O&M EXPENSES.[21] IS THIS TRUE?

[20] Direct Testimony of Michael P. Gorman at 12-22.

[21] Direct Testimony of Scott Norwood at 11, 16-17, and 19-20.

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A. Absolutely not. As required in every rate case, SWEPCO filed direct testimony, exhibits, and workpapers describing and supporting its requested rate relief. In addition, SWEPCO complied with the Commission's Rules of Practice and Procedure (RPPs) by preparing and filing all required schedules and information identified in the RPP's Minimum Filing Requirements (MFRs), along with supporting workpapers.

Further, the Commission Staff, which is charged with analyzing rate increase applications for deficiencies, did not identify any aspect of SWEPCO's application as deficient.

I find it surprising that Mr. Norwood would claim that SWEPCO's application and direct testimony are somehow deficient and inadequate to support SWEPCO's rate request given that: (1) SWEPCO's rate filing package in this case is consistent with that filed in past cases in 2019 and 2009; and (2) Mr. Norwood testified on behalf of the AG in SWEPCO's last rate case (2019) and made no such claim in that case. Likewise, the AG did not raise such a claim in SWEPCO's 2009 rate case.

Q. MR. NORWOOD CLAIMS THAT SWEPCO ASSERTS THAT IT IS NOT REQUIRED TO DEMONSTRATE THE REASONABLENESS OR PRUDENCE OF ITS RATE YEAR CAPITAL ADDITIONS OR ITS REQUESTED TEST YEAR AFFILIATE O&M.[22] IS THIS CORRECT?

A. No, Mr. Norwood's claim is false and misleading. Indeed, the discovery responses Mr. Norwood cites as proof of his claim say no such thing. Specifically, Mr. Norwood cites to SWEPCO's responses to AG data requests 1-8 and 1-25, which asked SWEPCO to

[22] Direct Testimony of Scott Norwood at 6-7, and 17.

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identify the specific passages of direct testimony of each SWEPCO witness supporting the "reasonableness of affiliate charges requested by each affiliate in this case," and "prudence of each Production Plant capital addition whose cost was more than $5 million for which the Company is requesting approval to include in rate base in this case."[23] In response to both requests, SWEPCO notes the general fact that in the Arkansas jurisdiction, capital additions and affiliate expenses are reviewed as part of the overall level of reasonable expenditures and are not specifically supported as separate items. At no point in either response did SWEPCO assert that it is not required to demonstrate the reasonableness or prudence of its pro forma test year capital additions or its requested test year affiliate O&M expense.

Mr. Norwood also cites to SWEPCO's responses to AG data requests 8-16, 8-18, 8-20, 8-22, and 8-24 as evidence of SWEPCO's alleged position that it has no obligation to provide evidence to support the prudence of major investments in its Arkansas rate increase applications.[24] These data requests, however, merely asked SWEPCO to confirm or deny that its direct testimony does not specifically address the reasonableness or prudence of specific Production Plant, Transmission Plant, Distribution Plant, General Plant, and Intangible Plant capital additions whose cost was more than $5 million.[25] And SWEPCO neither confirmed nor denied the assertion. Rather, SWEPCO referred the AG to SWEPCO's response to AG 8-4, which states:

[23] *See* SWEPCO Response to AG 1-8 and 1-25, included in Exhibits SN-2 and SN-6 to Mr. Norwood's Direct Testimony.
[24] Direct Testimony of Scott Norwood at 11-12 and Exhibit SN-5.
[25] SWEPCO's responses to these data requests are included in Exhibit SN-5 to Mr. Norwood's Direct Testimony.

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> As in any rate proceeding before this Commission, the Company's filed direct testimony, exhibits, MFRs, workpapers, data responses, to-be-filed rebuttal and sur-rebuttal testimonies have and will fully support its request.[26]

To be clear, SWEPCO fully accepts that it has the ultimate burden in this proceeding of proving that its requested rate change is just and reasonable, which necessarily includes establishing the prudence, reasonableness, and necessity of its capital investment and O&M expenses.

Q. HAS SWEPCO RESPONDED TO NUMEROUS AG DATA REQUESTS REGARDING CAPITAL PROJECTS AND AFFILIATE O&M EXPENSES IN THIS BASE RATE CASE?

A. Yes. In fact, in addition to those specifically mentioned by SWEPCO witness Yoder, SWEPCO has responded to the AG's data requests seeking the following information:

- the total charges to SWEPCO from each affiliate during the 2018, 2019, 2020, and as requested in rates in this case (AG 1-7);
- annual capital expenditures at each SWEPCO power plant for each of the last three calendar years, the test year, and as requested in rates for the first time in this case (AG 1-23);
- project descriptions, project cost, in-service date, and cost/benefit summaries for each production plant capital addition project whose cost was more than $5 million, and which was placed in service since the Company's last Arkansas base rate case (AG 1-24);
- transmission O&M expenses by FERC account for each of the last three calendar years, the test year, and as requested in rates in this case (AG 1-26);
- transmission capital additions for each of the last three calendar years, the test year, and as requested in rates for the first time in this case (AG 1-27);

[26] *See* SWEPCO Response to AG 8-4, included in Exhibit SN-5 to Mr. Norwood's testimony.

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- project descriptions, project cost, in-service date, and cost/benefit summaries for each Transmission Plant capital addition project whose cost was more than $5 million, and which was placed in service since the Company's last Arkansas base rate case (AG 1-28);

- distribution O&M expenses by FERC account for each of the last three calendar years, the test year, and as requested in rates in this case (AG 1-30);

- Distribution Plant capital additions for each of the last three calendar years, the test year, and the total requested in rates for the first time in this case (AG 1-31);

- project descriptions, project cost, in-service date, and cost/benefit summaries for each Distribution Plant capital addition project whose cost was more than $5 million, and which was placed in service since the Company's last Arkansas base rate case (AG 1-32);

- project descriptions, project cost, in-service date, and cost/benefit summaries for each General Plant capital addition project whose cost was more than $5 million, and which was placed in service since the Company's last Arkansas base rate case (AG 2-8);

- project descriptions, project cost, in-service date, and cost/benefit summaries for each Intangible Plant capital addition project whose cost was more than $5 million, and which was placed in service since the Company's last Arkansas base rate case (AG 2-11);

- a description and identification of all processes, with documentation, used by SWEPCO, and relied upon by SWEPCO's witnesses in this case, to determine the reasonableness and prudency of the information contained within the Company's MFRs schedules as they pertain to all of the capital projects submitted for inclusion in customer rates in this case (AG 8-2(a));

- identification of all workpapers which were provided by the Company to any party either simultaneously at the time of filing its Application and supporting testimony, or in subsequent discovery (AG 8-2(b));

- identification of the SWEPCO witness that supports the proposed pro forma adjustments to production plant capital additions, along with the specific workpapers and testimony that describe and support the need for and reasonableness of specific projects included in these pro forma adjustments (AG 9-17);

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- identification of the SWEPCO witness that supports the proposed pro forma adjustments to Arkansas distribution plant capital additions, along with the specific workpapers and testimony that describe and support the need for and reasonableness of specific projects included in these pro forma adjustments (AG 9-18);

- identification of the SWEPCO witness that supports the proposed pro forma adjustments to transmission plant capital additions, along with the specific workpapers and testimony that describe and support the need for and reasonableness of specific projects included in these pro forma adjustments (AG 9-19);

- identification of the SWEPCO witness that supports the proposed pro forma adjustments to general plant capital additions, along with the specific workpapers and testimony that describe and support the need for and reasonableness of specific projects included in these pro forma adjustments (AG 9-20); and

- identification of the SWEPCO witness that supports the proposed pro forma adjustments to intangible plant capital additions, along with the specific workpapers and testimony that describe and support the need for and reasonableness of specific projects included in these pro forma adjustments (AG 9-21).

Given SWEPCO's responses to these data requests, it is obvious that the AG has received significant amounts of evidence supporting the need for or prudence of SWEPCO's capital additions and the reasonableness of its affiliate O&M expenses.

Q. WAS THE AG PROVIDED WITH COPIES OF SWEPCO'S RESPONSES TO ALL DATA REQUESTS PROPOUNDED BY ANY INTERVENOR OR STAFF, INCLUDING THE REQUESTS IDENTIFIED ABOVE?

A. Yes, SWEPCO provided the AG with copies of the responses to every data request answered by SWEPCO in this case.

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Q. HOW MANY DATA REQUESTS HAS SWEPCO ANSWERED IN THIS CASE?

A. Throughout the discovery period to date, SWEPCO has responded to over 700 data requests, not counting subparts.

Q. OF THE 700 DATA REQUESTS ANSWERED BY SWEPCO, HOW MANY ARE RELATED TO CAPITAL PROJECTS AND AFFILIATE ISSUES RAISED BY THE AG?

A. Approximately 80 of the data requests are related to the affiliate O&M and capital project issues raised by the AG.

Q. IS SWEPCO FILING ADDITIONAL INFORMATION CONCERNING ITS CAPITAL ADDITIONS AND AFFILIATE O&M EXPENSES AS PART OF ITS REBUTTAL CASE?

A. Yes, SWEPCO is filing the Rebuttal Testimony of the following witnesses in response to Mr. Norwood's allegations:

- Therace M. Risch – addresses the reasonableness and necessity of SWEPCO's information technology capital investment;
- Sara N. Vestfals – addresses the necessity and reasonableness of SWEPCO's generation capital additions in this case;
- Drew W. Seidel – addresses the reasonableness and necessity of SWEPCO's distribution plant capital investment;
- Jeffrey L. Ellis – addresses the reasonableness and necessity of SWEPCO's transmission plant capital investment; and
- Brian J. Frantz and Jason Yoder – address the reasonableness and necessity of SWEPCO's affiliate expenses.

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VI. EVALUATION OF CONTINUED OPERATION OF CERTAIN COAL AND LIGNITE UNITS

Q. STAFF WITNESS ATHAS NOTES THAT SWEPCO'S UNIT DISPOSITION ANALYSIS OF THE PIRKEY POWER PLANT INDICATES THAT THE EARLIER THE PLANT IS RETIRED THE GREATER THE ECONOMIC BENEFITS.[27] THE SUGGESTION IS THAT SWEPCO SHOULD RETIRE PIRKEY EARLIER THAN 2023. PLEASE RESPOND.

A. It is unclear to me whether Mr. Athas is arguing that SWEPCO should evaluate retiring Pirkey earlier than 2023. But, in any event, it is not practical to consider an earlier retirement for the plant. The Pirkey plant is set to retire in early 2023—i.e., before the peak summer months. Thus, if SWEPCO were to consider an earlier retirement of the plant, it would need to occur before the 2022 summer peak to make economic sense. In my experience, however, there is not sufficient time to develop a Request for Proposals (RFP) and go to market to seek replacement capacity for Pirkey before summer 2022.

Q. BASED ON HIS COMPARISON OF THE RESULTS OF SWEPCO'S ORIGINALLY FILED UNIT DISPOSITION ANALYSIS FOR PIRKEY WITH THE RESULTS IN THE COMPANY'S SUBSEQUENT ERRATA FILING, MR. ATHAS ARGUES THAT SWEPCO SHOULD CONDUCT AN ADDITIONAL ANALYSIS TO DETERMINE IF RETIRING WELSH PRIOR TO 2028 MIGHT

[27] Direct Testimony of John G. Athas at 23.

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BE IN THE BEST INTEREST OF CUSTOMERS.[28] DO YOU AGREE THAT SUCH ADDITIONAL ANALYSIS IS NECESSARY?

A. No, I do not agree. First, it is important to note that while SWEPCO has determined that it will cease coal operations at Welsh by 2028, a decision to completely retire the plant has not been made. Indeed, as noted above, the economic modeling supporting the Preferred Plan identified in SWEPCO's recently filed IRP, calls for Welsh Unit 1 to be converted to run on natural gas in 2028 and operate for an additional 10 years through the end of 2037. Because the IRP was filed with the APSC in December 2021, Mr. Athas did not have the benefit of that information when he developed his testimony in this proceeding.

Second, as explained in more detail in the Rebuttal Testimony of SWEPCO witness Joseph Perez, it is not valid to extrapolate SWEPCO's unit disposition analysis of Pirkey to Welsh.

Finally, retirement of Welsh prior to 2028 is impractical from a timing perspective. Retirement of the plant would create an immediate need to fill approximately 1,000 MW of capacity to satisfy SWEPCO's reserve margin. Based on my experience with preparing RFPs for capacity resources for SWEPCO, securing approximately 1,000 MW of capacity to meaningfully accelerate the retirement of the Welsh plant prior to 2028 would be extremely difficult, if not impossible.

[28] Direct Testimony of John G. Athas at 23.

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Q. SIERRA CLUB WITNESS GLICK ASSERTS THAT PRIOR TO MAKING ANY INVESTMENTS IN A CONVERSION OF THE WELSH UNITS TO NATURAL GAS, SWEPCO SHOULD BE REQUIRED TO PRODUCE A ROBUST ANALYSIS THAT EVALUATES AND COMPARES THE COSTS OF CONVERTING THE PLANT TO THE COST OF RETIRING THE PLANT AND INVESTING IN ALTERNATIVES.[29] PLEASE ADDRESS MS. GLICK'S RECOMMENDATION.

A. Of course SWEPCO will evaluate and compare the cost of converting the Welsh units to natural gas with retiring the plant and investing in alternatives before moving forward with any action plan. Indeed, this type of analysis is integral to SWEPCO's required IRP, which was most recently updated and filed in December 2021. As I noted above, as part of its 2021 IRP, SWEPCO has evaluated and will continue to refine the cost estimates incorporated into its evaluation and develop plans for the potential conversion of Welsh Unit 1.

Q. SIERRA CLUB WITNESS GLICK CONTENDS THAT SWEPCO HAS NOT COMPLIED WITH THE COMMISSION'S REQUIREMENT AS PART OF ITS APPROVAL OF THE SCRUBBERS AT FLINT CREEK IN DOCKET 12-008-U TO ADDRESS THE LOAD POCKET IN NORTHWEST ARKANSAS.[30] IS THIS TRUE?

[29] Direct Testimony of Devi Glick at 58.

[30] Direct Testimony of Devi Glick at 5.

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A. No, it is not true. It important to be clear what exactly the Commission order in Docket No. 12-008-U required from SWEPCO in regard to the load pocket in Northwest Arkansas. Ms. Glick implies that SWEPCO was required to take some sort of definitive action to address and resolve the load pocket. But this is an overstatement of the Commission's decision in Docket No. 12-008-U. The Commission's support for the retrofit of Flint Creek in Docket No. 12-008-U was based, in part, upon a number of factors, including that SWEPCO "will continue to work with Southwest Power Pool (SPP) to conduct an appropriate solutions study to timely address reliability issues in the Northwest Arkansas load pocket." Aside from this finding, there is no directive regarding how or by when SWEPCO is to address the load pocket.

Consistent with the Commission's decision in Docket No. 12-008-U, SWEPCO has continued working with SPP to address the load pocket in Northwest Arkansas. As explained in more detail in SWEPCO witness Jeffrey Ellis's Rebuttal Testimony, SWEPCO's efforts with the SPP have resulted in transmission upgrades. Mr. Ellis identifies these upgrades, describes the annual reliability studies required by SPP, and discusses transmission alternatives considered as part of this process.

Q. CITY OF FAYETTEVILLE WITNESS NIERENGARTEN RECOMMENDS THAT THE COMMISSION SHOULD DIRECT SWEPCO TO CONDUCT A TRANSPARENT STUDY TO ADDRESS THE NORTHWEST ARKANSAS LOAD POCKET AND TRANSMISSION RELIABILITY ISSUES.[31] MR. NIERENGARTEN ALSO MAINTAINS THAT THIS STUDY SHOULD

[31] Direct Testimony of Peter Nierengarten at 9.

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ENGAGE COMMUNITY STAKEHOLDERS AND SEEK TO ADDRESS COMMUNITY RELIABILITY, CLEAN ENERGY AND OTHER GOALS. PLEASE RESPOND.

A. As noted above and discussed in the Rebuttal Testimony of SWEPCO witness Ellis, SWEPCO has studied and will continue to study reliability issues surrounding the load pocket in Northwest Arkansas as part of its overall planning process and in its IRP evaluations. I believe that SWEPCO's historic method of engagement in the IRP's stakeholder process provides the community engagement opportunities Mr. Nierengarten seeks.

Q. STAFF WITNESS ATHAS ASSERTS THAT SWEPCO'S UNIT DISPOSITION ANALYSIS OF FLINT CREEK IS NOT SUFFICIENTLY ROBUST TO SUPPORT THE RETROFIT VERSUS RETIREMENT ASSESSMENT BECAUSE IT DOES NOT INCLUDE AN ANALYSIS OF AN ALTERNATIVE SCENARIO IN WHICH NEW CAPACITY IS ADDED IN NORTHWEST ARKANSAS.[32] PLEASE RESPOND.

A. The purpose of the unit disposition analysis was to evaluate SWEPCO's options to comply with the EPA's CCR and ELG rules. In my opinion, the evaluation included all economically viable options for complying with these rules for Flint Creek. As explained in SWEPCO witness Perez's Direct Testimony, an array of conventional and renewable generating technologies were evaluated in the Fall 2020 unit disposition analysis of Flint Creek. Specifically, natural gas fired combined cycles and combustion

[32] Direct Testimony of John G. Athas at 29.

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turbines; carbon-free resources such as wind, solar and storage; and market capacity were all considered as replacement capacity options in the resource plans. Due to transmission system constraints in northwest Arkansas, if the Flint Creek plant were to be retired, extensive transmission construction would be required to maintain system reliability. These constraints were necessarily incorporated into the analysis. The cost of the transmission upgrade was estimated to cost $150 million at the time of the 2020 unit disposition analysis.[33]

Mr. Athas appears to be arguing that SWEPCO should have considered whether a generation resource could replace the capacity provided by Flint Creek and avoid the need for the $150 million in transmission upgrades. But, as noted above, the Flint Creek unit disposition analysis does consider new generation resources as an alternative to retrofitting the plant. Moreover, by evaluating the retrofit option to comply with the CCR and ELG rules, SWEPCO also considered a generation option—i.e., Flint Creek—that would provide capacity without the necessity for a transmission upgrade to address reliability concerns in the Northwest Arkansas load pocket for the duration of the extended life of the Flint Creek plant. The retrofit option is the only generation solution that could provide capacity and alleviate the need for the transmission upgrade that made economic sense.

[33] As explained in SWEPCO witness Ellis's Rebuttal Testimony, the estimated cost of the necessary transmission upgrades has increased to $205 million.

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VII. ENERGY COST RECOVERY RIDER

Q. IN ITS 2021 RIDER ECR FILING, SWEPCO INCLUDED THE AMORTIZATION OF THE DOLET HILLS LIGNITE COMPANY MINING COSTS OVER FIVE YEARS. STAFF WITNESS KIM O. DAVIS OPPOSES SWEPCO'S PROPOSED AMORTIZATION PERIOD AND INSTEAD RECOMMENDS AMORTIZING THE DOLET HILLS MINING COMPANY COSTS OVER TWENTY-FIVE YEARS.[34] PLEASE RESPOND.

A. SWEPCO's proposed five-year amortization of the Dolet Hills Lignite Company's (DHLC) remaining mining costs is consistent with the expected life of the mine after the acquisition of the Oxbow Reserves in 2009, which was necessary to ensure there was sufficient lignite to fuel the power plant through 2026. But for the acquisition of the Oxbow reserves, mining and in turn operation of the Dolet Hills plant would have become uneconomic at some point between 2016 and 2019. The APSC approved the acquisition of the Oxbow Reserves in Docket No. 09-055-U. The LPSC also approved the acquisition and one of the conditions in the Order was that the Company commit to running the plant and mine through 2026, unless a change in economic, environmental, or operational circumstances required an earlier retirement. I have included the LPSC Order approving the acquisition as REBUTTAL EXHIBIT TPB-1.

SWEPCO's proposed amortization is also consistent with the Unanimous Modified Settlement in Docket No. 19-008-U, which was approved by the

[34] Direct Testimony of Kim O. Davis at 10.

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Commission. In that agreement, SWEPCO committed to seek permission to retire the Dolet Hills plant by 2026.

Finally, in its March 30, 2021 submittal letter with its 2021 Rider ECR update in Docket No. 19-008-U, SWEPCO made clear that the filing included the amortization of the DHLC mining costs over five years. The submittal letter also noted that in the absence of an objection, SWEPCO would implement the proposed 2021 Rider ECR during the first billing cycle of April 2021. There was no objection and the 2021 Rider ECR with a five-year amortization of the DHLC mining costs was implemented. This is likely due, in part, to the facts that: (1) before filing the 2021 Rider ECR, SWEPCO negotiated the amortization of the DHLC mining costs with Commission Staff; and (2) absent the five-year amortization period, all of the DHLC mining costs would have been recovered through the Rider ECR in 2021.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing Direct Testimony was electronically served upon all parties of record via the Commission's EFS system on this 13th day of January 2022.

/s/ Stephen K. Cuffman
Stephen K. Cuffman

LOUISIANA PUBLIC SERVICE COMMISSION

ORDER NO. U-30975

Cleco Power. L.L.C. and Southwestern Electric Power Co.

DOCKET NO. U-30975 - In Re: JOINT APPLICATION OF CLECO POWER LLC AND SOUTHWESTERN ELECTRIC POWER COMPANY FOR: (I) AUTHORIZATION TO ENTER INTO A PROPOSED AGREEMENT WITH NORTH AMERICAN COAL TO PURCHASE THE PERMIT, LEASES, AND RESERVES ASSOCIATED WITH THE OXBOW MINE; (II) AUTHORIZATION TO INCLUDE THE PERMIT, LEASES, AND RESERVES IN JURISDICTIONAL RATE BASE AND RELATED RATE MAKING TREATMENTS; AND (III) EXPEDITED TREATMENT

(Decided at the September 16, 2009 Business & Executive Session)

I. <u>INTRODUCTION</u>

This matter is before the Louisiana Public Service Commission ("Commission") to consider a Proposed Uncontested Stipulated Settlement entered into in this proceeding by the Louisiana Public Service Commission Staff ("Staff"), Cleco Power LLC ("Cleco Power") and Southwestern Electric Power Company ("SWEPCO") (Cleco Power and SWEPCO collectively, "the Companies"), for the purpose of settling all of the issues in this proceeding that relate to the <u>Joint Application of Cleco Power LLC and Southwestern Electric Power Company for: (i) Authorization to Enter into a Proposed Agreement with North American Coal to Purchase the Permit, Leases, and Reserves Associated with the Oxbow Mine; (ii) Authorization to Include the Permit, Leases, and Reserves in Jurisdictional Rate Base and Related Rate Making Treatments; and (iii) Expedited Treatment</u> ("Joint Application"), as filed by Cleco Power and SWEPCO with the Commission April 30, 2009 in Docket No. U-30975. The Proposed Uncontested Stipulated Settlement, if approved, would resolve all of the issues raised in the Joint Application. As is more fully set forth below, considering the record in this Docket, and the all-in cost of power from the Dolet Hills unit, even after the small increase in fuel costs resulting from the settlement, the Commission determines that the Proposed Uncontested Stipulated Settlement is fair to both customers and the Companies, will produce just, reasonable and not unduly discriminatory rates, and is in the public interest.

II. JURISDICTION

The Commission exercises jurisdiction in this proceeding pursuant to Article IV, Sec. 21 of the Louisiana Constitution, La. R.S. 45:1163 (A)(1), and La. R.S. 45:1176.

La. Const. Art IV Sec. 21 provides in pertinent part:

> The Commission shall regulate all common carriers and public utilities and have such other regulating authority as provided by law. It shall adopt and enforce reasonable rules, regulations and procedures necessary for the discharge of its duties, and perform other duties as provided by law.

Statutory authority for the Commission's regulation of public utilities, including electric utilities is found in La. R.S. 45:1163 and La. R.S. 45:1176.La. R.S. 45:1163 provides in pertinent part:

> A. (1) The Commission shall exercise all necessary power and authority over any street railway, gas, electric light, heat, power, waterworks or other local public utility for the purpose of fixing and regulating the rates charged or to be charged by and services furnished by such public utilities.

III. BACKGROUND AND DISCUSSION

The Dolet Hills Power Plant is a 650 MW baseload unit fired by lignite and located in DeSoto Parish, Louisiana. It is a "mine mouth" operation with the source of the lignite located immediately adjacent to the power plant. The plant is owned 50% by Cleco Power, 40% by SWEPCO, and 10% by two minority owners. Cleco Power operates the plant.

This docket was preceded by two prior dockets that dealt with the Dolet Hills Power Station ("DHPS") and the Dolet Hills Lignite Company ("DHLC"). Both of those prior dockets, which are summarized below, were settled by the Companies and Staff and the settlements were approved by the Commission.

In Order No. U-21453, U-20925(SC) and U-22092(SC), Subdocket G, dated May 31, 2001 ("Dolet Hills Order"), the Commission approved an April 2001 Term Sheet for the Dolet Hills Mining Proposal. The 2001 Term Sheet was the result of negotiations among Cleco, SWEPCO, and the LPSC Staff. The Term Sheet provided for the replacement of the then existing Dolet Hills miner with a new mining company, Dolet Hills Lignite Mining Company LLC ("SWEPCO Miner"), an affiliate of SWEPCO. The term sheet also provided for a guaranteed minimum lignite cost savings to Louisiana ratepayers of at least 2% of the "would have been" price of the former mining company, Dolet Hills Mining Venture ("DHMV"). All

lignite costs in excess of 98% of the "would have been" DHMV costs were to be deferred and collected in subsequent years in which the SWEPCO Miner's costs fell below the 98% threshold. The 2001 Term Sheet provided that the "would have been" DHMV costs were to be escalated at the Gross Domestic Product Implicit Price Deflator ("GDP-IPD") Index going forward. Thus, if the SWEPCO Miner's lignite costs exceeded 98% of the escalated "would have been costs", such costs would be deferred for future collection.

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The Dolet Hills Order noted that the pricing provisions of the Term Sheet ensured that the costs from the SWEPCO Miner were at the lower of cost or market and that the Companies had demonstrated economic benefits from the Term Sheet as a prerequisite for the collection of the SWEPCO Miner's costs through their Fuel Adjustment Clauses ("FACs"). The change-over in the operation of the mine in 2001 has saved Cleco's and SWEPCO's Louisiana ratepayers millions of dollars.

The next relevant proceeding was Docket No. U-29797, in which the Commission issued a December 4, 2007 Order that approved an Uncontested Stipulated Settlement between the Staff and the parties in that proceeding. That case was initiated by Cleco and SWEPCO to revise the benchmarking formula set forth in the Dolet Hills Order. That formula had failed to properly reflect the costs that would have been incurred under the old DHMV contract (particularly the cost of diesel fuel), thus causing the Companies to defer such large amounts of fuel costs that it was unlikely that those deferrals would ever be collected. The Uncontested Stipulated Settlement resolved this issue by revising the benchmarking formula, maintaining the 2% savings to Louisiana ratepayers, ensuring that the Companies would continue to economically operate the DHPS through 2016, and establishing reporting requirements to enable the Commission and the Staff to monitor costs and deferrals on an ongoing basis. The Order dictated that the benchmarking would end on April 30, 2011. The Companies also agreed to provide the Commission, by May 1, 2010, with a life-of-the-mine forecast for the Dolet Hills lignite mine and the Companies' current estimates of the economic life of the mine.

The Companies also agreed to undertake all necessary activities to extend the expiration date of the mine until 2016. The Commission insisted on this provision because

DHPS has been such an economical power source for the Companies' ratepayers--the incremental cost of electricity being produced out of the Dolet Hill mines has been and remains at or below 2¢/KWH. Originally, the mining of lignite for the Dolet Hills plant was conducted by the DHMV, an independent third party miner. In the late 1990s and early 2000s, significant problems developed with the DHMV, causing Cleco Power and SWEPCO (and ultimately, their ratepayers) to pay higher prices for the lignite than should have been achieved with a more

efficient mining operation. In addition, the DHMV had fallen behind, significantly, in its reclamation obligations which could have resulted in consequences ranging from increased costs, significant potential fines by the Department of Environmental Quality or the Environmental Protection Agency, or even a shutdown of the mine. The latter would have been disastrous both for Cleco Power and SWEPCO, as the incremental cost of electricity being produced using lignite mined from the Dolet Hills reserves is below 2¢/KWH.

On April 30, 2009 in Docket No. U-30975, SWEPCO and Cleco filed an application with the Commission seeking authority to purchase the permit, leases, reserves and equipment associated with a lignite mine known as the Red River Mine-Oxbow Reserve ("Oxbow Mine") owned by North American Coal. The total purchase price for the permit, leases, and reserves is $25.70 million. SWEPCO Miner's cost to purchase the mining equipment is $15.80 million. The all in cost to acquire the permit, leases, reserves and equipment is $41.50 million. The new reserves acquired through the Oxbow Mine purchase will extend life of the Dolet Hills Lignite Unit from 2016-2019 to at least 2026.

In support if its application, Cleco and SWEPCO filed detailed testimony and analyses by several witnesses and provided documentation and data in response to the Staff's requests. Numerous discussions were held between the Staff and the Companies and additional information was provided. The Staff reviewed the information and data supplied by the Companies and has determined that the purchase of the Oxbow mine is prudent, reasonable, continues desired fuel diversity and results in the most economic fuel cost alternative for the DHPS and the lowest reasonable cost for Louisiana ratepayers.

The Commission Staff, Cleco Power, and SWEPCO reached an Uncontested Stipulated Settlement ("Settlement") that resolves all issues arising from the Companies' Application, in LPSC Docket No. U-30975, with respect to that certain Purchase and Sale Agreement, dated April 29, 2009, as amended August 28, 2009, between the Companies and the North American Coal Company (the "PSA"), and governing the sale of the Oxbow Lignite Reserves to Cleco and SWEPCO. The PSA was provided as an attachment to Exhibit 1 to the

Companies' Application filed April 30, 2009. The Application is in the public interest and should be approved subject to the terms and conditions in the Uncontested Stipulated Settlement and including the August 28, 2009, amendment to the PSA.

Subject to the terms and conditions set forth in the Uncontested Stipulated Settlement, the acquisition of the Oxbow Mine is found to be prudent, reasonable, and in the best interest of the Companies' customers. The hearing on the Proposed Uncontested Stipulated Settlement was conducted before the Honorable Michelle Finnegan, the presiding Administrative Law Judge, on September 11, 2009. The principal provisions and impacts of the Settlement are as follows:

1. Subject to the terms and conditions of the Uncontested Stipulated Settlement, the Companies should be authorized to recover all prudently incurred costs through their respective Fuel Adjustment Clauses ("FAC"), rate base, or Formula Rate Plan ("FRP"). The costs of the Oxbow permit, leases, and reserves shall be recovered through base rates. The ongoing costs of lignite production as well as the deferrals described in Paragraphs 3 and 4, shall be recovered through the Companies' FACs.

2. The benchmarking requirements adopted in LPSC Order No. U-21453, U-20925, and U-22092(SC), Subdocket G, and modified in LPSC Order No. U-29797 will be discontinued. However, Dolet Hills Lignite Company ("DHLC" or the SWEPCO Miner") will be required to submit to the Commission, periodically, a variety of data concerning its mining operations and costs as set forth in Paragraph 7, below. The Companies will also be required to comply with the ratepayer protection mechanisms set forth below.

3. The Companies will be permitted to continue to collect legacy deferrals and certain legal costs as approved in Order Nos. U-21453, U-20925 and U22092(SC) and Order No. U-29797. The Companies may charge and collect their existing deferral balances, including interest (as set forth in Paragraph 4, below) as they are accrued, (with SWEPCO recovering its litigation costs without carrying costs) over approximately 9 years for Cleco Power and 1 year for SWEPCO at a fixed monthly amortization with levelized customer impacts, as provided in Order U-29797.

4. The carrying charges on the deferral balances discussed in Paragraph 3 shall be calculated at each Company's cost of short term debt, defined for this purpose in the case of Cleco Power as the cost of funds under its revolving credit agreement for general corporate purposes, and defined for this purpose in the case of SWEPCO as its costs of funds under the AEP money pool, as provided in Order U-29797.

5. The manner of determining the management fee adopted in Order No. U-29797 shall be continued. The SWEPCO Miner (DHLC) will be authorized to charge and collect a management fee of $0.0616/MMBTU for the first 35 million MMBTUs delivered and $0.0516/MMBTU for the first 35 million MMBTUs delivered and $0.0516/MMBTU for all overage tonnage delivered, subject to GDP-IPD escalation (Second Quarter, first published). All prudently incurred lignite production costs of DHLC, including, but not limited to: depreciation, carrying cost, management fee, operations and maintenance expense, insurance, taxes, reclamation accrual, and prudently incurred post production costs, will be recovered in the respective Company's LPSC FAC.

6. The Companies should be permitted the opportunity to recover the investments in the Oxbow permit, leases and reserves through base rates or Formula Rate Plan proceedings filed with the Commission.

7. The Commission approves the Oxbow acquisition, subject to the following conditions.

   a. The Companies shall file the following performance data for the Dolet Hills Power Station on a yearly basis: (i) availability factor, (ii) capacity factor, (iii) fuel costs in $/Mmbtu and $/kWh, (iv) total fuel cost per kWh for DHPS versus all other plants for both SWEPCO and Cleco.

   b. The Companies shall perform and file annually a report that summarizes the tonnage and production cost estimates for both the Dolet Hills and Oxbow lignite mines. Subsequent annual filings shall include the tonnage actually mined from each mine and the actual overall weighted cost of the lignite at the end of each year. This shall not prevent the Commission or its Staff from requesting additional information and analyses and the Companies commit to make good faith efforts to provide the information and/or analyses requested.

   c. The Companies shall file a yearly report of the amount of lignite that is sold from the Oxbow Mine to: (1) Cleco for Rodemacher Power Station Unit 3, (or any unit other than the Dolet Hills unit) and (2) all other parties. The report should include the date of each sale, the amounts sold in each transaction, the price paid per ton for each of the sales and the margins earned on each of those sales. All of the revenues derived from these sales must be flowed through to the Companies' customers, dollar for dollar, through their respective FACs. The report should also reflect the amounts and timing of those flow-throughs.

   d. The Companies shall commit to continue the operation of the Dolet Hills plant and mines in order that they will be used and useful and in the public interest through at least 2026. The Companies shall commit to undertake all reasonable and prudent actions and make the reasonable expenditures necessary to extend the life of mining operations to at least 2026. The Companies' commitment to extend the life of mining operations to 2026 is contingent upon

such continued operation being prudent, considering economic, environmental, operational or other similar factors, as well as continued LPSC authorization of a reasonable opportunity for the Companies' recovery of their prudently incurred mining costs by means of the Commission's FAC General Order. The Companies shall not be precluded from applying to the Commission for a shortening of the time requirement, based upon such continued operation no longer being prudent, considering economic, environmental, operational or other similar factors, or based upon the Commission's denial of the opportunities for the Companies to recover their prudently incurred mining costs in their FACs.

e. By October 1, 2010, the Companies shall submit to LPSC Staff: (i) their life-of-the-mine forecasts for the Dolet Hills and Oxbow Mines, and (ii) the Companies' calculations and supporting reasoning for the Companies' then current estimates of the remaining economic life of the Dolet Hills and Oxbow Mines, relative to the year 2026. With respect to item (ii), the Companies shall cooperate and consult with LPSC Staff in reviewing any potential requests by the Companies to shorten or extend the 2026 date specified in paragraph 7 (d), above.

f. Consistent with the requirements of Order No. U-21453, U-20925(SC), and U-22092(SC), Subdocket G, the Commission shall continue to have access to the books and records of SWEPCO, the SWEPCO Miner, AEP Services, and Cleco relating to the mining operations of DHLC at the Dolet Hills and Oxbow Mines.

g. The reports required to be submitted pursuant to this Settlement on an annual basis shall be submitted by March 1 of the succeeding year. Those reports to be submitted quarterly shall be submitted no later than 30 days after the end of each quarter.

8. The Companies' commitment to operate Dolet Hills, if economic, through 2026 should provide continued significant savings to Cleco Power and SWEPCO ratepayers.

9. Nothing in the Settlement or in this Order approving this Settlement in any way diminishes or alters the Commission's jurisdiction, authority or rights pursuant to its General Order regarding Fuel Adjustment Clauses.

10. Nothing in the Settlement or in this Order approving this Settlement diminishes or alters the Commission's jurisdiction, authority or rights to conduct any analyses regarding the ongoing mining and fuel procurement activities or fuel costs of DHLC, Cleco or SWEPCO.

11. Nothing in the Settlement or in this Order approving this Settlement shall constitute pre-approval of any of the ongoing mining and fuel procurement activities or fuel costs of DHLC, Cleco or SWEPCO.

12. With the exception of the decision to acquire the Oxbow mine permit, leases and reserves, nothing in the Settlement or in this Order approving this Settlement shall constitute a finding of prudence of any of the ongoing mining and fuel procurement activities or fuel costs of DHLC, Cleco or SWEPCO.

13. All of the provisions of LPSC Order No. U-21453, U-20925, and U-22092 (SC) Subdocket G and Order U-29797 that have not been explicitly changed by, or are not inconsistent with this Order approving the

Settlement, shall remain in full force and effect, including ordering paragraph 3 of the 2001 order, which shall apply to the SWEPCO Miner's financing of its acquisition of the assets and rights of NAC, rather than DHMV.

14. This Settlement shall have no precedential effect in any future proceedings involving issues similar to those resolved herein, and shall be without prejudice to the right of any party to take any position on any such similar issues in future proceedings, or appeals therefrom.

IV. CONCLUSION

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As set forth above, and considering the record, the Commission determines that the Proposed Uncontested Stipulated Settlement, while causing a small incremental increase in the cost of fuel for both Cleco Power and SWEPCO, is fair both to customers and the Companies, will produce just, reasonable and not unduly discriminatory rates, and is in the public interest.

Upon Motion of Commissioner Campbell, seconded by Commissioner Skrmetta, and unanimously adopted at the Commission's September 16, 2009 Business & Executive Session, the Commission orders the following:

IT IS HEREBY ORDERED that:

A. The Proposed Uncontested Stipulated Settlement entered into by the Staff and the Companies, is in the public interest, is fair to ratepayers and the Companies, will produce just, reasonable and not unduly discriminatory rates, and is hereby approved by the Commission. The Proposed Uncontested Stipulated Settlement is attached and made a part of this Order as Exhibit 1 and includes the following findings and terms.

1. Subject to the terms and conditions of the Uncontested Stipulated Settlement, the Companies are authorized to recover all prudently incurred costs through their respective Fuel Adjustment Clauses ("FAC"), rate base, or Formula Rate Plan ("FRP"). The costs of the Oxbow permit, leases, and reserves shall be recovered through base rates. The ongoing costs of lignite production, as well as the deferrals described in Paragraphs 3 and 4, shall be recovered through the Companies' FACs.

2. The benchmarking requirements adopted in LPSC Order No. U-21453, U-20925, and U-22092(SC), Subdocket G, and modified in LPSC Order No. U-29797 are discontinued. However, Dolet Hills Lignite Company ("DHLC" or the SWEPCO Miner") will be required to submit to the Commission, periodically, a variety of data concerning its mining operations and costs as set forth in Paragraph 7, below. The Companies will also be required to comply with the ratepayer protection mechanisms set forth below.

3. The Companies will be permitted to continue to collect legacy deferrals and certain legal costs as approved in Order Nos. U-21453, U-20925 and U22092(SC) and Order No. U-29797. The Companies may charge and

collect their existing deferral balances, including interest (as set forth in Paragraph 4, below) as they are accrued, (with SWEPCO recovering its litigation costs without carrying costs) over approximately 9 years for Cleco Power and 1 year for SWEPCO at a fixed monthly amortization with levelized customer impacts, as provided in Order U-29797.

4. The carrying charges on the deferral balances discussed in Paragraph 3 shall be calculated at each Company's cost of short term debt, defined for this purpose in the case of Cleco Power as the cost of funds under its revolving credit agreement for general corporate purposes, and defined for this purpose in the case of SWEPCO as its costs of funds under the AEP money pool, as provided in Order U-29797.

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5. The manner of determining the management fee adopted in Order No. U-29797 shall be continued. The SWEPCO Miner (DHLC) is authorized to charge and collect a management fee of $0.0616/MMBTU for the first 35 million MMBTUs delivered and $0.0516/MMBTU for all overage tonnage delivered, subject to GDP-IPD escalation (Second Quarter, first published). All prudently incurred lignite production costs of DHLC, including, but not limited to: depreciation, carrying cost, management fee, operations and maintenance expense, insurance, taxes, reclamation accrual, and prudently incurred post production costs, will be recovered in the respective Company's LPSC FAC.

6. The Companies are permitted the opportunity to recover the investments in the Oxbow permit, leases and reserves through base rates or Formula Rate Plan proceedings filed with the Commission.

7. The Commission approves the Oxbow acquisition, subject to the following conditions.

   a. The Companies shall file the following performance data for the Dolet Hills Power Station on a yearly basis: (i) availability factor, (ii) capacity factor, (iii) fuel costs in $/Mmbtu and $/kWh, (iv) total fuel cost per kWh for DHPS versus all other plants for both SWEPCO and Cleco.

   b. The Companies shall perform and file annually a report that summarizes the tonnage and production cost estimates for both the Dolet Hills and Oxbow lignite mines. Subsequent annual filings shall include the tonnage actually mined from each mine and the actual overall weighted cost of the lignite at the end of each year. This shall not prevent the Commission or its Staff from requesting additional information and analyses and the Companies commit to make good faith efforts to provide the information and/or analyses requested.

   c. The Companies shall file a yearly report of the amount of lignite that is sold from the Oxbow Mine to: (1) Cleco for Rodemacher Power Station Unit 3, (or any unit other than the Dolet Hills unit) and (2) all other parties. The report should include the date of each sale, the amounts sold in each transaction, the price paid per ton for each of the sales and the margins earned on each of those sales. All of the revenues derived from these sales must be flowed through to the Companies' customers, dollar for dollar, through their respective FACs. The report should also reflect the amounts and timing of those flow-throughs.

d. The Companies shall commit to continue the operation of the Dolet Hills plant and mines in order that they will be used and useful and in the public interest through at least 2026. The Companies shall commit to undertake all reasonable and prudent actions and make the reasonable expenditures necessary to extend the life of mining operations to at least 2026. The Companies' commitment to extend the life of mining operations to 2026 is contingent upon such continued operation being prudent, considering economic, environmental, operational or other similar factors, as well as continued LPSC authorization of a reasonable opportunity for the Companies' recovery of their prudently incurred mining costs by means of the Commission's FAC General Order. The Companies shall not be precluded from applying to the Commission for a shortening of the time requirement, based upon such continued operation no longer being prudent, considering economic, environmental, operational or other similar factors, or based upon the Commission's denial of the opportunities for the Companies to recover their prudently incurred mining costs in their FACs.

e. By October 1, 2010, the Companies shall submit to LPSC Staff: (i) their life-of-the-mine forecasts for the Dolet Hills and Oxbow Mines, and (ii) the Companies' calculations and supporting reasoning for the Companies' then current estimates of the remaining economic life of the Dolet Hills and Oxbow Mines, relative to the year 2026. With respect to item (ii), the Companies shall cooperate and consult with LPSC Staff in reviewing any potential requests by the Companies to shorten or extend the 2026 date specified in paragraph 7 (d), above.

f. Consistent with the requirements of Order No. U-21453, U-20925(SC), and U-22092(SC), Subdocket G, the Commission shall continue to have access to the books and records of SWEPCO, the SWEPCO Miner, AEP Services, and Cleco relating to the mining operations of DHLC at the Dolet Hills and Oxbow Mines.

g. The reports required to be submitted pursuant to this Settlement on an annual basis shall be submitted by March 1 of the succeeding year. Those reports to be submitted quarterly shall be submitted no later than 30 days after the end of each quarter.

8. All of the provisions of LPSC Order No. U-21453, U-20925, and U-22092 (SC) Subdocket G and Order U-29797 that have not been explicitly changed by, or are not inconsistent with this Order approving the Settlement shall remain in full force and effect, including ordering paragraph 3 of the 2001 order, which shall apply to the SWEPCO Miner's financing of its acquisition of the assets and rights of NAC, rather than DHMV.

B. SWEPCO and Cleco Power shall be required to take all other actions and make all other filings required by the Stipulated Settlement and this Order.

BY ORDER OF THE COMMISSION
BATON ROUGE, LOUISIANA
September 30, 2009

/S/ LAMBERT C. BOISSIERE, III
DISTRICT III
CHAIRMAN LAMBERT C. BOISSIERE, III

/S/ JAMES M. FIELD
DISTRICT II
VICE CHAIRMAN JAMES M. FIELD

/S/ FOSTER L. CAMPBELL
DISTRICT V
COMMISSIONER FOSTER L. CAMPBELL

/S/ ERIC F. SKRMETTA
DISTRICT I
COMMISSIONER ERIC F. SKRMETTA

EVE KAHAO GONZALEZ
SECRETARY

/S/ CLYDE C. HOLLOWAY
DISTRICT IV
COMMISSIONER CLYDE C. HOLLOWAY

PUC DOCKET NO. 46416
SOAH DOCKET NO. 473-17-0647

APPLICATION OF ENTERGY TEXAS, INC. TO AMEND ITS CERTIFICATE OF CONVENIENCE AND NECESSITY TO CONSTRUCT MONTGOMERY COUNTY POWER STATION IN MONTGOMERY COUNTY	**§ § § § § § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the application of Entergy Texas, Inc. (ETI) to amend a certificate of convenience and necessity (CCN) to construct a 993 megawatt (MW) nameplate capacity combined cycle gas turbine (CCGT) facility in Montgomery County. An unopposed stipulation and settlement agreement was executed that resolves all issues in this proceeding between the parties. Consistent with the agreement, ETI's application is approved.

The Commission adopts the following findings of fact and conclusions of law:

I. Findings of Fact

Procedural History

1. ETI is an investor-owned electric utility providing retail electric service in Southeast Texas under CCN No. 30076.

2. On October 7, 2016, ETI filed an application to amend a CCN to construct the Montgomery County Power Station (MCPS or Project), a 993 MW CCGT facility, near Willis, Texas, for an estimated cost of $937.3 million (inclusive of $826.3 million of generation project capital costs and $111 million of transmission project capital costs).

3. ETI's application included the direct testimony of 15 witnesses.

4. On October 7, 2016, ETI provided notice of this proceeding to all the parties to ETI's most recent base rate case, Docket No. 41791[1] and to the Office of Public Utility Counsel (OPUC) by hand delivery. On October 11, 2016, ETI provided written notice of the

[1] *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs,* Docket No. 41791, Order (May 16, 2014).

application to the cities of Conroe, Willis, and Panorama Village, which are the municipalities within five miles of the proposed facility. On October 11, 2016, ETI mailed notice of the application to the County Judge in Montgomery County. There were no directly affected landowners as defined in 16 Texas Administrative Code § 22.52(a)(3) (TAC).

5. On October 7, 2016, Merrimack Energy Group, Inc. filed a notice of appearance and the direct testimony of Wayne J. Oliver as an independent monitor for ETI's request for proposals that resulted in the selection of MCPS.

6. On October 11, 2016, the Commission referred this proceeding to the State Office of Administrative Hearings (SOAH).

7. ETI published notice in newspapers of general circulation in ETI's service area on September 28, October 5, 12, and 19, 2016. Publishers' affidavits were filed on November 3, 2016.

8. On October 13, 2016, ETI provided a copy of the Environmental Assessment to the Texas Parks & Wildlife Department (TPWD).

9. On October 20, 2016, SOAH issued Order No. 1, describing the filing, noticing an initial prehearing conference, and granting pending motions to intervene filed by Texas Industrial Energy Consumers (TIEC) and the OPUC.

10. On October 26, 2016, SOAH issued Order No. 2, revising the date for the prehearing conference and granting motions to intervene filed by the Cities of Anahuac, Beaumont, Bridge City, Cleveland, Conroe, Dayton, Groves, Houston, Huntsville, Liberty, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, and West Orange (collectively, Cities) and East Texas Electric Cooperative, Inc. (ETEC).

11. On November 10, 2016, SOAH issued Order No. 3, memorializing the prehearing conference, adopting an agreed procedural schedule, noticing a hearing on the merits, approving the form of notice, granting ETI's motion for admission *pro hac vice*, and adopting the form of a protective order.

12. On November 14, 2016, the Commission issued a preliminary order identifying the issues to be addressed in this docket.

13. On December 8, 2016, SOAH issued Order No. 4, granting a motion to intervene filed by Wal-Mart Stores, Inc. and Texas Retail Energy, LLC (collectively, Wal-Mart Group).

14. On December 8, 2016, ETI filed proof of notice.

15. On December 9, 2016, comments from TPWD were filed in this docket, but the comments were not admitted into evidence. TPWD did not seek to intervene in this proceeding.

16. ETI filed errata to the application and direct testimony on December 9 and 19, 2016, and on February 2 and 23, 2017.

17. On December 16, 2016, ETI filed supplemental direct testimony.

18. On February 23, 2017 ETI filed notice of substitution of direct testimony.

19. On March 31, 2017, TIEC filed direct testimony.

20. On April 28, 2017, ETI and Merrimack Energy filed rebuttal testimony.

21. The following municipalities filed comments or resolutions supporting ETI's application: City of Hardin, City of Colmesneil, City of Huntsville, City of Bremond, City of Bredias, City of Franklin, City of Daisetta, and the City of Chester. Comments supporting ETI's application were also filed by the Chambers of Commerce of Huntsville, Walker County, and Silsbee. These comments were not admitted as evidence.

22. On June 14, 2017, ETI filed an agreement resolving all issues in this proceeding. The agreement recommends that ETI's request for a CCN amendment be granted so that ETI may build, own, and operate MCPS. ETI, Commission Staff, OPUC, and TIEC are signatories to the agreement (collectively, signatories). The following parties are not signatories to the agreement, but are unopposed to the agreement: Cities, ETEC and Wal-Mart Group.

23. On June 19, 2017, SOAH issued SOAH Order No. 8, admitting evidence, returning the case to the Commission, and dismissing the proceeding from the SOAH docket.

Description of the Agreement

CCN Approval

24. The signatories agreed that the Commission should amend ETI's CCN No. 30076 to allow ETI to build, own, and operate MCPS, consistent with ETI's application and the terms of agreement.

Cost Controls for MCPS Generation Capital Costs

25. The Signatories agreed that MCPS generation project capital costs eligible for recovery from ETI's ratepayers are limited to $830.8 million (comprised of $103.8 million of allowance for funds used during construction (AFUDC) and $727 million of non-AFUDC costs). The following costs are specifically excluded from the generation capital cost cap: (a) costs of transmission upgrades required for MCPS, (b) costs arising out of a Force Majeure event, including AFUDC costs, and (c) increases of AFUDC except for the portion related to non-AFUDC costs over the cap and not attributed to a Force Majeure event.

Force Majeure

26. "Force Majeure," as used in the agreement, means an event or circumstance that is not reasonably foreseeable or avoidable, and not within the reasonable control or due to the fault or negligence of ETI or its contractors or subcontractors for the MCPS (collectively, Contractors). Subject to the above, Force Majeure includes, without limitation: (a) acts of God; floods; natural disasters; landslides; droughts; tornadoes; hurricanes; tsunamis; hail; ice storms; lightning; other severe storms (except as provided below); earthquakes; fires; explosions; acts of the public enemy; terrorism; vandalism; riots; blockades; sabotage (except as provided below); civil disturbances; war (declared or not) and other armed conflicts or mobilizations; national emergency; and epidemics; (b) strikes, stoppages, and labor disturbances (even if such labor difficulties could be resolved by conceding to the demands of a labor group); (c) shortages in labor, commodities, equipment, materials, or other goods or services arising out of force majeure events; (d) the bankruptcy or insolvency of a material Contractor; (v) the adoption, amendment, issuance, promulgation, or repeal of or other change in, or in the interpretation or application of, applicable laws; and (e) any action or inaction by any governmental authority (including, without limitation, failure or refusal by any regulatory or other governmental authority to act upon or grant

permits, licenses, approvals, or authorizations or delays in acting or granting by such authorities). For the avoidance of doubt, an event or circumstance constituting a Force Majeure as defined above is a Force Majeure even if it occurs outside of the MCPS project site.

27. Force Majeure expressly excludes: (a) the mechanical failure or breakage of, or damage to, equipment, systems, or other items to be included in the MCPS, except to the extent arising out of Force Majeure; (b) a breakdown or defect in equipment or other items provided by ETI or a Contractor to construct the MCPS, except to the extent arising out of a Force Majeure; (c) sabotage at the MCPS project site by employees of ETI or a Contractor; and (d) normal rain or inclement weather days.

Prudence of Sabine 2 Deactivation

28. The signatories agreed that ETI will present evidence in its next fuel reconciliation or base rate proceeding, whichever is filed first, supporting the prudence of ETI's decision to deactivate Sabine Unit 2, a 213 MW gas-fired steam unit located in the West of the Atchafalaya Basin planning region.

Statutory CCN Issues

Adequacy of Existing Service

29. ETI is currently providing adequate service to its customers.

Need for Additional Service

30. ETI has a need for the additional capacity and energy that would be provided by MCPS.

31. ETI expects that MCPS will operate at heat rates that are approximately 30% lower than ETI's existing generators.

32. ETI expects that MCPS will produce energy at a cost much lower than the expected market clearing prices for energy required to serve ETI's load, yielding fuel cost savings for ETI customers.

33. ETI has an identified need for local voltage support. The addition of MCPS in ETI's Western Region will provide reactive power support to the region, which is critical to transmission system reliability.

34. MCPS is a reasonable alternative to meet ETI's identified capacity and energy needs.

Effect of the CCN Request on ETI and any Electric Utility Serving the Area

35. Granting a CCN for MCPS will enhance ETI's ability to procure long-term capacity, energy, and voltage support at a reasonable cost.

36. MCPS is not expected to adversely impact ETI's long-term financial health.

37. MCPS will not be located within the certificated service area of any other utility. MCPS will be located within ETI's service area at its existing Lewis Creek facility.

38. ETEC is the only utility in the area that intervened. ETEC does not oppose the agreement or entry of a final order consistent with the terms.

Community Values

39. Conroe, Willis, and Panorama Village, which are the three municipal entities within five miles of MCPS, were provided notice of this proceeding and none opposed ETI's application.

40. MCPS will support regional economic growth through the availability of reasonably priced power, and is expected to provide economic benefits to the region through direct monetary investment and the creation of temporary and permanent jobs.

41. ETI's Lewis Creek site, where MCPS will be constructed and operated, has been a fixture in the local area since 1970.

42. MCPS is not expected to adversely impact community values.

Recreational and Park Areas

43. There are no public parks or recreational areas within two miles of MCPS.

44. Construction of MCPS will have no adverse impact on recreational or park areas.

Historical and Aesthetic Values

45. Based on the Environmental Assessment filed in this docket, there are no known archaeological or historic features in the nearby vicinity that would be adversely affected by construction and operation of MCPS.

46. While clearing of vegetation will be needed to support MCPS construction activities, there will be no major or noticeable shift in land use in the area since the site is already primarily industrial due to the presence of the Lewis Creek facility, which began operation in 1970, and the adjacent Clean Energy Texas LNG plant.

47. Construction and operation of MCPS will have no significant impact on historical or aesthetic values.

Environmental Integrity

48. Since MCPS will be constructed at an existing industrial plant site, it will not significantly impact the environmental integrity of the area.

49. Although the MCPS site abuts the Lewis Creek Reservoir, Federal Emergency Management Agency Flood Hazard Maps indicate that the project site is not within the Reservoir's 100-year floodplain. A wetland delineation and waterbody survey indicates that there are no wetlands present on the Project site.

50. MCPS will use natural gas for fuel and air emissions will be permitted by the Texas Commission on Environmental Quality (TCEQ). Best Available Control Technology for attainment pollutants and Lowest Achievable Emissions Rate control technology for nonattainment pollutants will be applied to the Project emission sources. Impacts from operation of the Project's facility will be mitigated through control technology to reduce emissions and stack design and location to reduce air quality impacts. The combustion turbines will use dry low-NOx combustion controls to reduce NOx emissions. The Heat Recovery Steam Generator stacks will use aqueous ammonia injection and selective catalytic reduction to further control NOx emissions. Good combustion practices and a carbon monoxide (CO) catalyst will reduce CO emissions. The fuel selection of pipeline quality natural gas will reduce particulate matter and sulfur dioxide emissions. Drift eliminators will reduce particulate matter emissions from the cooling towers.

51. Energy efficient combined cycle operation and natural gas fuel will significantly reduce greenhouse gas emissions and serve as the control technologies for greenhouse gas emissions. MCPS air emissions will be modeled, using Environmental Protection Agency (EPA) and TCEQ-approved air dispersion modeling software, guidance procedures and

protocols, to demonstrate acceptable air quality impacts against the National Ambient Air Quality Standards.

52. MCPS is being designed in accordance with all water discharge regulatory requirements. The existing Lewis Creek Plant operates under a valid Texas Pollutant Discharge Elimination System (TPDES) permit and will continue to operate under a renewed/modified TPDES permit upon issuance, which will incorporate all discharges from MCPS. The issuance of this permit, and ETI's continued compliance, will minimize any water quality impacts.

53. ETI will implement a plan to protect any nesting species at the MCPS site, including construction areas. A species management plan will be developed and implemented in the event any protected species are discovered during construction. ETI will evaluate the efficacy of post-construction, revegetation options on the MCPS site consistent with storm water erosion and sediment control planning. Disturbed areas of the Project that are not eventually developed will be revegetated following construction activities. The project will also follow standards and best management practices set forth by Rule 316b of the U.S. Environmental Protection Agency Clean Water Act, which will minimize the potential harm and mortality of aquatic species that could be entrained or impinged within the Project cooling water intake structure.

54. There are no agricultural operations near the MCPS site. Thus, construction of MCPS will have no impact on agriculture.

55. The construction of the Project will temporarily disturb approximately 50 acres of land on the existing Lewis Creek site. Standard construction equipment will be used to prepare the Project site for construction. The use of this construction equipment will physically disturb underlying soils, which could result in soil compaction, reducing the porosity and conductivity of the soil. Such compaction may slightly increase the amount of surface runoff in the immediate area during construction. To mitigate the effects of construction equipment physically disturbing underlying soils, construction equipment will travel over temporary gravel roads and will be stored on an offsite paved parking area directly adjacent

to the Project site. No ground disturbance outside the 50 acres of the Project site is anticipated.

56. No additional public roads will be built for plant access or construction of MCPS.

57. There will be a temporary increase in noise during the construction period. The existing Lewis Creek facility and/or the Clean Energy Texas LNG plant will provide a buffer between the Project site and the nearest residences. ETI will manage construction in a manner that implements appropriate noise control measures.

Probable Improvement of Service or Lowering of Cost to Consumers if the CCN is Granted

58. ETI's Western Region, located within the West of the Atchafalaya Basin planning region, is a region of heavy load concentration, which, due to a limit in the ability to import power into the region, is dependent upon generation capability located within the region to serve the load in the region. The Western Region is also vulnerable to serious storms and the average age of in-region gas-fired steam generation will be over 50 years in 2021.

59. MCPS will provide a modern generating unit that will reduce reliance on existing, aging gas-fired generation and mitigate exposure to increased transmission costs.

60. MCPS will support power restoration efforts in the event of transmission line outages, as may occur following major weather events, and help maintain reliable service and system stability in the event of forced outages of the older, existing units operating within the Western Region.

61. ETI expects that the addition of MCPS in the Western Region will provide reactive power support to the region, which is critical to transmission system reliability.

62. MCPS will enhance the reliability of service to customers by its placement and operation in the Western Region.

63. ETI expects that MPCS will reduce locational marginal prices.

Effect, if any, of Granting a CCN on Ability of State to Meet PURA § 39.904(a) Goal for Adding Renewable Resources

64. Granting a CCN for MCPS will have no effect on the ability of the State to meet the goal established by PURA[2] § 39.904(a). The addition of new generation will not affect ETI's retail sales or corresponding Renewable Energy Credit obligation.

Is the CCN Necessary for Service, Accommodation, Convenience, or Safety of the Public

65. Considering all the factors discussed above, ETI's requested CCN amendment to build, own, and operate MCPS is necessary for the service, accommodation, convenience, or safety of the public.

Informal Disposition

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

67. The proposed resolution of this docket set forth in the agreement is not adverse to any party.

68. No protests or requests for hearing have been filed and no issues of fact or law are disputed by any party; therefore, no hearing is necessary.

II. Conclusions of Law

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

2. The Commission has jurisdiction over this matter in accordance with PURA §§ 14.001, 37.051(a), 37.053, 37.056, 37.058(b), and 39.452(j).

3. ETI provided proper notice of the application in compliance with PURA § 37.054 and 16 TAC § 22.52(a).

4. This docket was processed in accordance with the requirements of PURA, the Administrative Procedure Act,[3] and Commission rules.

5. ETI is entitled to approval of the application described in the findings of fact, having demonstrated that the proposed MCPS project is necessary for the service, accommodation,

[2] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-58.303 (West 2016), §§ 59.001-66.017 (West 2007 & Supp. 2016) (PURA).

[3] Tex. Gov't Code Ann. § 2001.001-.902 (West 2016) (APA).

convenience, or safety of the public within the meaning of PURA § 37.056(a), taking into consideration the factors set out in PURA § 37.056(c), and satisfies ETI's identified reliability needs within the meaning of PURA § 39.452(j).

6. The application may be approved without a hearing under to § 2001.056 of the APA.

7. This application does not constitute a major rate proceeding as defined by 16 TAC § 22.2.

8. The requirements for informal disposition under 16 TAC § 22.35 have been met in this proceeding.

III. Ordering Paragraphs

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

1. Consistent with the agreement, ETI's application is approved.

2. ETI's CCN No. 30076 is amended to include the construction, ownership, and operation of the proposed MCPS project, a 993 MW nameplate capacity CCGT facility to be located in Montgomery County.

3. Consistent with the agreement, MCPS generation project capital costs eligible for recovery from ETI's ratepayers are limited to $830.8 million (comprised of $103.8 million of allowance for AFUDC and $727 million of non-AFUDC costs). The following costs are specifically excluded from the generation capital cost cap: (a) costs of transmission upgrades required for MCPS, (b) costs arising out of a Force Majeure event (as defined above), including AFUDC costs, and (c) increases of AFUDC except for the portion related to non-AFUDC costs over the cap and not attributed to a Force Majeure event (as defined above).

4. Consistent with the agreement, ETI shall present evidence in its next fuel reconciliation or base rate proceeding, whichever is filed first, supporting the prudence of ETI's decision to deactivate Sabine Unit 2, a 213 MW gas-fired steam unit located in the West of the Atchafalaya Basin planning region.

5. Resolution of this docket was the product of negotiation and compromise between the Parties. Entry of this Order does not indicate the Commission's endorsement or approval

of any principle or methodology that may underlie the agreement. Entry of this Order shall not be regarded as binding holding or precedent as to the appropriateness of any principle or methodology underlying the agreement.

6. In the event ETI or its contractors encounter any artifacts or other cultural resources during project construction, work shall cease immediately in the vicinity of the resource and the discovery shall be reported to the Texas Historical Commission (THC). In that situation, ETI shall take action as directed by the THC.

7. ETI shall implement erosion control measures as appropriate.

8. ETI shall implement a plan to protect any nesting species at the MCPS site, including construction areas.

9. ETI shall minimize the amount of flora and fauna disturbed during construction. In addition, ETI shall revegetate, with native species, any disturbed areas of the Project site that are not eventually developed. Furthermore, to the maximum extent practicable, ETI shall avoid adverse environmental impacts to sensitive plant and animal species and their habitats as identified by TPWD and the United States Fish and Wildlife Service.

10. ETI will identify any additional permits that are necessary, will consult any required agencies, will obtain all necessary environmental permits, and will comply with the relevant permit conditions during construction and operation of MCPS.

11. All other motions, requests for entry of specific findings of fact, conclusions of law, and ordering paragraphs, and any other requests for general or specific relief, if not expressly granted, are denied.

Signed at Austin, Texas the _____ day of July 2017.

PUBLIC UTILITY COMMISSION OF TEXAS

_____
KENNETH W. ANDERSON, JR., COMMISSIONER

_____
BRANDY MARTY MARQUEZ, COMMISSIONER

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Control Number: 51215

Item Number: 275

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,

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.

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[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.

Adequacy of Existing Service, Need for Additional Service, Probable Improvement of Service and Reliability

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.