UNIVERSAL NATURAL GAS, LLC D/B/A UNIVERSAL NATURAL GAS, INC.

RATE SCHEDULE - LINE EXTENSION POLICY

Line Extension and/or Re-Route Policy: Actual Cost

Gas main, service line, and yard line installations, re-routes, or extensions shall be made at Company's expense only where the probable use of all facilities necessary for such service will provide a reasonable and compensatory return to Company on the value of such facilities. In all other cases, Company may require, on a consistent and non-discriminatory basis, pre-payment, reimbursement, or adequate security for all Actual Cost of extending its existing pipeline system to serve a new customer. "Yard line" includes customer-owned gas lines installed on customer's side of the meter at customer request. Such gas line extensions shall be made only under the following conditions:

A. Individual Residential – Company shall only be required to extend distribution mains up to fifty (50) feet for any individual residential customer if such customer, at a minimum, uses gas for unsupplemented space heating and water heating or an equivalent load. Tapping of Company main and any length of gas mains in excess of the first 50 feet, or service lines, yard lines, and meter set required for the establishment of service, shall be charged to customer at Actual Cost.

B. Developers of Residential and/or Business Subdivisions -- upon execution of Company's Natural Gas System Development and Distribution Agreement, or under special circumstances where, in Company's opinion, such form is not appropriate, upon execution of a special agreement providing for satisfactory conditions for reimbursement to Company for Company's Actual Cost of the necessary gas line extension(s) and related facilities, including gas mains, service lines, meters and regulators.

C. Other Commercial or other non-residential locations – Tapping of Company main and any length of gas mains, services lines, or yard lines required for the establishment of service shall be charged to customer at Actual Cost.

UNIVERSAL NATURAL GAS, LLC D/B/A UNIVERSAL NATURAL GAS, INC.

RATE SCHEDULE QSR - QUALITY OF SERVICE

RULE Section 7.45 Quality of Service (as supplemented herein);

For gas utility service to residential and small commercial customers, the following minimum service standards shall be applicable in unincorporated areas. In addition, each gas distribution utility is ordered to amend its service rules to include said minimum service standards within the utility service rules applicable to residential and small commercial customers within incorporated areas, but only to the extent that said minimum service standards do not conflict with standards lawfully established within a particular municipality for a gas distribution utility. Said gas distribution utility shall file service rules incorporating said minimum service standards with the Railroad Commission and with the municipalities in the manner prescribed by law.

(1) Continuity of service.

(A) Service interruptions.

(i) Every gas utility shall make all reasonable efforts to prevent interruptions of service. When interruptions occur, the utility shall reestablish service within the shortest possible time consistent with prudent operating principles so that the smallest number of customers are affected.

(ii) Each utility shall make reasonable provisions to meet emergencies resulting from failure of service, and each utility shall issue instructions to its employees covering procedures to be followed in the event of an emergency in order to prevent or mitigate interruption or impairment of service.

(iii) In the event of national emergency or local disaster resulting in disruption of normal service, the utility may, in the public interest, interrupt service to other customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

(B) Record of interruption. Except for momentary interruptions which do not cause a major disruption of service, each utility shall keep a complete record of all interruptions, both

emergency and scheduled. This record shall show the cause of interruptions, date, time duration, location, approximate number of customers affected, and, in cases of emergency interruptions, the remedy and steps taken to prevent recurrence.

(C) Report to commission. The commission shall be notified in writing within 48 hours of interruptions in service affecting the entire system or any major division thereof lasting more than four hours. The notice shall also state the cause of such interruptions. If any service interruption is reported to the commission otherwise (for example, as a curtailment report or safety report), such other report is sufficient to comply with the terms of this paragraph.

(2) Customer relations.

(A) Information to customers. Each utility shall:

(i) maintain a current set of maps showing the physical locations of its facilities. All distribution facilities shall be labeled to indicate the size or any pertinent information which will accurately describe the utility's facilities. These maps, or such other maps as may be required by the regulatory authority, shall be kept by the utility in a central location and will be available for inspection by the regulatory authority during normal working hours. Each business office or service center shall have available up-to-date maps, plans, or records of its immediate area, with such other information as may be necessary to enable the utility to advise applicants and others entitled to the information as to the facilities available for serving that locality;

(ii) assist the customer or applicant in selecting the most economical rate schedule;

(iii) in compliance with applicable law or regulations, notify customers affected by a change in rates or schedule or classification;

(iv) post a notice in a conspicuous place in each business office of the utility where applications for service are received informing the public that copies of the rate schedules and rules relating to the service of the utility as filed with the commission are available for inspection;

(v) upon request inform its customers as to the method of reading meters;

(vi) provide to new customers, at the time service is initiated or as an insert in the first billing, a pamphlet or information packet containing the following information. This information shall be provided in English and Spanish as necessary to adequately inform the customers; provided, however, the regulatory authority upon application and a showing of good cause may exempt the utility from the requirement that the information be provided in Spanish:

(I) the customer's right to information concerning rates and services and the customer's right to inspect or obtain at reproduction cost a copy of the applicable tariffs and service rules;

(II) the customer's right to have his or her meter checked without charge under paragraph (7) of this section, if applicable;

(III) the time allowed to pay outstanding bills;

(IV) grounds for termination of service;

(V) the steps the utility must take before terminating service;

(VI) how the customer can resolve billing disputes with the utility and how disputes and health emergencies may affect termination of service;

(VII) information on alternative payment plans offered by the utility;

(VIII) the steps necessary to have service reconnected after involuntary termination;

(IX) the appropriate regulatory authority with whom to register a complaint and how to contact such authority;

(X) the hours, addresses, and telephone numbers of utility offices where bills may be paid and information may be obtained; and

(XI) the customer's right to be instructed by the utility how to read his or her meter;

(vii) at least once each calendar year, notify customers that information is available upon request, at no charge to the customer, concerning the items listed in clause (vi)(I) - (XI) of this subparagraph. This notice may be accomplished by use of a billing insert or a printed statement upon the bill itself.

(B) Customer complaints. Upon complaint to the utility by residential or small commercial customers either at its office, by letter, or by telephone, the utility shall promptly make a suitable investigation and advise the complainant of the results thereof. If shall keep a record of all complaints which shall show the name and address of the complainant, the date and nature of the complaint, and the adjustment or disposition thereof for a period of one year subsequent to the final disposition of the complaint.

(C) Utility response. Upon receipt of a complaint, either by letter or by telephone, from the regulatory authority on behalf of a customer, the utility shall make a suitable investigation and advise the regulatory authority and complainant of the results thereof. An initial response must be made by the next working day. The utility must make a final and complete response within 15 days from the date of the complaint, unless additional time is granted within the 15-day period. The commission encourages all customer complaints to be made in writing to assist the regulatory authority in maintaining records of the quality of service of each utility; however, telephone communications will be acceptable.

(D) Deferred payment plan. The utility is encouraged to offer a deferred payment plan for delinquent residential accounts. If such a plan is offered, it shall conform to the following guidelines:

(i) Every deferred payment plan entered into due to the customer's inability to pay the outstanding bill in full must provide that service will not be discontinued if the customer pays current bills and a reasonable amount of the outstanding bill and agrees to pay the balance in reasonable installments until the bill is paid.

(ii) For purposes of determining reasonableness under these rules, the following shall be considered: size of delinquent account; customer's ability to pay; customer's payment history; time that the debt has been outstanding; reasons why

debt has been outstanding; and other relevant factors concerning the circumstances of the customer.

(iii) A deferred payment plan, if reduced to writing, offered by a utility shall state, immediately preceding the space provided for the customer's signature and in bold-face print at least two sizes larger than any other used, that: If you are not satisfied with this agreement, do not sign. If you are satisfied with this agreement, you give up your right to dispute the amount due under the agreement except for the utility's failure or refusal to comply with the terms of this agreement.

(iv) A deferred payment plan may include a one-time 5.0% penalty for late payment on the original amount of the outstanding bill with no prompt payment discount allowed except in cases where the outstanding bill is unusually high as a result of the utility's error (such as an inaccurately estimated bill or an incorrectly read meter). A deferred payment plan shall not include a finance charge.

(v) If a customer for utility service has not fulfilled terms of a deferred payment agreement or refuses to sign the same if it is reduced to writing, the utility shall have the right to disconnect pursuant to disconnection rules herein and, under such circumstances, it shall not be required to offer a subsequent negotiation of a deferred payment agreement prior to disconnection.

(vi) Any utility which institutes a deferred payment plan shall not refuse a customer participation in such a program on the basis of race, color, creed, sex, marital status, age, or any other form of discrimination prohibited by law.

(E) Delayed payment of bills by elderly persons.

(i) Applicability. This subparagraph applies only to:

(I) a utility that assesses late payment charges on residential customers and that suspends service before the 26th day after the date of the bill for which collection action is taken;

(II) utility bills issued on or after August 30, 1993; and

(III) an elderly person, as defined in clause (ii) of this subparagraph, who is a residential customer and who occupies the entire premises for which a delay is requested.

(ii) Definitions.

(I) Elderly person--A person who is 60 years of age or older.

(II) Utility - A gas utility or municipally owned utility, as defined in Texas Utilities Code, Sections 101.003(7), 101.003(8), and 121.001 - 121.006.

(iii) An elderly person may request that the utility implement the delay for either the most recent utility bill or for the most recent utility bill and each subsequent utility bill.

(iv) On request of an elderly person, a utility shall delay without penalty the payment date of a bill for providing utility services to that person until the 25th day after the date on which the bill is issued.

(v) The utility may require the requesting person to present reasonable proof that the person is 60 years of age or older.

(vi) Every utility shall notify its customers of this delayed payment option no less often than yearly. A utility may include this notice with other information provided pursuant to subparagraph (A) of this paragraph.

(3) Refusal of service.

(A) Compliance by applicant. Any utility may decline to serve an applicant for whom service is available from previously installed facilities until such applicant has complied with the state and municipal regulations and approved rules and regulations of the utility on file with the commission governing the service applied for or for the following reasons.

(i) Applicant's facilities inadequate. If the applicant's installation or equipment is known to be hazardous or of such character that satisfactory service cannot be given.

(ii) For indebtedness. If the applicant is indebted to any utility for the same kind of service as that applied for; provided, however, that in the event the indebtedness of the applicant for service is in dispute, the applicant shall be served upon complying with the applicable deposit requirement.

(iii) Refusal to make deposit. For refusal to make a deposit if applicant is required to make a deposit under these rules.

(B) Applicant's recourse. In the event that the utility shall refuse to serve an applicant under the provisions of these rules, the utility must inform the applicant of the basis of its refusal and that the applicant may file a complaint with the municipal regulatory authority or commission, whichever is appropriate.

(C) Insufficient grounds for refusal to serve. The following shall not constitute sufficient cause for refusal of service to a present customer or applicant:

(i) delinquency in payment for service by a previous occupant of the premises to be served;

(ii) failure to pay for merchandise or charges for nonutility service purchased from the utility;

(iii) failure to pay a bill to correct previous underbilling due to misapplication of rates more than six months prior to the date of application;

(iv) violation of the utility's rules pertaining to operation of nonstandard equipment or unauthorized attachments which interfere with the service of others unless the customer has first been notified and been afforded reasonable opportunity to comply with these rules;

(v) failure to pay a bill of another customer as guarantor thereof unless the guarantee was made in writing to the utility as a condition precedent to service; and

(vi) failure to pay the bill of another customer at the same address except where the change of customer identity is made to avoid or evade payment of a utility bill.

(4) Discontinuance of service.

(A) The due date of the bill for utility service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the regulatory authority. A bill for utility service is delinquent if unpaid by the due date.

(B) A utility may offer an inducement for prompt payment of bills by allowing a discount in the amount of 5.0% for payment of bills within 10 days after their issuance. This provision shall not apply where it conflicts with existing orders or ordinances of the appropriate regulatory authority.

(C) A customer's utility service may be disconnected if the bill has not been paid or a deferred payment plan pursuant to paragraph (2)(D) of this section has not been entered into within five working days after the bill has become delinquent and proper notice has been given. Proper notice consists of a deposit of the disconnect notice in the United States mail, postage prepaid or hand delivery of the disconnect notice to the customer at least five working days prior to the stated date of disconnection, with the words Termination Notice or similar language prominently displayed on the notice. Emailed disconnect notices may be provided in addition to deposit of the disconnect notice in the United States mail, postage prepaid or hand delivery to the customer. The notice shall be provided in English and Spanish as necessary to adequately inform the customer, and shall include the date of termination, the hours, address, and telephone number where payment may be made, and a statement that if a health or other emergency exists, the utility may be contacted concerning the nature of the emergency and the relief available, if any, to meet such emergency.

(D) Utility service may be disconnected for any of the following reasons:

(i) failure to pay a delinquent account or failure to comply with the terms of a deferred payment plan for installment payment of a delinquent account;

(ii) violation of the utility's rules pertaining to the use of service in a manner which interferes with the service of others or the operation of nonstandard equipment, if a reasonable attempt has been made to notify the customer and the customer is provided with a reasonable opportunity to remedy the situation;

(iii) failure to comply with deposit or guarantee arrangements where required by paragraph (5) of this section;

(iv) without notice where a known dangerous condition exists for as long as the condition exists;

(v) tampering with the utility company's meter or equipment or bypassing the same.

(E) Utility service may not be disconnected for any of the following reasons:

(i) delinquency in payment for service by a previous occupant of the premises;

(ii) failure to pay for merchandise or charges for nonutility service by the utility;

(iii) failure to pay for a different type or class of utility service unless fee for such service is included on the same bill;

(iv) failure to pay the account of another customer as guarantor thereof, unless the utility has in writing the guarantee as a condition precedent to service;

(v) failure to pay charges arising from an underbilling occurring due to any misapplication of rates more than six months prior to the current billings;

(vi) failure to pay charges arising from an underbilling due to any faulty metering, unless the meter has been tampered with or unless such underbilling charges are due;

(vii) failure to pay an estimated bill other than a bill rendered pursuant to an approved meter reading plan, unless the utility is unable to read the meter due to circumstances beyond its control.

(F) Unless a dangerous condition exists, or unless the customer requests disconnection, service shall not be disconnected on a day, or on a day immediately preceding a day, when personnel of the utility are not available to the public for the purpose of making collections and reconnecting service.

(G) No utility may abandon a customer without written approval from the regulatory authority.

(H) No utility may discontinue service to a delinquent residential customer permanently residing in an individually metered dwelling unit when that customer establishes that discontinuance of service will result in some person residing at that residence becoming seriously ill or more seriously ill if the service is discontinued. Any customer seeking to avoid termination of service under this section must make a written request supported by a written statement from a licensed physician. Both the request and the statement must be received by the utility not more than five working days after the date of delinquency of the bill. The prohibition against service termination provided by this section shall last 20 days from the date of receipt by the utility of the request and statement or such lesser period as may be agreed upon by the utility and the customer. The customer who makes such request shall sign an installment agreement which provides for payment of such service along with timely payments for subsequent monthly billings.

(5) Applicant deposit.

(A) Establishment of credit for residential applicants. Each utility may require a residential applicant for service to satisfactorily establish credit but such establishment of credit shall not relieve the customer from complying with rules for prompt payment of bills. Subject to these rules, a residential applicant shall not be required to pay a deposit:

(i) if the residential applicant has been a customer of any utility for the same kind of service within the last two years and is not delinquent in payment of any such utility service account and during the last 12 consecutive months of service did not have more than one occasion in which a bill for such utility service was paid after becoming delinquent and never had service disconnected for nonpayment;

(ii) if the residential applicant furnishes in writing a satisfactory guarantee to secure payment of bills for the service required; or

(iii) if the residential applicant furnishes in writing a satisfactory credit rating by appropriate means, including, but not limited to, the production of generally acceptable credit cards, letters of credit reference, the names of credit references which may be quickly and inexpensively contacted by the utility, or ownership of substantial equity.

(B) Reestablishment of credit. Every applicant who has previously been a customer of the utility and whose service has been discontinued for nonpayment of bills shall be required before service is rendered to pay all his amounts due the utility or execute a written deferred payment agreement, if offered, and reestablish credit as provided in subparagraph (A) of this paragraph.

(C) Amount of deposit and interest for residential service, and exemption from deposit.

(i) Each gas utility shall waive any deposit requirement for residential service for an applicant who has been determined to be a victim of family violence as defined in Texas Family Code, 71.004, by a family violence center, by treating medical personnel, by law enforcement agency personnel, or by a designee of the Attorney General in the Crime Victim Services Division of the Office of the Attorney General. This determination shall be evidenced by the applicant's submission of a certification letter developed by the Texas Council on Family Violence and made available on its web site.

(ii) The required deposit shall not exceed an amount equivalent to one-sixth of the estimated annual billings. If actual use is at least twice the amount of the estimated billings, a new deposit requirement may be calculated and an additional deposit may be required within two days. If such additional deposit is not made, the utility may disconnect service under the standard disconnection procedure for failure to comply with deposit requirements.

(iii) All applicants for residential service who are 65 years of age or older will be considered as having established credit if such applicant does not have an outstanding account balance with the utility or another utility for the same utility service which accrued within the last two years. No cash deposit shall be required of such applicant under these conditions.

(iv) Each utility which requires deposits to be made by its customers shall pay a minimum interest on such deposits according to the rate as established by law. If refund of deposit is made within 30 days of receipt of deposit, no interest payment

is required. If the utility retains the deposit more than 30 days, payment of interest shall be made retroactive to the date of deposit.

(I) Payment of interest to the customer shall be annually or at the time the deposit is returned or credited to the customer's account.

(II) The deposit shall cease to draw interest on the date it is returned or credited to the customer's account.

(D) Deposits for temporary or seasonal service and for weekend or seasonal residences. The utility may require a deposit sufficient to reasonably protect it against the assumed risk, provided such a policy is applied in a uniform and nondiscriminatory manner.

(E) Records of deposits.

(i) The utility shall keep records to show:

(I) the name and address of each depositor;

(II) the amount and date of the deposit; and

(III) each transaction concerning the deposit.

(ii) The utility shall issue a receipt of deposit to each applicant from whom a deposit is received and shall provide means whereby a depositor may establish claim if the receipt is lost.

(iii) A record of each unclaimed deposit must be maintained for at least four years, during which time the utility shall make a reasonable effort to return the deposit.

(F) Refund of deposit.

(i) If service is not connected or after disconnection of service, the utility shall promptly and automatically refund the customer's deposit plus accrued interest on the balance, if any, in excess of the unpaid bills for service furnished. The transfer of service from one premise to another within the service area of the utility shall not be deemed a disconnection within the meaning of these rules, and no additional deposit may be demanded unless permitted by these rules.

(ii) When the customer has paid bills for service for 12 consecutive residential bills without having service disconnected for nonpayment of bill and without having more than two occasions in which a bill was delinquent and when the customer is not delinquent in the payment of the current bills, the utility shall promptly and automatically refund the deposit plus accrued interest to the customer in the form of cash or credit to a customer's account.

(G) Upon sale or transfer of utility or company. Upon the sale or transfer of any public utility or operating units thereof, the seller shall file with the commission under oath, in addition to other information, a list showing the names and addresses of all customers served by such utility or unit who have to their credit a deposit, the date such deposit was made, the amount thereof, and the unpaid interest thereon.

(H) Complaint by applicant or customer. Each utility shall direct its personnel engaged in initial contact with an applicant or customer for service seeking to establish or reestablish credit under the provisions of these rules to inform the customer, if dissatisfaction is expressed with the utility's decision, of the customer's right to file a complaint with the regulatory authority thereon.

(6) Billing.

(A) Bills for gas service shall be rendered monthly, unless otherwise authorized or unless service is rendered for a period less than a month. Bills shall be rendered as promptly as possible following the reading of meters.

(B) The customer's bill must show all the following information whether it is issued through the United States mail or electronic methods. The information must be arranged and displayed in such a manner as to allow the customer to compute his bill with the applicable rate schedule. The applicable rate schedule must be mailed to the customer on request of the customer. A utility may exhaust its present stock of nonconforming bill forms before compliance is required by this section:

(i) if the meter is read by the utility, the date and reading of the meter at the beginning and end of the period for which rendered;

(ii) the number and kind of units billed;

(iii) the applicable rate schedule title or code;

(iv) the total base bill;

(v) the total of any adjustments to the base bill and the amount of adjustments per billing unit;

(vi) the date by which the customer must pay the bill to get prompt payment discount;

(vii) the total amount due before and after any discount for prompt payment within a designated period;

(viii) a distinct marking to identify an estimated bill.

(C) Where there is good reason for doing so, estimated bills may be submitted, provided that an actual meter reading is taken at least every six months. For the second consecutive month in which the meter reader is unable to gain access to the premises to read the meter on regular meter reading trips, or in months where meters are not read otherwise, the utility must provide the customer with a postcard and request that the customer read the meter and return the card to the utility if the meter is of a type that can be read by the customer without significant inconvenience or special tools or equipment. If such a postcard is not received by the utility in time for billing, the utility may estimate the meter reading and render the bill accordingly.

(D) Disputed bills.

(i) In the event of a dispute between the customer and the utility regarding the bill, the utility must forthwith make such investigation as is required by the particular case and report the results thereof to the customer. If the customer wishes to obtain the benefits of clause (ii) of this subparagraph, notification of the dispute must be given to the utility prior to the date the bill becomes delinquent. In the event the dispute is not resolved, the utility shall inform the customer of the complaint procedures of the appropriate regulatory authority.

(ii) Notwithstanding any other subsection of this section, the customer shall not be required to pay the disputed portion of the bill which exceeds the amount of that customer's average usage for the billing period at current rates until the earlier of the following: resolution of the dispute or the expiration of the 60-day period beginning on the day the disputed bill is issued. For purposes of this section only, the customer's average usage for the billing period shall be the average of the customer's usage for the same billing period during the preceding two years. Where no previous usage history exists, the average usage shall be estimated on the basis of usage levels of similar customers and under similar conditions.

(7) Meters.

(A) Meter requirements.

(i) Use of meter. All gas sold by a utility must be charged for by meter measurements, except where otherwise provided for by applicable law, regulation of the regulatory authority, or tariff.

(ii) Installation by utility. Unless otherwise authorized by the regulatory authority, each utility must provide and install and will continue to own and maintain all meters necessary for measurement of gas delivered to its customers.

(iii) Standard type. No utility may furnish, set up, or put in use any meter which is not reliable and of a standard type which meets generally accepted industry standards; provided, however, special meters not necessarily conforming to such standard types may be used for investigation, testing, or experimental purposes.

(B) Meter records. Each utility must keep the following records:

(i) Meter equipment records. Each utility must keep a record of all its meters, showing the customer's address and date of the last test.

(ii) Records of meter tests. All meter tests must be properly referenced to the meter record provided for therein. The record of each test made on request of a customer must show the identifying number and constants of the meter, the standard meter and other measuring devices used, the date and kind of test made, by whom made,

the error (or percentage of accuracy) at each load tested, and sufficient data to permit verification of all calculations.

(iii) Meter readings--meter unit location. In general, each meter must indicate clearly the units of service for which charge is made to the customer.

(iv) Meter tests on request of customer.

(I) Each utility must, upon request of a customer, make a test of the accuracy of the meter serving that customer. The utility must inform the customer of the time and place of the test and permit the customer or his authorized representative to be present if the customer so desires. If no such test has been performed within the previous four years for the same customer at the same location, the test is to be performed without charge. If such a test has been performed for the same customer at the same location within the previous four years, the utility is entitled to charge a fee for the test not to exceed $15 or such other fee for the testing of meters as may be set forth in the utility's tariff properly on file with the regulatory authority. The customer must be properly informed of the result of any test on a meter that serves him.

(II) Notwithstanding subclause (I) of this clause, if the meter is found to be more than nominally defective, to either the customer's or the utility's disadvantage, any fee charged for a meter test must be refunded to the customer. More than nominally defective means a deviation of more than 2.0% from accurate registration.

(v) Bill adjustments due to meter error.

(I) If any meter test reveals a meter to be more than nominally defective, the utility must correct previous readings consistent with the inaccuracy found in the meter for the period of either:

(-a-) the last six months; or

(-b-) the last test of the meter, whichever is shorter. Any resulting underbillings or overbillings are to be corrected in subsequent bills, unless service is terminated, in which event a monetary adjustment is to be made. This requirement for a correction may be foregone by the utility if the error is to the utility's disadvantage.

(II) If a meter is found not to register for any period of time, the utility may make a charge for units used but not metered for a period not to exceed three months previous to the time the meter is found not to be registering. The determination of amounts used but not metered is to be based on consumption during other like periods by the same customer at the same location, when available, and on consumption under similar conditions at the same location or of other similarly situated customers, when not available.

(8) New construction.

(A) Standards of construction. Each utility is to construct, install, operate, and maintain its plant, structures, equipment, and lines in accordance with the provisions of such codes and standards as are generally accepted by the industry, as modified by rule or regulation of the regulatory authority or otherwise by law, and in such manner to best accommodate the public and to prevent interference with service furnished by other public utilities insofar as practical.

(B) Line extension and construction charges. Every utility must file its extension policy. The policy must be consistent, nondiscriminatory, and is subject to the approval of the regulatory authority. No contribution in aid of construction may be required of any customer except as provided for in extension policy.

(C) Response to request for service. Every gas utility must serve each qualified applicant for service within its service area as rapidly as practical. As a general policy, those applications not involving line extensions or new facilities should be filled within seven working days. Those applications for individual residential service requiring line extensions should be filled within 90 days unless unavailability of materials or other causes beyond the control of the utility result in

unavoidable delays. In the event that residential service is delayed in excess of 90 days after an applicant has met credit requirements and made satisfactory arrangements for payment of any required construction charges, a report must be made to the regulatory authority listing the name of the applicant, location, and cause for delay. Unless such delays are due to causes which are reasonably beyond the control of the utility, a delay in excess of 90 days may be found to constitute a refusal to serve.

OS-20-00004865

Final Order

Attachment 2

(Depreciation Rates and Net Plant in Service)

Universal Natual Gas, LLC Statement of Intent
OS-20-00004865 Consolidated UniGas
Settlement Exhibit C - Net Plant and Depreciation Rate by Account

Line No.	Description	FERC Account	Plant Balance	Accumulated Depreciation	Net Plant	Depreciation Rate
	(a)	(b)	(c)	(d)	(e)	(f)
1	**Consolidated UniGas**					
2	Organization	301.00	$ -	$ -	$ -	
3	Franchises and Consents	302.00	76,315	23,327	52,988	1.08%
4	Misc. Intangible Plant	303.00	205,311	90,426	114,885	2.90%
5	**Subtotal: Intangible Plant**		**281,626**	**113,753**	**167,873**	
6	Land and Land Rights	374.00	754,711	41,576	713,136	2.90%
7	Mains	376.00	17,782,759	2,980,268	14,802,491	2.23%
8	Measure & Reg. Station - General	378.00	1,662,341	438,370	1,223,971	2.48%
9	Services	380.00	2,388,313	809,243	1,579,070	2.36%
10	Meters	381.00	4,350,716	1,267,979	3,082,737	3.31%
11	Meters - AMR	381.00				6.60%
12	House Regulators	383.00	774,948	237,299	537,649	2.72%
13	**Subtotal: Distribution Plant**		**27,713,789**	**5,774,735**	**21,939,054**	
14	Land and Land Rights	389.00	-	-	-	
15	Structures and Improvements	390.00	165,839	70,503	95,336	14.29%
16	Office Furniture & Equipment	391.00	648,828	309,293	339,535	5.00%
17	Computer Equipment	391.10				33.33%
18	Transportation Equipment	392.00	572,231	243,272	328,959	14.29%
19	Tools, Shop and Garage	394.00	147,977	62,909	85,068	14.29%
20	Power Operated Equipment	396.00	49,859	49,859	-	12.50%
21	Communication Equipment	397.00	-	-	-	6.67%
22	Misc. Equip	398.00	153,502	153,502	-	4.00%
23	**Subtotal: General Plant**		**1,738,236**	**889,338**	**848,898**	
24	**Total Consolidated UniGas**		**29,733,651**	**6,777,826**	**22,955,825**	

CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS.

Subchapter J. COSTS, RATES AND TARIFFS.

DIVISION 1: RETAIL RATES.

§25.243. Distribution Cost Recovery Factor (DCRF).

(a) **Purpose and application.** This section implements Public Utility Regulatory Act (PURA) §36.210. This section applies to electric utilities, including transmission and distribution utilities (TDUs), that provide wholesale or retail distribution service.

(b) **Definitions.** The following terms, when used in this section, have the following meanings unless the context indicates otherwise.

(1) **Capitalized operations and maintenance expenses** -- Expenses that have been deferred or amortized as a regulatory asset or liability.

(2) **DCRF proceeding** -- A proceeding conducted pursuant to this section in which creation or amendment of a DCRF is considered on application of an electric utility to the commission pursuant to subsection (c)(1) of this section.

(3) **Distribution invested capital** -- The parts of the electric utility's invested capital, as described in PURA §36.053, that are categorized as distribution plant, distribution-related intangible plant, and distribution-related communication equipment and networks properly recorded in Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 303, 352, 353, 360 through 374, 391, and 397. Distribution invested capital includes only costs: for plant that has been placed into service; that comply with PURA, including §36.053 and §36.058; and that are prudent, reasonable, and necessary. Distribution invested capital does not include: generation-related costs; transmission-related costs, including costs recovered through rates set pursuant to §25.192 of this title (relating to Transmission Service Rates), §25.193 of this title (relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF)), or §25.239 of this title (relating to Transmission Cost Recovery Factor for Certain Electric Utilities); indirect corporate costs; capitalized operations and maintenance expenses; and distribution invested capital recovered through a separate rate, including a surcharge, tracker, rider, or other mechanism. In a DCRF proceeding, an electric utility may elect not to seek recovery of certain distribution invested capital, but may not exclude all of the distribution invested capital in one of the accounts identified above unless the electric utility can prove that the distribution invested capital in the account reduced by the related accumulated depreciation is greater than the distribution invested capital in the account reduced by the related accumulated depreciation used in setting rates in the electric utility's last comprehensive base-rate proceeding.

(4) **Net distribution invested capital** -- Distribution invested capital less accumulated depreciation and adjusted for any changes in distribution-related accumulated deferred federal income taxes and excluding any impact associated with Financial Accounting Standards Board Interpretation No. 48 (FIN 48).

(5) **Weather-normalized** -- Adjusted for normal weather using weather data for the most recent ten calendar years.

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(c) **Application for a DCRF.**

(1) **General requirements.**

(A) **Filing of application.** An electric utility may apply for inclusion of a DCRF in its tariffs for wholesale and retail distribution service. To implement a DCRF, an electric utility shall file the application for the DCRF simultaneously with all regulatory authorities having original jurisdiction over the electric utility's distribution service area.

(B) **Municipal proceedings.** A municipality's governing body with original jurisdiction over an application for a DCRF shall make a final decision on the application within 60 days after the application was filed. If the governing body does not make a final decision within 60 days after the application was filed, the application is deemed denied by the governing body. On the 60th day after the application is filed, the electric utility is deemed to appeal the governing body's final decision to the commission, regardless of whether the governing body approves or denies the application, and the appeal is deemed at that time to be consolidated with the electric utility's DCRF proceeding before the commission. In addition, the governing body's interim and final decisions are deemed automatically suspended at the times they took effect.

(C) **Frequency of DCRF proceedings.** An electric utility may have no more than one DCRF (including a DCRF amendment) become effective each calendar year pursuant to an application filed pursuant to this paragraph. An electric utility may change its rates pursuant to a DCRF no more than four times between comprehensive base-rate proceedings. An electric utility shall not apply for a DCRF while a comprehensive base-rate proceeding for the electric utility is pending. In addition, the presiding officer shall dismiss an electric utility's application for a DCRF if the electric utility or commission initiates a comprehensive base-rate proceeding within 145 days after the electric utility filed the application for a DCRF.

(2) **Requirements applicable to TDUs.** A TDU may file an application for a DCRF only during the period April 1 through April 8. A TDU shall not file an application for a DCRF after April 8 of a year even if April 8 is not a working day, as defined by §22.2(44) of this title (relating to Definitions).

(3) **Requirements applicable to other electric utilities.** An electric utility that does not offer customer choice may file an application for a DCRF at any time other than in April and May.

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(d) **Calculation of DCRF.**

(1) **DCRF formula.** The DCRF for each rate class shall be calculated using the following formula:

$$[((DIC_C - DIC_{RC}) * ROR_{AT}) + (DEPR_C - DEPR_{RC}) + (FIT_C - FIT_{RC}) + (OT_C - OT_{RC}) - \sum(DISTREV_{RC\text{-}CLASS} * \%GROWTH_{CLASS})] * ALLOC_{CLASS} / BD_{C\text{-}CLASS}$$

Where:

DIC_C = Current Net Distribution Invested Capital.

DIC_{RC} = Net Distribution Invested Capital from the last comprehensive base-rate proceeding.

ROR_{AT} = After-Tax Rate of Return as defined in paragraph (2) of this subsection.

$DEPR_C$ = Current Depreciation Expense, as related to Current Gross Distribution Invested Capital, calculated using the currently approved depreciation rates.

$DEPR_{RC}$ = Depreciation Expense, as related to Gross Distribution Invested Capital, from the last comprehensive base-rate proceeding.

FIT_C = Current Federal Income Tax, as related to Current Net Distribution Invested Capital, including the change in federal income taxes related to the change in return on rate base and synchronization of interest associated with the change in rate base resulting from additions to and retirements of distribution plant as used to compute Net Distribution Invested Capital.

FIT_{RC} = Federal Income Tax, as related to Net Distribution Invested Capital from the last comprehensive base-rate proceeding.

OT_C = Current Other Taxes (taxes other than income taxes and taxes associated with the return on rate base), as related to Current Net Distribution Invested Capital, calculated using current tax rates and the methodology from the last comprehensive base-rate proceeding, and not including municipal franchise fees.

OT_{RC} = Other Taxes, as related to Net Distribution Invested Capital from the last comprehensive base-rate proceeding, and not including municipal franchise fees.

$DISTREV_{RC\text{-}CLASS}$ (Distribution Revenues by rate class based on Net Distribution Invested Capital from the last comprehensive base-rate proceeding) = $(DIC_{RC\text{-}CLASS} * ROR_{AT}) + DEPR_{RC\text{-}CLASS} + FIT_{RC\text{-}CLASS} + OT_{RC\text{-}CLASS}$.

$\%GROWTH_{CLASS}$ (Growth in Billing Determinants by Class) = $(BD_{C\text{-}CLASS} - BD_{RC\text{-}CLASS}) / BD_{RC\text{-}CLASS}$

$DIC_{RC\text{-}CLASS}$ = Net Distribution Invested Capital allocated to the rate class from the last comprehensive base-rate proceeding.

$DEPR_{RC\text{-}CLASS}$ = Depreciation Expense, as related to Gross Distribution Invested Capital, allocated to the rate class in the last comprehensive base-rate proceeding.

$FIT_{RC\text{-}CLASS}$ = Federal Income Tax, as related to Net Distribution Invested Capital, allocated to the rate class in the last comprehensive base-rate proceeding.

$OT_{RC\text{-}CLASS}$ = Other Taxes, as related to Net Distribution Invested Capital, allocated to the rate class in the last comprehensive base-rate proceeding, and not including municipal franchise fees.

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$ALLOC_{CLASS}$ = Rate Class Allocation Factor approved in the last comprehensive base-rate proceeding, calculated as: total net distribution plant allocated to rate class, divided by total net distribution plant. For situations in which data from the last comprehensive base-rate proceeding are not available to perform the described calculation, the Rate Class Allocation Factor shall be calculated as the total distribution revenue requirement allocated to the rate class (less any identifiable amounts explicitly unrelated to Distribution Invested Capital) divided by the total distribution revenue requirement (less any identifiable amounts explicitly unrelated to Distribution Invested Capital) for all classes as approved by the commission in the electric utility's last comprehensive base-rate case.

$BD_{C\text{-}CLASS}$ = Rate Class Billing Determinants (weather-normalized and adjusted to reflect the number of customers at the end of the period) for the 12 months ending on the date used for purposes of determining the Current Net Distribution Invested Capital. For customer classes billed primarily on the basis of kilowatt-hour billing determinants, the DCRF shall be calculated using kilowatt-hour billing determinants. For customer classes billed primarily on the basis of demand billing determinants, the DCRF shall be calculated using demand billing determinants.

$BD_{RC\text{-}CLASS}$ = Rate Class Billing Determinants used to set rates in the last comprehensive base-rate proceeding.

If an input to the DCRF formula from the last comprehensive base-rate proceeding is not separately identified in that proceeding, it shall be derived from information from that proceeding.

(2) **Return on invested capital.** The electric utility's rate of return is the rate of return approved by the commission in the electric utility's last comprehensive base-rate proceeding if the final order (which may be an order on rehearing) approving the rate of return was filed less than three years before the application for a DCRF was filed. If the final order approving the rate of return was filed three years or more before the application for a DCRF was filed, the rate of return is the lesser of the rate of return in the final order or the alternative rate of return calculated as follows: The alternative rate of return shall be calculated using a 10% cost of equity, the capital structure approved by the commission in the electric utility's last comprehensive base-rate proceeding, and the cost of debt as reported in the electric utility's most recent Earnings Monitoring Report filed pursuant to §25.73 of this title (relating to Financial and Operating Reports).

(3) **Determination of Distribution Invested Capital.** The electric utility must clearly identify any costs included as distribution invested capital because of a change in accounting rules or practices since the test year in the electric utility's most recent comprehensive base-rate proceeding. The commission shall exclude such costs if the electric utility does not prove that the costs are appropriate for recovery through the DCRF.

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(e) **Procedures for DCRF proceeding.**

(1) **Filing requirements.** To file an application for a DCRF, an electric utility shall use the commission-prescribed form and include a sworn statement from an appropriate employee of the electric utility that the application complies with the electric utility's tariff and this section, including that the distribution invested capital in the application includes only costs: for plant that has been placed into service; that comply with PURA, including §36.053 and §36.058; and that are prudent, reasonable, and necessary. In addition, the sworn statement shall state that the application is true and correct to the best of the employee's knowledge, information, and belief. Furthermore, the electric utility shall include in its application an earnings monitoring report for the immediately preceding calendar year prepared in accordance with §25.73(b) of this title.

(2) **Notice and intervention deadline.** By the day after it files its application, the electric utility shall provide notice of its application, using a reasonable method of notice, to all parties in the electric utility's last comprehensive base-rate proceeding and, if applicable, last DCRF proceeding, and shall include in the notice the docket number for the new proceeding. The intervention deadline is 30 days from the date service of notice is completed.

(3) **Parties.** The Office of Public Utility Counsel and affected parties may participate as parties in a DCRF proceeding.

(4) **Denial due to earnings.** The commission shall deny an electric utility's application for a DCRF if the earnings monitoring report included in the electric utility's application shows that the electric utility is earning more than its authorized rate of return using weather-normalized data. In making this determination, the commission shall correct the calculation of the earned rate of return in the earnings monitoring report to the extent that the calculation does not comply with §25.73(b) of this title and any form adopted to implement that subsection.

(5) **Scope of proceeding.** The issues of whether distribution invested capital included in an application for a DCRF or DCRF adjustment complies with PURA, including §36.053 and §36.058, and is prudent, reasonable, and necessary shall not be addressed in a DCRF proceeding unless the presiding officer finds that good cause exists to address these issues.

(6) **Commission processing of application.**

(A) **Sufficiency of application.** A motion to find an application materially deficient shall be filed no later than 30 days after service of notice is completed. The motion shall be served on the electric utility by hand delivery, facsimile transmission, or overnight courier delivery, or by e-mail if agreed to by the electric utility or ordered by the presiding officer. The motion shall specify the nature of the deficiency and the relevant portions of the application, and cite the particular requirement with which the application is alleged not to comply. The electric utility's response to a motion to find an application materially deficient shall be filed no later than five working days after such motion is received. If within ten working days after the deadline for filing a motion to find an application materially deficient, the presiding officer has not issued a written order concluding that material deficiencies exist in the application, the application is deemed sufficient.

(B) Discovery. Each party, other than commission staff, may serve no more than 20 requests for information and requests for admissions of fact pursuant to §22.144 of this title (relating to Requests for Information and Requests for Admission of Facts), except where the presiding officer finds good cause for a party to serve additional requests. Except for a request by commission staff, a request shall not include subparts or multiple questions, and requests shall be sequentially numbered,

regardless of whether the requests are served at the same time or on different parties. A response to a request shall be served no later than ten working days after receipt of the discovery request. An objection to a request shall be filed no later than five working days from receipt of the request. A request for which an objection is filed does not count towards a party's request limit. A party may request a technical conference by the intervention deadline, and shall identify the topics that it wants to discuss. An electric utility shall hold the technical conference in Austin, Texas five working days after the intervention deadline, unless the electric utility and the parties who requested the technical conference agree to a different date. The technical conference shall be held at the location designated by the electric utility, unless the commission staff designates a location. The electric utility shall have appropriate persons attend the technical conference to answer questions. A party may take a deposition only if authorized by the presiding officer.

(C) System-wide rates and effective date of DCRF. The presiding officer shall approve the DCRF for an electric utility on a system-wide basis and set the effective date of the DCRF for a TDU as September 1 unless good cause exists for a later date. The presiding officer shall make a final decision on a DCRF application made by a TDU at least 46 days before the effective date of the approved rates, even if this requirement results in an effective date after September 1. For an electric utility that does not offer customer choice, the presiding officer shall set the effective date of the DCRF to be 145 days after the application was filed unless good cause exists for a later date.

(D) Review of application. A DCRF proceeding is eligible for disposition pursuant to §22.35(b)(1) of this title (relating to Informal Disposition).

(E) Notice of approved rates. Unless otherwise ordered, a TDU shall serve notice of the approved rates and the effective date of the approved rates by the working day after the presiding officer's final decision, to retail electric providers that are authorized by the registration agent to provide service in the TDU's distribution service area. Notice under this subparagraph of this paragraph may be served by email.

(f) **DCRF reconciliation.** The commission shall reconcile investments recovered through a DCRF in the electric utility's next comprehensive base-rate proceeding to the extent such reconciliation did not already occur in a DCRF proceeding pursuant to subsection (e)(5) of this section. The reconciliation shall be limited to the issues of the extent to which the investments complied with PURA, including §36.053 and §36.058, and this section and were prudent, reasonable, and necessary. To the extent that the commission determines that the investments did not comply with PURA and this section or were not prudent, reasonable, and necessary, the electric utility shall refund all revenues related to the investments that it improperly recovered through rates, and shall also pay its customers carrying charges on these revenues. The carrying charges shall be determined as follows: For the time period beginning with the date on which over-recovery is determined to have begun to the effective date of the new base rates, carrying costs shall be calculated using the same rate of return that was applied to the investments in the DCRF proceedings that resulted in the over-recovery. For the time period beginning with the effective date of the new base rates, carrying costs shall be calculated using the electric utility's rate of return authorized in the comprehensive base-rate proceeding.

(g) **DCRF's effect on electric utility's financial risk and rate of return.** In setting the rate of return for an electric utility with a DCRF, the commission may expressly consider the effect of the DCRF on the electric utility's financial risk and rate of return.

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(h) **Reports.** An electric utility with a DCRF shall file reports that will permit the commission to monitor its DCRF revenues, in accordance with any filing requirements and schedules prescribed by the commission pursuant to §25.73 of this title or this section.

(i) **Expiration.** This section expires upon the expiration of PURA §36.210. Any DCRF in effect at that time shall remain in effect until the electric utility's next comprehensive base-rate proceeding.

Control Number: 51415

Item Number: 705

PUC DOCKET NO. 51415
SOAH DOCKET NO. 473-21-0538

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the application of Southwestern Electric Power Company (SWEPCO) for authority to change its rates. Through its application and rebuttal testimony, SWEPCO sought a Texas retail revenue requirement of $451,529,538.

A hearing on the merits was held between May 19 and May 26, 2021 at the State Office of Administrative Hearings (SOAH). On August 27, 2021, the SOAH administrative law judges (ALJs) filed their proposal for decision in which they recommended a Texas retail revenue requirement decrease to SWEPCO's Texas retail revenue requirement of $26,495,690. In response to the parties' exceptions and replies to the proposal for decision, on November 9, 2021, the SOAH ALJs filed a letter making changes to the proposal for decision.

The Commission adopts the proposal for decision as modified by the ALJs, including findings of fact and conclusions of law, to the extent provided in this Order.

I. Discussion

The Commission's decisions result in a Texas retail base-rate revenue requirement of $400,742,913, which is a decrease of $50,786,625 from SWEPCO's requested Commission-authorized revenue requirement. New findings of fact 24A-I and 315A-C are added to address the procedural history of this docket after the close of the evidentiary record at SOAH. Additionally, the Commission modifies finding of fact 286 to reflect the rate schedules produced by Commission Staff's updated number run.

A. Self-Insurance Reserve and Hurricane Laura Costs

The Commission disagrees with the SOAH ALJs' finding that SWEPCO failed to sufficiently quantify the amount of savings of the self-insurance in comparison to commercial insurance to support establishment of a self-insurance reserve. In this proceeding SWEPCO presented adequate testimony on cost savings attributable to the self-insurance plan. While

SWEPCO did not quantify the precise savings associated with its self-insurance proposal, it did offer a detailed assessment of the expenses SWEPCO would avoid through the plan. Therefore, the Commission rejects the proposal for decision and approves the self-insurance reserve plan proposed by SWEPCO.

SWEPCO also requested authorization to charge its Texas jurisdictional Hurricane Laura restoration costs against the self-insurance reserve discussed above. Because the Commission approves SWEPCO's proposed self-insurance reserve plan it also approves the charging of Hurricane Laura restoration costs against the self-insurance reserve. To reflect these determinations, the Commission modifies findings of fact 96 and adds new finding of fact 96A. The Commission also modifies conclusion of law 30.

B. Return on Equity

The SOAH ALJs recommended a return on equity of 9.45%. After consideration of the evidence and expert witness testimony the Commission finds that a return on equity of 9.25% is appropriate. Market conditions indicate electric utilities continue to enjoy favorable access to capital financing in the form of short- and long-term interest rates, while electric utility returns on equity have continued to decrease since SWEPCO's last rate case in 2017. Furthermore, in establishing a reasonable return on invested capital, PURA[1] § 36.052 provides the Commission authority to consider the efforts of the utility in conserving resources; the quality of service; the efficiency of operations; and the quality of management. SWEPCO has continued to increase its vegetation management expenses but its system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) scores have worsened since 2018 which is indicative of periodically unreliable service quality and substandard operational planning. Therefore, the Commission deletes finding of fact 101 and modifies findings of fact 97, 98, 100, and 105.

C. Vegetation Management

Due to SWEPCO's service quality record and vegetation management deficiencies, Commission Staff recommended that SWEPCO be required to hire a consultant to conduct a review of the transmission system and make recommendations to improve performance. While

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

the SOAH ALJs did not recommend the hiring of an independent consultant, they did remark that SWEPCO's worsening SAIFI and SAIDI scores are troubling. The Commission finds that SWEPCO should be required to include additional information as part of its annual reports filed under 16 Texas Administrative Code (TAC) § 25.97(f). The additional information should include each occurrence of an outage related to vegetation contact with utility infrastructure and, for each line identified, the length of time since that line last received vegetation management treatment. Finally, the information should identify every distribution line that has not received vegetation management treatment in the previous four years. Therefore, the Commission deletes finding of fact 123 and adds finding of fact 123A.

D. Financial Integrity and Ring-Fencing

SWEPCO is just one of many American Electric Power Company, Inc. (AEP) subsidiaries. AEP and its various subsidiaries engage in a range of activities related to electricity production, delivery, and service across the country. Commission Staff recommended imposing 15 ring-fencing provisions for SWEPCO as part of this proceeding. Recognizing that the financial instability of an affiliate entity could impact SWEPCO, the SOAH ALJs ultimately recommended that 11 of the provisions be adopted in consideration of the demonstrated value of ring-fencing protections. After reviewing the record and parties' briefs, the Commission finds that two additional provisions should be implemented to insulate customers' rates from any financial instabilities of its parent company, AEP, and AEP's other subsidiaries. The Commission requires the additional ring-fencing provisions, of a no cross-default provision and a no financial covenants or rating agency triggers related to another entity provision. Accordingly, the Commission adds new finding of fact 109A.

E. Allocated Transmission Expenses Related to Behind-the-Meter Generation

The SOAH ALJs recommended removal of 146 megawatts (MW) of Eastman's behind-the-meter generation (BTMG) load that SWEPCO added to its Texas jurisdiction for allocation purposes. The Commission ultimately agrees with the SOAH ALJs' conclusion however it determined that specific discussion on federal jurisdiction and the filed-rate doctrine were unnecessary. Therefore, the Commission modifies the proposal for decision to remove findings of fact 209 through 212, as well as conclusions of law 34 through 37, because those findings and conclusions are unnecessary to support this Order.

F. Texas Cotton Gin Association Class Allocation

The SOAH ALJs recommended that the Texas Cotton Gin Association did not present an alternative class allocation or rate deign proposal, and therefore did not make any rate adjustment in response to the Texas Cotton Gin Association's assertions. As Commission Staff correctly notes, the allocation of costs based on system wide rates is consistent with prior Commission precedent. Therefore, the Commission deletes finding of fact 251 from the proposal for decision as unnecessary to support this Order.

G. Minor or Non-Substantive Changes

In addition to the changes described above, the Commission makes several minor modifications or corrections to the proposed findings of fact and conclusions of law.

Finally, the Commission makes non-substantive changes to findings of fact and conclusions of law for such matters as capitalization, spelling, punctuation, style, grammar, readability, and conformity with the Commission's order writing format.

II. Findings of Fact

The Commission adopts the following findings of fact.

Applicant

1. SWEPCO is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP) and is a fully integrated electric utility serving retail and wholesale customers in Texas, Louisiana, and Arkansas.

2. SWEPCO serves approximately 187,400 Texas retail customers, all of whom are affected by SWEPCO's application to change rates.

3. The Federal Energy Regulatory Commission (FERC) regulates SWEPCO's wholesale electric operations.

4. On October 14, 2020, SWEPCO filed its petition and statement of intent requesting that the Commission authorize SWEPCO to increase its Texas retail base rate revenue by $90,199,736, which is an increase of 26.03% over its adjusted Texas retail test-year base-rate revenues exclusive of fuel and rider revenues. The overall impact of the proposed

revenue requirement increase, considering both fuel and non-fuel revenues, is a 15.57% increase.

5. SWEPCO employed the 12-month period ending March 31, 2020, as its historical test year.

6. SWEPCO's proposed rate increase reflects incremental investment in generation since its last test year and incremental investment in transmission and distribution since SWEPCO last modified its transmission cost recovery factor (TCRF) and distribution cost factor (DCRF).

7. SWEPCO proposes revisions to many of its rate schedules and riders, requests that the Commission set SWEPCO's TCRF and DCRF to zero and establish the baseline values consisting of the inputs to the calculations that will be used to calculate SWEPCO's TCRF and DCRF in future proceedings.

8. Additionally, SWEPCO has announced the early retirement of its Dolet Hills Power Plant as of December 31, 2021. As a result, SWEPCO proposes rate treatments to address this early retirement.

9. SWEPCO requests an increase of $5 million over test year costs to expand its distribution vegetation management program.

10. SWEPCO also requests that the Commission approve certain policy-oriented proposals, including the establishment of a self-insurance reserve, deferred recovery of Hurricane Laura restoration cost, and certain charges billed to SWEPCO by the Southwest Power Pool (SPP).

11. SWEPCO provided notice of its application by publication for four consecutive weeks in newspapers having general circulation in each county of SWEPCO's Texas service territory. Individual notice of its proposed rate change was provided to all its retail customers by bill inserts and direct mailing. SWEPCO timely served notice of its statement of intent to change rates on all municipalities retaining original jurisdiction over its rates and services. Additionally, SWEPCO electronically provided notice to Commission Staff, the Office of Public Utility Counsel, and legal representatives of all parties to SWEPCO's most recent base case, Docket No 46449.

12. The following intervening parties participated in this docket: the Office of Public Utility Counsel; Cities Advocating Reasonable Deregulation (CARD); Eastman Chemical Company; Texas Industrial Energy Consumers; Nucor Steel-Longview; Texas Cotton Ginners Association; Northeast Texas Electric Cooperative, Inc. and East Texas Electric Cooperative, Inc.; Sierra Club and Dr. Lawrence Brough (Sierra Club); East Texas Salt Water Disposal Company (ETSWD) and East Texas Oil and Gas Producers; and Walmart Inc. Commission Staff also participated in this docket.

13. On October 30, 2020, the Commission referred this case to SOAH.

14. On November 19, 2020, SWEPCO filed an agreed motion to adopt procedural schedule in which it agreed to extend the statutory deadline to October 27, 2021.

15. On December 17, 2020, the Commission filed its preliminary order identifying the issues to be addressed in this proceeding.

16. In SOAH Order No. 2 filed on November 23, 2020, the SOAH ALJs set the hearing on the merits for May 19-28, 2021.

17. Collectively, the Commission's preliminary order and SOAH Order No. 2 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. SWEPCO timely filed with the Commission petitions for review of rate ordinances of the municipalities exercising original jurisdiction within its service territory. All such appeals were consolidated for determination in this proceeding.

19. The hearing on the merits commenced before four SOAH ALJs on May 19, 2021 and concluded on May 26, 2021.

20. The parties submitted initial post-hearing briefs on June 17, 2021, and reply briefs on July 1, 2021. Proposed findings of fact, conclusions of law, and ordering paragraphs were filed July 1, 2021, and the record closed on that date.

21. In accordance with Order No. 13, SWEPCO and CARD filed final rate-case-expense reports on July 6, 2021.

22. On July 20, 2021, Commission Staff filed its final supplemental direct testimony regarding rate-case expenses.

23. On July 27, 2021, SWEPCO filed its final supplemental rebuttal testimony on rate-case expenses, and CARD filed a statement of position on its final requested rate-case expenses.

24. The ALJs filed a proposal for decision in this docket on August 27, 2021.

24A. The ALJs filed a revised schedule D, originally attached to the proposal for decision, on August 31, 2021.

24B. Parties filed exceptions to the proposal for decision by October 7, 2021.

24E. On October 26, 2021, SWEPCO filed a letter agreeing to extend the statutory deadline in this case to December 9, 2021.

24F. Parties filed replies to exceptions by October 28, 2021.

24G. On November 9, 2021, the SOAH ALJs filed their response to the exceptions and replies and made certain modifications and clarifications to the proposal for decision.

24H. On December 7, 2021, Commission Staff filed its number run with updated rate schedules for SWEPCO based on the Commission's November 18, 2021 open meeting discussion.

24I. Commission Staff filed supplemental corrections to its number run on December 13 and December 21, 2021.

Rate Base and Invested Capital

Generation, Transmission, and Distribution Capital Investment

25. SWEPCO has invested approximately $636.7 million in its transmission system since the end of the test year (June 30, 2016) in its last base-rate case, Docket No. 46449.

26. SWEPCO has incurred a total amount of $143.5 million of distribution-capital investment placed in service during the period July 1, 2016, through March 31, 2020.

27. No party contested SWEPCO's transmission or distribution investment. The entirety of the transmission and distribution investment is used and useful in providing service to the public and is reasonable and necessary.

New Generation Capital Investment

28. SWEPCO regularly reviews capital projects that could provide economic, environmental, reliability, or safety-related benefits to SWEPCO's generating fleet. The first step in any capital addition evaluation is to research alternatives that may exist, and when warranted to perform cost-benefit analyses to estimate a project's value.

29. The Commission's electric utility rate filing package (RFP) for generating utilities schedule H-5.2b provides a list of every capital project with a value of greater than $100,000 placed in service since the close of the previous rate-case test year through the end of the test year in this case. This schedule provides a description of the reason for the capital investment, including: (1) immediate personnel safety requirement, (2) regulatory safety of operations requirement, (3) regulatory commitment (not classified in (2)), (4) plant efficiency improvement, (5) new building, (6) productivity improvement, (7) reliability, (8) economic, (9) habitability, and (10) other. The schedule also indicates whether a cost-benefit analysis was done for the project, which was done for a large majority of the projects.

30. SWEPCO uses multiple processes to ensure its generation operations and maintenance (O&M) expenses are reasonable. These include the use of budget controls, the review of cost trends, and tracking of staffing levels at its power plants.

31. RFP schedule H-1.2 provides a description of the O&M expenses incurred by FERC account, by plant, for each month of the test year. RFP schedule H-3 provides historical SWEPCO generation O&M expenses, by FERC account, by year since 2015. RFP schedule H-4 provides the major O&M projects undertaken during the test year by plant.

32. Except for Sierra Club's challenges to the test-year capital and O&M spending at the Flint Creek, Welsh, and Dolet Hills plants, no party contested the prudence of SWEPCO's generation-capital investments since the end of the Docket No. 46449 test year, nor the reasonableness of the test-year O&M expenses.

33. The legally competent, credible evidence presented in this case does not show that SWEPCO's capital investment at Flint Creek, Welsh, and Dolet Hills was imprudent, or that the O&M expenses were unreasonable or unnecessary.

34. SWEPCO's capital investment placed in service since the end of the Docket No. 46449 test year, including the test year capital spending at the Flint Creek, Welsh, and Dolet Hills plants, is prudent.

35. SWEPCO's O&M expenses incurred at its generating plants during the test year, including Flint Creek, Welsh, and Dolet Hills, are a reasonable and necessary component of SWEPCO's cost of service.

Retired Gas-Fired Generating Units

36. In January 2019, SWEPCO retired Knox Lee Unit 4. Additionally, in May 2020 SWEPCO retired Knox Lee Units 2 and 3, Lieberman Unit 2, and Lone Star Unit 1.

37. In deciding to retire these units, SWEPCO considered the age and condition of the units' equipment, the significant capital investment required for them to continue operating, and their relatively high cost to generate electricity. In light of those considerations, SWEPCO determined it was in the best interest of its customers to retire the generating units. The prudence of those retirement decisions was unchallenged.

38. SWEPCO accounted for these retirements in accordance with the FERC uniform system of accounts, which requires that the book cost of the unit retired be credited to electric plant and the same book cost be charged to the accumulated provision for depreciation applicable to that property.

39. SWEPCO used method described in finding of fact 38 to account for the retirement of Lieberman Unit 1 in Docket No. 46449, although this was uncontested and thus not specifically addressed by the Commission in that docket.

40. Although 16 TAC § 25.72(c) requires SWEPCO to maintain its books and records according to the FERC uniform system of accounts, this prescribed accounting treatment does not necessarily control the treatment of the assets for ratemaking purposes.

41. In Docket No. 46449, the Commission determined that: (1) because Welsh Unit 2 was retired and no longer generating electricity, it was not used by and useful to SWEPCO in providing electric service to the public; (2) because Welsh Unit 2 was no longer used and useful, SWEPCO could not include its investments associated with the plant in its rate base and earn a return on that remaining investment; (3) allowing SWEPCO a return of, but not on, its remaining investment in Welsh Unit 2 properly balances the interests of customers and shareholders with respect to a plant that no longer provides service; and (4) the appropriate accounting treatment that results in the appropriate ratemaking treatment was to record the undepreciated balance of Welsh Unit 2 in a regulatory-asset account rather than leaving it in accumulated depreciation.

42. Consistent with the Commission's rate treatment of the retired Welsh Unit 2 in Docket No. 46449, the net book values of the retired Lieberman Unit 2, Lone Star Unit 1, and Knox Lee Units 2, 3, and 4 should be removed from rate base, to cease earning a return and be placed in a regulatory asset.

43. The regulatory asset should be amortized over the four-year period in which the rates approved in this case are expected to be in effect.

Dolet Hills

44. Dolet Hills is a lignite-fueled generating unit located southeast of Mansfield, Louisiana, and jointly owned by SWEPCO; Cleco Power, LLC; Northeast Texas Electric Cooperative, Inc.; and Oklahoma Municipal Power Authority. CLECO is the majority owner and operator of Dolet Hills.

45. Dolet Hills went into commercial operation in 1986, and its previously established useful life extends until 2046.

46. Dolet Hills is fueled by lignite mined in the same area by Dolet Hills Lignite Company (DHLC), a SWEPCO subsidiary. An equity return on DHLC and associated taxes is currently included in SWEPCO's rate base.

47. An investment in the Oxbow Mine reserves is also included in SWEPCO's rate base.

48. In early 2020, SWEPCO and CLECO determined that all economically recoverable lignite at the Dolet Hills associated mines had been depleted, that mining operations should cease, and that Dolet Hills should be retired by the end of 2021.

49. In deciding whether to retire Dolet Hills, SWEPCO evaluated mining operations and the costs of operating the plant beyond 2021. SWEPCO studied the expected total SWEPCO system cost to serve customers, comparing the scenario where Dolet Hills continues to serve customers through 2046 versus through a December 31, 2021 retirement. The study determined that the expected least-cost path for SWEPCO and its customers lay in retiring the plant.

50. No party contested the prudence of SWEPCO's decision to retire Dolet Hills at the end of 2021. The decision was prudent.

51. Dolet Hills will be retired on December 31, 2021 and will continue providing service until that time. SWEPCO plans to continue operating the plant on a seasonal basis, principally during the peak summer months, as it has done in recent years. However, the plant remains available in case called upon by SWEPCO or CLECO's respective regional transmission organizations for reliability reasons.

52. Until its retirement, output from Dolet Hills will continue to be offered into the energy market year-round, incurring expenses required to ensure the unit is available to operate when called upon.

53. Although mining operations ceased in May 2020, SWEPCO's investment in the Oxbow reserves will continue to provide service until Dolet Hills' retirement, as the plant will continue to burn previously mined lignite to generate electricity.

54. Similarly, DHLC will continue to exist and deliver lignite to Dolet Hills, and SWEPCO will continue incurring this non-eligible fuel expense through the plant's retirement.

55. In this case, the rate year began on the relate-back date, March 18, 2021.

56. Dolet Hills, SWEPCO's Oxbow investment, and DHLC have provided service to customers during the rate year.

57. Good cause exists to make post-test-year reductions to SWEPCO's rate base to reflect, consistent with the Commission's rate treatment of Welsh Unit 2 in Docket No. 46449, that Dolet Hills, the Oxbow investment, and DHLC will cease to provide service to SWEPCO's customers when the plant retires on December 31, 2021.

58. It is appropriate to remove all cost recovery for Dolet Hills, the Oxbow investment, and DHLC from base rates and address these issues instead in a Dolet Hills rate rider.

59. Through the Dolet Hills rate rider, SWEPCO should be permitted, with respect to the period between March 18, 2021 (the date when the rates are effective) and December 31, 2021 (the date of Dolet Hills' retirement) (the operative-plant phase of the Dolet Hills rate rider), to recover the costs ordinarily permitted for an operating generating plant, including a return on the plant's net book value (including applicable accumulated deferred federal income taxes and unused materials and supplies), depreciation, and O&M. SWEPCO should similarly be permitted to continue earning a return on the Oxbow investment and the return on equity and associated taxes for DHLC. The charges in the Dolet Hills Rate Rider should be subject to true-up to reflect an updated-net-book value of Dolet Hills after its retirement and again after the plant is closed and final demolition costs are known.

60. With respect to the period after December 31, 2021 (the post-retirement phase of the Dolet Hills rate rider), the remaining net book values of Dolet Hills should be placed in a regulatory asset to be amortized without a return. All other cost recovery for Dolet Hills, the Oxbow investment, or DHLC under the Dolet Hills rate rider should cease, as the assets will no longer be providing service.

61. SWEPCO's recovery of Dolet Hills' remaining net book value (whether through depreciation during the operative-plant phase or recovery from the regulatory asset during the post-retirement phase) should be amortized in accordance with the asset's useful life ending in 2046.

62. DELETED.

63. Amortizing these assets in accordance with Dolet Hills' useful life ending in 2046 equitably balances the interests of SWEPCO and both its current and future customers.

64. It would be inequitable to SWEPCO's current customers to accelerate SWEPCO's recovery of these assets, as SWEPCO proposes to do, through offsetting the excess accumulated deferred federal income taxes (ADFIT) SWEPCO owes to its current customers and amortizing the balance over only four years.

65. SWEPCO's calculation and use of estimated demolition costs for Dolet Hills is reasonable.

Coal and Lignite Inventories

66. SWEPCO must maintain solid fuel inventories to assure a continuous supply of coal and lignite of appropriate quality, delivered at a reasonable cost over a period of years to promote the generation of the lowest cost per kilowatt-hour (kWh) of electricity, within the constraints of safety, reliability of supply, unit design, and environmental requirements.

67. Coal and lignite deliveries must be arranged so that sufficient fuel is available at all times to provide and maintain adequate and dependable electric service for SWEPCO's customers.

68. Setting inventory levels for SWEPCO's coal power plants (Welsh, Flint Creek, and Turk) and lignite power plants (Pirkey and Dolet Hills) based on the average level of burn from the test year would negatively impact SWEPCO's ability to reliably serve the needs of its customers and SPP and expose SWEPCO's customers to reliability risk.

69. Setting coal and lignite inventory targets for SWEPCO's coal and lignite power plants based on full-load burn ensures that adequate inventory is available to provide the necessary reliability for SWEPCO customers and SPP.

70. The target coal and lignite inventory levels SWEPCO requests to include in rate base are reasonable and necessary to ensure adequately reliable service to its customers.

71. However, because Dolet Hills will be retired on December 31, 2021, and consistent with the findings regarding the appropriate rate treatment of SWEPCO's investments in that plant, the Oxbow reserves, and DHLC, SWEPCO's lignite inventory for Dolet Hills should be removed from rate base and placed in the Dolet Hills Rate Rider; SWEPCO should recover a return on that inventory only during the operative-plant phase, and have no cost recovery for the inventory during the post-retirement phase.

72. Good cause exists to make these post-test year adjustments regarding SWEPCO's lignite inventory for Dolet Hills.

Prepaid Pension

73. SWEPCO records an additional cash investment in the pension trust fund as a prepaid pension asset in accordance with generally accepted accounting principles under Accounting Standards Codification 715-30. The prepaid pension asset is the cumulative additional pension cash contributions beyond the amount of pension cost.

74. No party has contested, and the evidence establishes, that an additional cash investment recorded as a prepaid pension asset should be included in rate base in accordance under PURA § 36.065.

NOLC ADFIT

75. SWEPCO records its stand-alone federal income tax net-operating-loss-carry-forward (NOLC) ADFIT on its books and records consistent with generally accepted accounting principles and the FERC uniform system of accounts.

76. For the period 2009 through the March 20, 2020 test year end, SWEPCO recorded a total net amount of stand-alone tax NOLC ADFIT of $455,122,490.

77. SWEPCO does not file a separate federal income tax return, as it is a subsidiary of AEP and included in AEP's consolidated federal income tax return.

78. SWEPCO participates in the AEP Tax Allocation Agreement for allocating the consolidated income taxes for AEP and its consolidated affiliates.

79. Under the AEP tax allocation agreement, through the March 20, 2020 test year end, SWEPCO received net-cash payments of $455,122,490 for the use of its tax net-operating losses to offset the taxable income of its affiliates on the AEP consolidated income tax return.

80. SWEPCO reflected its receipt of these tax allocation payments in its financial books and records by reducing the balance of its NOLC ADFIT to $0.

81. SWEPCO used the tax-allocation payments to finance plant assets now in its rate base. In essence, SWEPCO exchanged its previously recorded NOLC ADFIT asset (an asset that would reduce ADFIT and therefore increase rate base) for plant assets now included in rate base.

82. Under these circumstances, SWEPCO's proposed adjustment to recognize the $455,122,490 NOLC ADFIT again would effectively double the proper rate base impact of the NOLC ADFIT, contrary to normalization requirements.

83. Commission Staff's recommendation instead to reflect SWEPCO's book NOLC-ADFIT balance of $0 is consistent with PURA § 36.060, prevents SWEPCO from earning a return on the same $455,122,490 twice, and is consistent with normalization principles.

Excess ADFIT

84. The Tax Cuts and Jobs Act of 2017 reduced the corporate federal income tax rate from 35% to 21% effective January 1, 2018. This reduction, and the associated revaluation of the ADFIT balances previously recorded at 35% decreased due to the new 21% tax rate, results in excess ADFIT balances that should be returned to SWEPCO's customers.

85. The Commission determined in Docket No. 46449 that the regulatory treatment of excess deferred taxes resulting from the reduction in the federal tax rate would be addressed in SWEPCO's next base rate case. This proceeding is SWEPCO's next base rate base after Docket No. 46449.

86. In determining the amount of excess ADFIT available to its Texas customers, it is reasonable for SWEPCO to use the Texas retail allocation factor of 35.01% approved in Docket No. 46449.

87. Excess ADFIT related to differences in method and life for calculating depreciation expense for book versus tax purposes is considered to be *protected* excess ADFIT that cannot be returned to customers more rapidly than over the remaining lives of the assets that gave rise to the deferred taxes. All other excess ADFIT is considered to be unprotected, meaning there are no limitations on the timing or manner of returning it to customers.

88. SWEPCO began amortizing the protected excess ADFIT on January 1, 2018, by recording a provision for refund on its books as a regulatory liability related to the Texas jurisdictional portion of the excess ADFIT amortization.

89. SWEPCO should refund the balance of excess ADFIT available to return to customers (both unprotected ADFIT and accrued protected ADFIT) by first crediting the balance against any amount owed by customers because of the March 18, 2021 relate-back date in this proceeding, then refunding any excess ADFIT balance remaining over a six-month period, with carrying charges at the Commission-allowed weighted average cost of capital.

89A. The excess ADFIT refund should be allocated to rate classes in proportion to the amount of allocated ADFIT in the class cost of service study (CCOSS), and each rate class should receive

its full share of the refund. The application of any excess ADFIT credits against any amounts owed because of the relate-back of the rates approved in this proceeding should thus be conducted on a class-by-class basis.

90. The remaining balance of protected excess ADFIT should be returned to customers as an amortization included in rates, in a manner consistent with normalization requirements.

Accumulated Depreciation

91. SWEPCO's calculation of accumulated depreciation was not contested and is reasonable.

92. SWEPCO's adjustments to accumulated depreciation were not contested, are reasonable, and should be adopted.

Self-Insurance Reserve

93. SWEPCO requests approval of a self-insurance reserve pursuant to PURA § 36.064 and 16 TAC § 25.231(b)(1)(G).

94. SWEPCO's proposed self-insurance reserve would be funded by an annual accrual of $1,689,700, consisting of $799,700 to account for annual expected O&M losses from storm damage in excess of $500,000, plus $890,000 to build a target reserve of $3,560,000 in four years.

95. SWEPCO further proposes to charge its Texas jurisdictional Hurricane Laura restoration costs against the self-insurance reserve.

96. SWEPCO sufficiently demonstrated that self-insurance is a lower-cost alternative than commercial insurance and that customers will receive the benefits of the self-insurance plan.

96A. The Commission finds that SWEPCO's proposal to charge its Texas jurisdictional Hurricane Laura restoration costs against the self-insurance reserve is reasonable and is approved.

Rate of Return

97. A return on equity (ROE) of 9.25% will allow SWEPCO a reasonable opportunity to earn a reasonable return on its invested capital.

98. A 9.25% ROE is consistent with SWEPCO's business and regulatory risk.

99. SWEPCO did not demonstrate that either a size or credit risk adjustment was appropriate in setting its ROE.

100. A downward adjustment to the ROE is not warranted for the August 18, 2019 outage on SWEPCO's transmission system, which was caused by vegetation contact with a SWEPCO transmission line.

101. DELETED.

102. SWEPCO's proposed 4.18% cost of debt is reasonable.

103. A capital structure composed of 50.63% long-term debt and 49.37% equity is reasonable in light of SWEPCO's business and regulatory risks.

104. A capital structure composed of 50.63% long-term debt and 49.37% equity will be sufficient to attract capital from investors.

105. SWEPCO's overall rate of return should be as follows:

COMPONENT	CAPITAL STRUCTURE	COST OF CAPITAL	WEIGHTED AVERAGE COST OF CAPITAL
LONG-TERM DEBT	50.63%	4.18%	2.12%
COMMON EQUITY	49.37%	9.25%	4.57%
TOTAL	100.00%		6.69%

Financial Integrity (Ring-Fencing Protections)

106. AEP is a large corporation with several subsidiaries in multiple states, including both regulated and non-regulated entities. The effects of financial instability or weakness in one of these entities could affect not only AEP as the parent company, but also its subsidiaries, including SWEPCO.

107. Ring-fencing measures have been used to protect utilities from risky corporate parents or other affiliates to protect the utility's financial integrity and to ensure the utility can continue to operate and serve its customers.

108. Ordering the following financial protections is reasonable and necessary to protect SWEPCO's financial integrity and to ensure SWEPCO's ability to provide reliable service at just and reasonable rates:

a. SWEPCO will work to ensure that its credit ratings at Standard and Poor's and Moody's remain at or above SWEPCO's current credit ratings.

b. SWEPCO will notify the Commission if its credit issuer rating or corporate rating as rated by either Standard and Poor's or Moody's falls below investment-grade level.

c. SWEPCO will take the actions necessary to ensure the existence of a SWEPCO stand-alone credit rating.

d. SWEPCO will not share a credit facility with any unregulated affiliates.

e. SWEPCO's debt will not be secured by non-SWEPCO assets.

f. SWEPCO's assets will not secure the debt of AEP or its non-SWEPCO affiliates. SWEPCO's assets will not be pledged for any other entity.

g. SWEPCO will not hold out its credit as being available to pay the debt of any AEP affiliates.

h. Except for access to the utility-money pool and the use of shared assets governed by the Commission's affiliate rules, SWEPCO will not commingle its assets with those of other AEP affiliates.

i. SWEPCO will not transfer any material assets or facilities to any affiliates, other than a transfer that is on an arm's-length basis in accordance with the Commission's affiliate standards applicable to SWEPCO, regardless of whether such affiliate standards would apply to the particular transaction.

j. Without prior approval of the Commission, neither AEP nor any affiliate of AEP (excluding SWEPCO) will incur, guaranty, or pledge assets in respect of any incremental new debt that is dependent on: (1) the revenues of SWEPCO in more than a proportionate degree than the other revenues of AEP; or (2) the stock of SWEPCO. SWEPCO will not seek to recover from customers any costs incurred as a result of a bankruptcy of AEP or any of its affiliates.

109. These financial protections are similar to those agreed to by SWEPCO affiliate AEP Texas in Docket No. 49494, which were approved by the Commission. SWEPCO already abides

by most of the ring-fencing measures approved for AEP Texas and confirmed that SWEPCO is amenable to similar measures.

109A. After considering expert testimony and the evidentiary record, the Commission determined that two additional ring-fencing provisions proposed by Commission Staff are appropriate in order to insulate Texas ratepayers from business risks that do not provide ratepayer benefits:

a. A no cross-default provision, that SWEPCO's credit agreements and indentures will not contain cross-default provisions whereby a default by AEP or its other affiliates would cause a default by SWEPCO.

b. A no financial covenants or rating agency triggers related to another entity provision, that the financial covenants in SWEPCO's credit agreements will not be related to any entity other than SWEPCO. SWEPCO will not include in its debt or credit agreements any financial covenants or rating agency triggers related to any entity other than SWEPCO.

110. The evidence shows substantial benefit, and does not show a significant cost or harm, to ordering SWEPCO to employ the financial protections listed above.

Transmission O&M Expense

111. SWEPCO's test year transmission O&M expenses were $46,683,319, of which $8,636,052 were affiliate expenses.

112. SWEPCO's transmission O&M expenses were not contested by any party and are reasonable.

Transmission Expenses and Revenues under FERC-Approved Tariff

113. The SPP charges SWEPCO for the provision of transmission service to SWEPCO's customers. SWEPCO also receives payment from SPP for SPP members' use of SWEPCO's transmission facilities. These expenses and revenues are incurred and received pursuant to the FERC-approved SPP open access transmission tariff (OATT). The net amount that SWEPCO incurred under the SPP OATT during the test year is included in SWEPCO's requested cost of service in this proceeding.

Proposed Deferral of SPP Wholesale Transmission Costs

114. SWEPCO proposes to defer the portion of its approved transmission charges that is above or below the test-year level into a regulatory asset or liability for recovery in a future TCRF or rate case proceeding.

115. SWEPCO has not shown that the proposed recovery mechanism is needed here.

116. SWEPCO has not demonstrated that the approved transmission charges tracker is necessary for it to have a reasonable opportunity to earn a reasonable return above its necessary expenses.

Distribution O&M Expense

117. SWEPCO's adjusted test-year distribution O&M expenses including its own costs plus the charges from its service company affiliate, AEP Service Company, for distribution activities necessary to provide safe, reliable distribution services were $93,656,735.

118. The adjusted test-year distribution O&M costs reflect the amount necessary to perform distribution functions—for example, planning, construction, operation, and maintenance of the distribution system; and implementing SWEPCO's distribution-system-asset-management programs, reliability programs, and the vegetation-management program.

119. SWEPCO's distribution O&M expenses are reasonable and necessary.

Distribution Vegetation Management

120. SWEPCO's proposal to recover distribution O&M base-rate expenses of $14.57 million, consisting of the test-year amount of $9.57 million and an additional amount of $5 million, is reasonable.

121. The additional amount of distribution O&M expense in the amount of $5 million is reasonable and necessary to carry forward SWEPCO's vegetation-management program to improve overall reliability on targeted circuits and decrease outages caused by trees.

122. SWEPCO commits to spending the entirety of the increased amount of $5 million for distribution O&M expense solely on vegetation management.

123. DELETED.

123A. As part of its required annual filings under 16 TAC § 25.97(f), SWEPCO must include information on each occurrence of an outage related to vegetation contact with utility infrastructure and, for each of those instances, identify the length of time since vegetation management maintenance was most recently conducted. SWEPCO must also provide a list of every distribution line that has not received vegetation management treatment in the previous four years.

Generation O&M Expense

124. SWEPCO's proposed rate increase does not adjust the test year O&M expense for Dolet Hills to reflect the scheduled retirement of the plant by the end of 2021.

125. During the test year, SWEPCO incurred approximately $12.5 million in non-fuel O&M expense related to its 257 MW (40.28%) ownership share of Dolet Hills.

126. For Dolet Hills, SWEPCO's test-year-average-monthly O&M expense level is approximately $1.04 million per month.

127. After SWEPCO retires Dolet Hills at the end of 2021, SWEPCO will avoid significant non-fuel O&M expenses for operations at Dolet Hills.

128. The reduced utilization and ultimate retirement of Dolet Hills will result in known and measurable changes in the cost to maintain and operate the plant.

129. SWEPCO should recover O&M expense associated with the operation of Dolet Hills from March 18, 2021 (the relate-back date of rates in this proceeding) through December 31, 2021, at a monthly O&M expense level of $1.04 million per month.

130. SWEPCO should not recover O&M expense for Dolet Hills past its retirement in December 2021.

Payroll Expenses

131. SWEPCO's proposed base payroll is based on the salaries of its employees for the final pay period at the end of the test year (March 2020) plus post-test year pay increases of 3.0% for merit-eligible employees and 2.5% for hourly physical and craft employees, which were implemented in April 2020 and September 2020, respectively.

132. In June and July of 2020, retirement incentive packages were offered to certain SWEPCO and AEP Service Company employees. One SWEPCO employee and 189 AEP Service Company employees accepted the retirement incentive package.

133. Commission Staff proposes an adjustment of $544,331 in addition to SWEPCO's requested payroll adjustment based on a more recent time period, October 31, 2020, that was after the retirement incentives were offered.

134. It is appropriate to annualize SWEPCO's base payroll as of October 31, 2020, increasing SWEPCO's base payroll by $544,300 on a total company basis and $199,282 on a Texas retail jurisdiction basis, inclusive of the pay raise actually given by SWEPCO to its employees.

135. SWEPCO requests an increase of $3,804,876 to the test-year payroll expense allocated from AEP Service Company, based on an annualization of the end of test year headcount and inclusion of a merit increase.

136. Commission Staff proposes an adjustment of ($4,480,512) to the allocated AEP Service Company payroll, also based on annualization of the October 2020 AEP Service Company payroll that was after the retirement incentives were offered.

137. The impact of the retirements is reflected in Commission Staff's adjustment of $544,331 to SWEPCO's payroll and an adjustment of ($4,480,512) to SWEPCO's requested AEP Service Company allocated payroll.

138. SWEPCO failed to show it intended to replace the retired employees or that its employee headcount would recover or vary minimally from the test year. Rather, a material number of employees accepted the retirement package.

139. The retirement package and revised employee headcount is a material known and measurable change that merits an adjustment to payroll.

140. It is appropriate to annualize the base payroll for AEP Service Company payroll expense as of October 31, 2020, resulting in a decrease to SWEPCO's proposed base rates of $4,480,512 on a total company basis and $1,686,106 on a Texas retail jurisdiction basis.

Short-Term Incentive Compensation

141. SWEPCO's application excluded financial-based short-term incentive compensation expense and 50% of the financial-based funding mechanism related to its short-term incentive compensation plans.

142. SWEPCO's request to recover short-term incentive compensation expense should be adjusted to correct errors in accordance with the testimony of Commission Staff witness Ruth Stark, which SWEPCO does not oppose.

143. SWEPCO's requested short-term incentive-compensation expense, adjusted in accordance with the testimony of Commission Staff witness Ruth Stark, is approved.

Long-Term Incentive Compensation

144. SWEPCO adjusted its test year long-term incentive compensation expenses to remove the 75% of those expenses related to performance units but retained the 25% related to restricted stock units.

145. Restricted stock units are not based on financial measures and are appropriate to include in SWEPCO's rates.

146. SWEPCO's requested long-term incentive compensation expense is approved.

Severance Costs

147. In calendar years 2017 and 2018, SWEPCO incurred $0 in direct severance costs. During the test year, SWEPCO incurred $767,074 in direct severance costs.

148. SWEPCO's $767,074 in direct severance costs during the test year is atypical and does not represent normal levels of direct severance costs.

149. It is appropriate to average three years of direct severance costs to calculate SWEPCO's direct allowable severance costs, which equates to $252,033.

150. AEP Service Company allocates severance costs to SWEPCO. During the test year relative to calendar year 2017 and 2018, AEP Service Company charged severance costs to SWEPCO that increased from less than $550,000 for the two years prior to $1,460,876 during the test year.

151. SWEPCO's $1,460,876 in allocated severance costs during the test year is atypical and does not represent normal levels of allocated severance costs.

152. It is appropriate to average three years of allocated severance costs to calculate SWEPCO's allowable-allocated severance costs, which equates to $824,300.

Pension Expense

153. SWEPCO's requested cost of service pension expense reflects the costs being recorded by SWEPCO in 2020 as presented in the 2020 actuarial studies, which are the latest available actuarial studies performed by Willis Towers Watson, SWEPCO's independent actuary. SWEPCO applies the test-year actual payroll expense capital ratio to these 2020 costs to determine the pro forma level of expense to include in the cost of service. SWEPCO's requested cost of service pension expense is reasonable.

Other Post-Retirement Benefits Expense

154. SWEPCO's requested other post-employment benefits expense reflects the costs being recorded by SWEPCO in 2020 as presented in the 2020 actuarial studies, which are the latest available actuarial studies performed by Willis Towers Watson. SWEPCO's requested other post-employment benefits expense is reasonable.

Depreciation and Amortization Expense

Net Salvage/Demolition Study

155. The use of a 10% contingency factor in SWEPCO's demolition study to determine terminal-net-salvage amounts for SWEPCO's generating plants is reasonable.

156. It is reasonable for SWEPCO to escalate the terminal-net-salvage amounts in the demolition study (which are stated in year-end 2020 dollars) to the expected final retirement date of each plant using a 2.22% inflation rate from the *Livingston Survey* dated December 2019, published by the research department of the Federal Reserve Bank of Philadelphia.

Curve Life Combinations — Mass Property Accounts

157. It is reasonable to apply an S0.0-68 Iowa curve-life combination for FERC account 353, transmission station equipment.

158. It is reasonable to apply an S1.5-74 Iowa curve-life combination for FERC account 354, transmission towers and fixtures.

159. It is reasonable to apply an L1.5-49 Iowa curve -ife combination for FERC account 355, transmission poles and fixtures.

160. It is reasonable to apply an R2.0-70 Iowa curve-life combination for FERC account 356, overhead conductors and devices.

161. It is reasonable to apply an S-.5-55 Iowa curve-life combination for FERC account 364, poles, towers, and fixtures.

162. It is reasonable to apply an R4.0-80 Iowa curve-life combination for FERC account 366, underground conduit.

163. It is reasonable to apply an R3.0-46 Iowa curve-life combination for FERC account 367, underground conductor.

164. It is reasonable to apply an R3.0-59 Iowa curve-life combination for FERC account 369, services.

165. It is reasonable to apply an L0.0-15 Iowa curve-life combination for FERC account 370, meters.

Amortization Expense

166. SWEPCO's amortization expense related to an intangible asset that was fully amortized as of the end of the test year should be excluded from SWEPCO's revenue requirement.

Purchased Capacity Expense

167. During the test year, SWEPCO continued to purchase 50 MW of capacity under its long-term purchase power agreement with Louisiana Generating Company (formerly Cajun Electric Power Cooperative) (the Cajun contract). That agreement began in 1992. These capacity costs have been consistently recovered through base rates.

168. During the test year, SWEPCO purchased the product designated as operating reserve capacity under the Cajun contract and counted that capacity in SWEPCO's compliance with SPP's capacity reserve requirements. During the test year SWEPCO did not purchase any operating reserve energy under the Cajun contract.

169. The operating reserve capacity under the Cajun contract is distinguishable from regulation and operating reserve services procured in the SPP independent monitor day-ahead and real-time market.

170. The costs that SWEPCO incurred during the test year under the Cajun contract continue to be properly recovered in base rates.

171. The cost of energy incurred under SWEPCO's wind-energy contracts has been collected through SWEPCO's fuel factor and reconciled as energy purchases since their inception, starting with Docket No. 40443 for the Majestic renewable energy purchase agreements.

172. According to the SPP planning criteria, the amount of capacity that may be accredited to a renewable resource is determined by a set of formulas using the historical output of that particular facility and updated over time.

173. The Commission should continue to account for the costs incurred under these wind contracts as energy.

Affiliate Expense

174. SWEPCO incurred a total of $87,634,578 in adjusted total-company test-year affiliate charges: $85,227,881 in charges from AEP Service Company and $2,406,697 from other affiliates.

175. Commission Staff proposed an adjustment to SWEPCO's affiliate expense that SWEPCO did not oppose.

176. As adjusted by Commission Staff, SWEPCO's affiliate expenses are reasonable and necessary for each item or class of items, are allowable, are charged to SWEPCO at a price no higher than was charged by the supplying affiliate to other affiliates, and the rate charged was a reasonable approximation of the cost of providing the service.

Federal Income Tax Expense

177. SWEPCO's method of calculating its federal income tax expense is reasonable.

178. The amount of federal income tax SWEPCO included in its cost of service was calculated in accordance with the provisions of PURA §§ 36.059 and 36.060.

179. No party challenged the inclusion of federal income tax expense in SWEPCO's cost of service.

Ad Valorem Taxes

180. SWEPCO's requested effective ad valorem tax rate excludes Texas jurisdictional differences that would decrease the effective rate but includes Texas jurisdictional differences that increase the effective rate.

181. The effective ad valorem tax rate should be synchronized with the plant to which the rate is to be applied.

182. Including SWEPCO's proposed Texas jurisdictional plant differences related to depreciation and allowance for funds used during construction rates in the plant balance used to calculate ad valorem taxes requires that such jurisdictional differences be included in the determination of the effective ad valorem tax rate.

183. Including SWEPCO's proposed Texas jurisdictional plant differences related to depreciation and allowance for funds used during construction rates in the determination of the effective ad valorem tax rate does not result in other states subsidizing Texas customers.

184. The appropriate effective ad valorem tax rate that includes the Texas jurisdictional differences in the determination of the rate is 0.961262%.

Payroll Taxes

185. It is reasonable to synchronize payroll taxes with adjustments to SWEPCO's payroll expenses.

186. Incentive compensation is part of SWEPCO's payroll expenses.

187. A potential offset of incentive compensation with additional base pay by SWEPCO in the future is speculative.

188. Payroll tax on disallowed incentive compensation is properly borne by shareholders.

189. An adjustment of ($258,162) to SWEPCO's payroll tax expense is appropriate. This synchronizes payroll taxes with the adjustments to payroll and incentive compensation expenses as recommended by Commission Staff.

Gross Margin Tax

190. SWEPCO calculates the Texas gross receipts (margin) tax amount using an effective rate derived from test-year payments and test-year Texas retail base and fuel revenues.

191. Revenue related taxes should be updated and synchronized with the final revenue requirement set in this case.

Allocated Transmission Expenses Related to Retail Behind-the-Meter Generation

192. To serve its retail and wholesale customers, SWEPCO purchases network integration transmission service (NITS) from SPP for the use of SPP's transmission system.

193. SPP charges for NITS pursuant to its FERC-approved OATT.

194. SWEPCO is obligated to pay SPP the charges SPP bills to SWEPCO pursuant to the SPP OATT for the provision of transmission services to SWEPCO.

195. SPP allocates the cost of using its transmission system to NITS customers (referred to as network customers in the OATT) based on the load-ratio share of each customer's monthly network load to the total system load at the time of the monthly system peak.

196. To obtain the data necessary to make this allocation, SPP requires network customers, such as SWEPCO, to submit their monthly network load data to SPP.

197. In October 2018, SWEPCO changed how it reports its monthly network load to SPP by adding load served by retail (BTMG).

198. In this context, BTMG refers to a generation unit that is behind the transmission system meter—not directly connected to the bulk transmission system—and is intended to serve all or part of the capacity or energy needs for the load behind the meter without withdrawing energy from the SPP transmission system.

199. Retail BTMG (in contrast to wholesale BTMG) is on-site generation operated by a retail end-use customer to serve its own local load requirements. Retail BTMG may be large scale, such as an industrial customer with a cogeneration facility, or small scale, such as a residential rooftop solar facility.

200. When retail BTMG is excluded from a network customer's monthly load report, it is reported on a *net* basis, whereas when retail BTMG is included, it is reported on a *gross* basis.

201. SPP provided educational information to its stakeholders, including SWEPCO, clarifying that FERC policy and the SPP OATT do not exclude or net BTMG from the network load calculation.

202. At this time, SWEPCO is only reporting the retail BTMG load of one customer, Eastman, which is located in SWEPCO's Texas service area.

203. Eastman operates an on-site cogeneration facility that generates approximately 150 MW of power to supply the full =-load requirements of Eastman's operations. Eastman is a *qualifying facility* under the Public Utility Regulatory Policies Act of 1978.

204. During scheduled maintenance outages and forced or unscheduled outages when Eastman's generation is not operating, Eastman purchases standby electricity service from SWEPCO under SWEPCO's supplementary, backup, maintenance and as-available power service tariff. Eastman coordinates routine maintenance outages with SWEPCO to avoid system peaks.

205. Due to the configuration of Eastman's campus and BTMG, Eastman uses a SWEPCO-owned transmission line to serve all the load at its campus, but its use of the line is incidental and is not imposing new costs on SWEPCO's system.

206. During the test year, the network load that SWEPCO reported to SPP included 146 MW of load served by Eastman's BTMG. The higher reported network load resulted in SPP allocating a higher share of its transmission system costs to SWEPCO, which was reflected in SWEPCO's NITS charges in the test year.

207. There is a lack of consensus among SPP and its network customers regarding how to report retail BTMG load to SPP under the OATT.

208. Determining whether SWEPCO's NITS charges are pursuant to the OATT necessarily requires an interpretation of the OATT.

209. DELETED.

210. DELETED.

211. DELETED.

212. DELETED.

213. The NITS charges are part of SWEPCO's overall transmission costs, which SWEPCO allocates jurisdictionally among Texas, Arkansas, and Louisiana.

214. SWEPCO did not identify the increase in NITS charges attributable to reporting Eastman's BTMG load.

215. To recover the additional cost, SWEPCO proposed to change how it allocates its transmission costs by imputing Eastman's BTMG load to the Texas jurisdiction for jurisdictional allocation and to the large lighting and power-transmission (LLP-T) class for class allocation.

216. Adding Eastman's BTMG load to the Texas jurisdiction would increase Texas's share of SWEPCO's transmission costs by $5.7 million, with corresponding reductions to the Arkansas and Louisiana jurisdictions.

217. Adding Eastman's BTMG load to the LLP-T class would have a larger impact, increasing that class's share of SWEPCO's transmission costs by $7.5 million, with corresponding reductions to the remainder of SWEPCO's classes.

218. Adjusting the jurisdictional and class allocators for SWEPCO's overall transmission costs results in a shift of not just the SPP-related costs, but also the non-SPP-related costs.

219. SWEPCO did not explain why adjusting the allocations was the appropriate method to recover its increased NITS charges, or why reporting Eastman's BTMG load would impact non-SPP-related costs.

220. SWEPCO has 187 retail BTMG customers in Texas, including Eastman. Of these customers, at least three have cogeneration facilities (including Eastman) and the rest are commercial or residential solar facilities.

221. SWEPCO has retail BTMG customers in Arkansas and Louisiana, including at least one industrial retail BTMG customer (a paper mill) in Arkansas, and solar retail BTMG customers in both Arkansas and Louisiana.

222. Adding retail BTMG load solely to Texas likely results in the Texas jurisdiction receiving a higher allocation of SWEPCO's transmission costs than if SWEPCO had treated each jurisdiction consistently. This inconsistency is not attributable to SPP requiring network customers to report retail BTMG load, as SWEPCO presented evidence that all retail BTMG load should be reported.

223. SWEPCO's decision to increase the Texas jurisdictional allocator, but not the Arkansas and Louisiana jurisdictional allocators, is unreasonable and results in unreasonably discriminatory rates for Texas customers.

224. SWEPCO's corresponding change to the LLP-T class allocator is unreasonable and results in unreasonably discriminatory rates among SWEPCO's Texas customers.

225. SWEPCO's proposals to allocate transmission costs at both the jurisdictional and class levels by adding Eastman's BTMG load to the Texas jurisdiction and LLP-T class, respectively, are not reasonable, necessary, and non-discriminatory.

226. Eastman's BTMG load should be removed when performing the jurisdictional and class allocations of transmission costs.

Billing Determinants

227. The Commission's RFP accepts the use of estimated billing units.

228. SWEPCO used estimated billing determinants to address potential customer migration among rate classes between rate cases.

229. SWEPCO's initial filing included pro forma adjustments to the test-year billing determinants for all of the known and measurable items at the time this case was filed.

230. The ongoing effects, if any, of the COVID-19 pandemic on SWEPCO's billing determinants are not known and measurable and do not reflect conditions that are likely to prevail when the rates approved in this case are in effect.

231. ETSWD's proposal that SWEPCO should update its class-cost-of-service study (CCOSS) to incorporate new data and account for the enduring work-from-home shift and other effects of COVID-19 is not reasonable because the effects of COVID-19 are not known and measurable.

232. ETSWD's alternative proposal that the Commission instruct SWEPCO to recalculate and adjust its CCOSS using the data provided in SWEPCO's response to ETSWD request for information 3-1 also is not reasonable because the effects of COVID-19 are not known and measurable.

233. A pro forma adjustment to billing determinants should not be used to address a temporary event, because a pro forma adjustment is intended to ensure that test-year data better represents a utility's ongoing operations.

234. Customers who permanently left SWEPCO during the test year should be removed from SWEPCO's proposed billing determinants.

235. Except in an extraordinary event not present in this case, a pro forma adjustment to remove a customer that permanently left SWEPCO after the close of the test year should not be made because that event was not known or measurable during the test year.

236. SWEPCO's adjusted test-year billing determinants are reasonable and should be used in designing rates resulting from this case.

Functionalization and Cost Allocation

237. The allocation methodologies and processes used in SWEPCO's jurisdictional cost of service study and CCOSS reflect criteria generally used to determine the appropriateness of allocation methodologies.

238. The allocation methodologies and processes used in SWEPCO's jurisdictional cost of service study and CCOSS are consistent with the development of the jurisdictional cost of service study and CCOSS ordered by the Commission in Docket No. 46449 and with the base rates approved by the Commission in that docket and updated in SWEPCO's related compliance filing in Docket No. 48233.

Jurisdictional Allocation

239. Until this rate case, SWEPCO has not proposed to include the self-served load of any retail customer in allocating transmission costs in any of its jurisdictions.

240. SWEPCO's proposal to increase the allocation to Texas customers by $5.7 million through the inclusion of the self-served load of a single customer is unreasonable.

241. The jurisdictional allocation of transmission costs to Texas retail customers should be established by using the actual load served by SWEPCO in each of its jurisdictions.

242. SWEPCO's allocation of Eastman's load served by its retail BTMG should be removed from the jurisdictional cost of service study.

243. SWEPCO appropriately removed the allocation of certain distribution investments from the wholesale class.

Class Allocation

244. SWEPCO corrected its CCOSS in rebuttal testimony to use a system-load factor based on the single annual coincident peak in the average and excess demand four-coincident peak methodology.

245. The use of the single annual coincident peak in calculating the system load factor is consistent with Commission precedent and cost causation.

246. SWEPCO properly accounted for customer prepayments in its rebuttal CCOSS.

247. SWEPCO appropriately does not allocate major-account representative costs to the residential class.

248. In its rebuttal CCOSS, SWEPCO appropriately corrected an error regarding its allocation of line-transformer costs.

249. SWEPCO's correction to the line-transformer allocation is not contrary to the Commission's decision in Docket No. 46449.

250. Commission Staff's proposal for a four-year phase-in of rate increases to move all classes to their relative rate of return ignores that customers' consumption patterns change

year-to-year and would cause some classes to incur significant rate increases each year for four years.

251. DELETED.

252. Three customer classes historically have been well below their relative rates of return as shown though SWEPCO's CCOSS, including its rebuttal CCOSS: the cotton gin class, the oilfield secondary class, and the public street and highway lighting class.

253. It is appropriate to require SWEPCO to provide direct testimony in its next base-rate case addressing why these three classes continue to be well below unity and address whether there are measures that can be taken in the class allocation (or rate design) process to address this situation, other than simply applying gradualism.

254. Based on the evidence in this case, SWEPCO's proposed class allocation to address classes that are not at a unitary relative rate of return is reasonable.

255. None of the $5.7 million in transmission costs SWEPCO allocated to the Texas retail jurisdiction and in its CCOSS through its retail BTMG proposal should be allocated to any Texas retail customers.

Municipal Franchise Fees

256. SWEPCO develops the effective rate for municipal franchise fees based on test year actual municipal franchise taxes paid, less the amount in excess of the base amount and test year actual kWh sales.

257. SWEPCO applies the effective rate for municipal franchise fees to the test-year-adjusted kWh sales to determine the pro forma amount to include in SWEPCO's cost of service.

258. SWEPCO's allocation of municipal franchise fees was not contested by any party and is reasonable.

Revenue Distribution

259. The class revenue distribution is the rate design mechanism by which a utility's approved annual revenue requirement is assigned to the customer classes.

260. The revenue distribution also determines the revenue requirement targets for each class.

261. The percent increase in base rates for each class is based on its revenue deficiency as determined by the CCOSS.

262. The revenue deficiency determines the revenue requirement needed to bring each class to an equalized return.

263. The revenue requirement at an equalized return is the amount of revenue needed from each class to recover the full costs of serving that customer class.

264. The equalized revenue requirement and revenue change based on that requirement is the starting place for the revenue distribution. Other factors may also be taken into consideration such as customer migration, and a potential need to moderate a rate increase through rate gradualism.

265. SWEPCO's proposed rebuttal-revenue distribution moves all customer classes closer to cost of service.

266. All present base-rate-related revenues, inclusive of TCRF and DCRF revenues, are the appropriate starting point for evaluating any rate increase.

267. In Docket No. 46447, SWEPCO was required to present its rate change request in this case such that its then-present revenues show the total present revenues inclusive of the TCRF and DCRF revenues.

Rate Moderation/Gradualism

268. All parties to this case agree that some form and level of rate moderation should be applied to the revenue distribution.

269. The design of rates within each rate schedule should be cost-based and informed by the results of the CCOSS, subject to gradualism.

270. Gradualism and rate moderation are appropriate exceptions to this requirement when a class's proposed rate increase leads to *rate shock*.

271. A proposed rate increase of 43% or less in any one class is an appropriate upper percentage to apply in this case for the gradualism or rate moderation evaluation.

272. SWEPCO's approach of grouping major rate classes for purposes of implementing the revenue distribution was approved by the Commission in SWEPCO's two most recent base-rate proceedings, Docket Nos. 40443 and 46449.

273. SWEPCO's proposed rate moderation methodology, which reduces the subsidization among individual rate classes, is reasonable and should be adopted.

274. Commission Staff's proposed four-year phased-in method to move all customers to unity does not account for the fact that customers' consumption patterns change year-to-year and would result in significant rate increases every year over the four-year phased-in period to some customers.

275. Commission Staff's proposed four-year phased-in method should not be accepted.

Rate Design and Tariff Changes

276. In general, SWEPCO's proposed rate design retains the rate structures and relationships approved by the Commission in SWEPCO's two most recent base rate proceedings, Docket Nos. 40443 and 46449.

277. SWEPCO's proposed rate design provides a reasonable basis for establishing rates in this proceeding.

278. SWEPCO has not met its burden of proof to justify removing the 50 kilowatt (kW) maximum demand cap in the GS rate schedule.

279. SWEPCO should not be required to revise its rate schedules in its next rate case to preclude the potential for customer migration between rate schedules or between any other customer classification.

280. SWEPCO should be required to address the customer migration issue in more detail in its next base-rate-case filing, including which classes are structured to allow migration among classes even if customers' loads or operations do not change, why customers migrate among classes, and how SWEPCO adjusts, or estimates, its billing determinants to account for customer migration among rate classes between base-rate cases.

281. SWEPCO has not explained or justified why it is appropriate, in this case, to collect fixed demand-related costs through energy charges in the large power secondary class.

282. SWEPCO offers a rate option for cotton gin customers that allows the application of the minimum monthly bill only during the ginning season as defined as November through February.

283. In SWEPCO's prior fuel reconciliation proceeding, Docket No. 47553, SWEPCO agreed to impute the value of renewable energy credits and treat them as a base-rate expense.

284. SWEPCO should revise the renewable energy credit rider to allow a customer to link its renewable energy credits to specific renewable resources.

285. SWEPCO must implement a renewable energy credit opt-out tariff that would refund renewable energy credit costs to transmission-voltage customers who have opted out.

286. The renewable energy credit opt-out charge should be calculated based on an energy allocator for renewable energy credit costs, consistent with how renewable energy credits are generated and set at a credit of 0.0069 cents per kWh for the Commercial Class and a credit of 0.0066 cents per kWh for the Industrial Class.

287. SWEPCO did not perform or provide a study justifying its proposal to increase the reactive-demand charge by 29.4%.

288. SWEPCO has not met its burden of demonstrating that there is a cost basis for increasing the reactive-demand charge in the large lighting and power (LLP) rate schedule.

289. Under SWEPCO's residential plug-in electric vehicles rider, an installed sub-meter separately measures plug-in electric-vehicle kWh usage while a standard meter measures total residence kWh usage.

290. SWEPCO has met its burden of proof regarding the residential plug-in electric-vehicles rider.

291. ETSWD's request that the Commission direct SWEPCO to implement a retail-choice pilot project is moot based on the Commission's denial of ETSWD's request for a declaratory ruling on this matter in Docket No. 51257.

Transmission Rate for Retail Behind-the-Meter Generation

292. Because SWEPCO's proposal to allocate to any customer or class the SPP charges related to Eastman's load served by its retail BTMG should be rejected, it is not appropriate for SWEPCO to implement a synchronous self-generation load rate schedule or rate.

Baselines for Cost-Recovery Factors

293. A TCRF is a rate mechanism that allows an electric utility outside of the Electric Reliability Council of Texas region to periodically update its recovery of transmission costs.

294. SWEPCO is eligible under 16 TAC § 25.239 to have a TCRF.

295. TCRF baseline values should be set during the compliance phase of this docket, after the Commission makes final rulings on the various contested issues that may affect this calculation.

296. A DCRF is a rate mechanism that allows an electric utility to periodically adjust its rates for changes in certain distribution costs.

297. The Commission has adopted 16 TAC § 25.243 to implement PURA § 36.210. The DCRF rule allows an electric utility not offering customer choice (SWEPCO) to file an application for a DCRF at any time other than April and May.

298. DCRF baseline values should be set during the compliance phase of this docket, after the Commission makes final rulings on the various contested issues that may affect this calculation.

299. A generation cost recovery rider is a rate mechanism authorized under PURA § 32.213 that allows an electric utility to recover its investment in a power generation facility outside of a base-rate proceeding.

300. The baseline values for a subsequent implementation of the generation cost recovery rider should be established during the compliance phase of this docket, after the Commission makes final rulings on the various contested issues that may affect this calculation.

Rate-Case Expenses

301. SWEPCO and CARD sought to recover a total of $3,769,007 in rate-case expenses for this docket as well as Docket Nos. 49042, 46449, 40443, 47141, and 50997, consisting of

$2,740,315 for SWEPCO's own rate-case expenses and $1,028,692 in rate-case expenses paid or to be paid by SWEPCO to CARD for its participation in these dockets and reflected on SWEPCO's and CARD's rate-case expense reports.

302. The Commission's order in Docket No. 47141 authorized CARD to collect up to an additional $2,500 in rate-case expenses in that docket after April 13, 2020.

303. In this docket, CARD originally requested to recover $6,321 in rate-case expenses incurred in Docket No. 47141 after April 13, 2020.

304. CARD's request to recover $6,321 for Docket No. 47141 rate-case expenses should be reduced to $2,500.

305. SWEPCO seeks to recover $65,167 in rate-case expenses in Docket Nos. 51415 and 40443 that include rates in excess of $550 per hour for two outside attorneys in those dockets.

306. The Office of the Attorney General issued a memorandum in 2016 that limited the maximum outside counsel per-hour fee to $525 but allowed the Deputy Attorney General to authorize a higher fee. This memorandum was addressed to, among others, state agencies and addressed "Outside Counsel Contract Rules and Templates."

307. The Office of the Attorney General issued a follow-up memorandum, in 2019 that did not increase the $525 per-hour fee cap. This follow-up memorandum also was directed to state agencies and addressed Outside Counsel Contract Rules and Templates.

308. SWEPCO did not meet its burden of proof to show that the nature, extent, and difficulty of the work performed by the attorneys who charged in excess of $550 per hour justified hourly rates in excess of $550 in this base-rate case.

309. The rates SWEPCO paid to outside attorneys in excess of $550 per hour are excessive and not reasonable.

310. The fact that other entities may be willing to pay an attorney a rate in excess of $550 per hour does not mean that the rate is reasonable and not excessive in the context of a Commission electric utility rate proceeding.

311. SWEPCO's request to recover $65,167 in rate-case expenses related to outside attorney fees billed in excess of $550 per hour should be denied.

312. The total amount of rate-case expenses that SWEPCO and CARD should recover in this docket is $3,700,021.

313. SWEPCO should reimburse CARD for its requested rate-case expenses, except that CARD's recovery related for Docket No. 47141 is $2,500, not $6,321.

314. It is reasonable for SWEPCO to recover the $3,700,021 in rate-case expenses authorized in this docket through its proposed rate case surcharge rider.

315. Any trailing rate-case expenses related to Docket No. 51415 that are incurred after the dates of the rate-case expenses addressed in the final reports filed in this docket should be recorded as a regulatory asset and deferred for consideration in a future SWEPCO docket.

315A. The Office of Policy and Docket Management (OPDM) filed a memo on October 14, 2021, requesting SWEPCO to identify or file evidence in the record reflecting the affidavit or testimony of a licensed attorney supporting the reasonableness of $2,740,315 for SWEPCO's own rate-case expenses incurred through May 2021.

315B. On October 22, 2021, SWEPCO filed the affidavit of Melissa A. Gage, attesting to the reasonableness of SWEPCO's rate-case expenses, and a motion to admit the filing as evidence.

315C. On November 2, 2021, the Commission ALJ filed Order No. 2 admitting the affidavit of Melissa A. Gage into evidence.

Other Issues

316. It is uncontested and reasonable that the final approved return on equity should be included in the factoring-rate calculation to synchronize factoring expense properly to the approved revenue requirement.

317. Commission Staff's proposed adjustments of ($1,164,427) to remove carrying charges paid by SWEPCO associated with affiliate or shared assets and ($530,384) to remove carrying charges SWEPCO received from its affiliates is uncontested and reasonable.

318. Commission Staff's adjustment to update the customer deposit interest amount to incorporate the Commission-approved 2021 interest rate is uncontested and reasonable. In

this case that is 0.61%, which results in an adjustment of ($1,041,156) to SWEPCO's request.

319. In accordance with the Commission's decisions in Docket Nos. 40443 and 46449, SWEPCO removed supplement executive retirement plan expense from its requested cost of service, which is reasonable.

320. In accordance with the Commission's decisions in Docket Nos. 40443 and 46449, Commission Staff recommended an adjustment for executive perquisites. Based on Commission Staff's adjustment, SWEPCO agreed to remove $20,595 from its revenue requirement related to executive perquisites. This adjustment is reasonable.

321. SWEPCO has announced that the Welsh plant will cease coal-fired operations in 2028 in light of the Coal Ash Combustion Residual Rule and the Effluent Limitations Guidelines.

322. SWEPCO has not yet determined whether natural gas conversion of the Welsh plant is in the customers' best interest.

323. If such a conversion to natural gas were to occur in the future, SWEPCO will request Commission authorization to include the costs associated with that conversion in customer rates in a future proceeding.

324. SWEPCO has not included any construction work in progress in its requested rate base.

325. RFP schedule E-4 contains the calculation of SWEPCO's cash working-capital allowance included in rate base.

326. The lead-lag study used in this proceeding is the one approved in SWEPCO's last base-rate case, Docket No. 46449.

327. The lead-lag study conducted by SWEPCO considered the actual operations of SWEPCO, adjusted for known and measurable changes, and is consistent with 16 TAC § 25.231(c)(2)(B)(iii).

328. At the time the current proceeding was filed, less than five years had passed since SWEPCO's last lead-lag study. By using the last approved study, SWEPCO estimates that it saved around $75,000 in rate-case expenses.

329. It is uncontested and reasonable that cash working capital should be updated and synchronized with the final revenue requirement.

330. Commission Staff's adjustment of ($46,306) to administrative and general O&M expense, specifically for regulatory commission expense, is not contested and is reasonable.

331. SWEPCO's federal income taxes were calculated consistent with PURA § 36.059 including treatment of tax savings derived from liberalized depreciation and amortization, investment tax credit, or similar methods.

332. SWEPCO's expenditures for advertising, contributions, memberships, and donations included in its cost of service meet the standard and thresholds set forth in 16 TAC § 25.231(b)(1)-(2).

333. SWEPCO uses advertising to convey information regarding safety and reliability to its customers and to support local initiatives.

334. SWEPCO did not include any prohibited advertising expenses in its request.

335. SWEPCO makes charitable contributions toward education, community service, and economic development in and for the benefit of the communities in which it operates. These costs are reasonable and consistent with the Commission's requirements and thresholds for recovery

336. SWEPCO membership expenses are reasonable and comply with the Commission's standards.

337. No party raised an issue with respect to SWEPCO's competitive affiliates.

338. SWEPCO is not seeking to include in rates any costs previously deferred by a Commission order.

339. SWEPCO's request to defer the portion of its ongoing net SPP open access transmission tariff bill that is above or below the net-test-year level is not reasonable and should be denied.

340. SWEPCO proposed an optional residential time-of-use rate schedule as a pilot available to residential customers.

341. SWEPCO proposed a commercial time-of-use rate schedule for commercial loads of 100 kW or greater.

342. The pilot projects will gauge interest and utilization of the time-of-use format by customers that do not qualify for SWEPCO's off-peak rider for the lighting and power, LLP, and metal melting service classes. Participating customers can manage certain energy costs by shifting energy consumption to off-peak periods.

343. The proposed time-of-use rate schedule and design is reasonable and appropriate under 16 TAC § 25.234.

344. SWEPCO proposes to update its economic development rider.

345. SWEPCO's proposed tariff revisions to attract loads from a variety of businesses with different load requirements in order to spur economic growth in its service territory and provide long-term benefits to SWEPCO customers are reasonable and appropriate.

346. The proposed tariff revisions are consistent with the Commission's standards including 16 TAC § 25.234.

347. SWEPCO is not filing a fuel reconciliation proceeding in this docket; therefore, the schedules dealing with fuel reconciliation proceedings are not applicable. Accordingly, SWEPCO's requested waiver of the portions of the RFP that request information related to fuel reconciliation proceedings should be granted.

348. SWEPCO obtained authorization in Docket No. 50917 to waive the requirement that it file an RFP Schedule S in this base-rate case.

349. Ordering Paragraph 10 of the order on rehearing in Docket No. 46449 states, "[t]he regulatory treatment of any excess deferred taxes resulting from the reduction in the federal-income-tax rate will be addressed in SWEPCO's next base-rate case." The treatment of SWEPCO's excess deferred taxes has been addressed in this case.

III. Conclusions of Law

The Commission adopts the following conclusions of law.

1. SWEPCO is subject to PURA.

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

3. The Commission exercises regulatory authority over SWEPCO, and jurisdiction over the subject matter of this application under PURA §§ 14.001, 32.001, 32.101, 33.002, 33.051, and 36.001-112.

4. The Commission's jurisdiction to establish rates under PURA §§ 36.003-.004, 36.051-.065, 36.108(c), and 36.111 extends beyond the date a proposed rate is suspended.

5. SOAH has jurisdiction over matters related to the conduct of the hearing and the preparation of a proposal for decision in this docket, under PURA § 14.053 and Tex. Gov't. Code § 2003.049.

6. This docket was processed in accordance with the requirements of PURA and the Texas Administrative Procedure Act, Texas Government Code chapter 2001.

7. SWEPCO provided notice of its application in compliance with PURA § 36.103 and 16 TAC § 22.51(a).

8. Pursuant to PURA § 33.001, each municipality in SWEPCO's service area that has not ceded jurisdiction to the Commission has jurisdiction over SWEPCO's application, which seeks to change rates for the distribution services within each municipality.

9. Pursuant to PURA § 33.051, the Commission has jurisdiction over an appeal from a municipality's rate proceeding.

10. SWEPCO has the burden of proving that the rate change it is requesting is just and reasonable under PURA § 36.006.

11. In compliance with PURA § 36.051, SWEPCO's overall revenues approved in this proceeding permit SWEPCO a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.

12. Consistent with PURA § 36.053, the rates approved in this proceeding are based on original cost, less depreciation, of property used and useful to SWEPCO in providing service.

13. The rates approved in this proceeding are consistent with 16 TAC § 25.231(b)(1)(B), which states that depreciation expense based on original cost and computed on a straight-line basis as approved by the Commission shall be used; it also provides that other methods may be used when the Commission determines such depreciation methodology is a more equitable means of recovering the costs of plant.

14. The rates approved in this proceeding are consistent with 16 TAC § 25.231(c)(2)(A)(ii), which states that the reserve for depreciation is the accumulation of recognized allocations of original cost, representing the recovery of initial investment over the estimated useful life of the asset.

15. SWEPCO's short-term incentive compensation payments to collectively bargained employees should not be reduced to remove financially based short-term incentive compensation consistent with PURA § 14.006.

16. Upon completion of this base rate case under 16 TAC § 25.239(f), SWEPCO's TCRF should be set to zero.

17. The ROE and overall rate of return authorized in this proceeding are consistent with the requirements of PURA §§ 36.051 and 36.052.

18. The Commission has authority under PURA §§ 11.002, 14.001, 14.003, 14.154(a), 14.201, 36.003(a) to order SWEPCO to adopt the financial protections listed in findings of fact Nos. 108 and 109A.

19. Prudence is the exercise of that judgment and the choosing of one of that select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives available at the point in time such judgments is exercised or option is chosen. *Gulf States Util. Co. v. Public Util. Comm'n,* 841 S.W.2d 459, 476 (Tex. App—Austin 1992, writ denied).

20. There may be more than one prudent option within the range available to a utility in a given context. Any choice within the select range of reasonable options is prudent, and the Commission should not substitute its judgment for that of the utility. The reasonableness of an action or decision must be judged in light of the circumstances,

information, and available options existing at the time, without benefit of hindsight. Docket No. 40443, order on rehearing at 5 (citing *Nucor Steel v. Public Utility Commission of Texas,* 26 S.W.3d 742, 752 (Tex. App.—Austin 2000, pet. denied)).

21. A utility may demonstrate the prudence of its decision making through contemporaneous evidence. Alternatively, the utility may obtain an independent, retrospective analysis that demonstrates that a reasonable utility manager, having investigated all relevant factors and alternatives, as they existed at the time the decision was made, would have found the utility's actual decision to be a reasonably prudent course. *Gulf States,* 841 S.W.2d at 476.

22. The utility does not enjoy a presumption that the expenditures reflected in its books have been prudently incurred merely by opening the books to inspection. But while the ultimate burden of persuasion on the issue of prudence remains with the utility, its initial burden of production (to come forward with evidence) is shifted to opponents if the utility establishes a prima facie case of prudence. This is a "Commission-made" rule, intended "to aid in the trial of utility prudence reviews" and facilitate "efficient hearings," allowing the utility to establish prudence "by introducing evidence that is comprehensive, but short of proof of the prudence of every bolt, washer, pipe hanger, cable tray, I-beam, or concrete pour." *Entergy Gulf States, Inc. v. Public Util. Comm 'n,* 112 S.W.3d 208, 214-15, and n.5 (Tex. App.—Austin 2003, pet. denied).

23. The rate year is defined in 16 TAC § 25.5(101) as the 12-month period beginning with the first date that rates become effective.

24. The rates approved by this order are effective for consumption on and after March 18, 2021 in accordance with PURA § 36.211(b) and 16 TAC § 25.246(d)(1).

25. The Commission's cost of service rule permits, in accordance with 16 TAC § 25.231(c)(2)(F)(iii), post-test year adjustments for known and measurable decreases to test-year data under conditions that include a plant being removed from service, mothballed, sold, or removed from the electric utility's books prior to the rate year.

26. The Commission has discretion in accordance with 16 TAC § 25.3 to make exceptions to its substantive rules applicable to electric-service providers, including its cost-of-service rule, for good cause.

27. While the Commission's cost of service rule, 16 TAC § 25.231(b)(1)(B), generally requires that depreciation expense shall be computed on a straight-line basis, other methods may be used when it is determined that such depreciation methodology is a more equitable means of recovering the cost of the plant.

28. PURA § 36.064 requires SWEPCO to prove that: (1) its proposed self-insurance reserve coverage is in the public interest; (2) the plan, considering all costs, would be a lower cost alternative to purchasing commercial insurance; and (3) customers would receive the benefits of the savings.

29. For SWEPCO to establish under 16 TAC § 25.231(b)(1)(G) that its self-insurance plan is in the public interest, SWEPCO must present a cost benefit analysis performed by a qualified independent insurance consultant who demonstrates that, with consideration of all costs, self-insurance is a lower-cost alternative than commercial insurance and the customers will receive the benefits of the self-insurance plan. Further, the cost benefit analysis shall present a detailed analysis of the appropriate limits of self-insurance, an analysis of the appropriate annual accruals to build a reserve account for self-insurance, and the level at which further accruals should be decreased or terminated.

30. SWEPCO met its burden of proof under PURA § 36.064(b) and 16 TAC § 25.231(b)(1)(G) to show that its proposed self-insurance reserve would be in the public interest.

31. Affiliate expenses to be included in SWEPCO's rates must meet the standards articulated in PURA §§ 36.051 and 36.058 and in *Railroad Commission of Texas v. Rio Grande Valley Gas Co.,* 683 S.W.2d 783 (Tex. App.—Austin 1984, no writ).

32. Investor-owned utilities may include in rate base a reasonable allowance for cash working capital as determined by a lead-lag study conducted in accordance with 16 TAC § 25.231(c)(2)(B)(iii)(IV).

33. A lead-lag study in compliance with 16 TAC § 25.231(c)(2)(B)(iii)(IV) and (V) is performed to determine the reasonableness of a cash working capital allowance.

34. DELETED.

35. DELETED.

36. DELETED.

37. DELETED.

38. A transmission-voltage customer that submits an opt-out notice to the Commission is not required under 16 TAC § 25.173(j) to pay costs incurred by the utility to acquire renewable energy credits.

39. Utilities seeking recovery or municipalities seeking reimbursement of renewable energy credits have the burden to prove the reasonableness of such expenses by a preponderance of the evidence to include those amounts in customers' rates.

40. Except for charges by attorneys and consultants in excess of $550 per hour and the $2,500 cap on CARD's expenses in Docket No. 47141, the rate-case expenses SWEPCO is seeking to recover in this case for itself and CARD are recoverable pursuant to PURA § 36.061(b).

41. SWEPCO's rates, as approved in this proceeding, are just and reasonable in accordance with PURA § 36.003.

IV. Ordering Paragraphs

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

1. The proposal for decision, including findings of fact and conclusions of law is adopted to the extent provided in this Order.

2. SWEPCO's application is granted to the extent consistent with this Order.

3. The Commission grants SWEPCO a good cause exception under 16 TAC § 25.3 to make post-test year adjustments to its rate base to reflect that Dolet Hills, the Oxbow investment, and DHLC will cease to provide service to SWEPCO's customers when the plant retires on December 31, 2021.

4. SWEPCO shall implement and adhere to the financial protections listed in finding of fact nos. 108 and 109A. No later than 90 days from the date of this Order, SWEPCO shall have implemented, and be adhering to, all of those financial protections.

5. In its direct testimony in its next base-rate case, SWEPCO shall address why some of its customer classes, including the cotton gin class, the oilfield secondary class, and the public street and highway lighting class, historically are far below their relative rates of return produced by SWEPCO's CCOSS, and whether adjustments, other than gradualism, can and should be made to address this recurring situation.

6. In its direct testimony in its next base-rate case, SWEPCO shall address why customers can or should be allowed to migrate from class-to-class without experiencing a change in load or operations. In that testimony, SWEPCO should explain how it accounts for these future migrations through its adjusted billing determinants, and either justify its existing relatively open class structure or propose rate schedule revisions that more closely group similarly situated customers into rate schedules.

7. SWEPCO may recover its authorized rate-case expenses through its proposed rate case surcharge rider.

8. SWEPCO and CARD may seek to recover in a future proceeding any trailing rate-case expenses not already presented in their July 6, 2021 rate-case-expense reports for this case.

9. SWEPCO's TCRF and DCRF are set to zero at the conclusion of this base-rate case. The baseline values for SWEPCO's TCRF, DCRF, and generation cost recovery rider shall be developed and set during the compliance phase of this docket in *Compliance Tariff for Final Order in Docket No. 51415 (Application of Southwestern Electric Power Company for Authority to Change Rates),* Control No. 53046.

10. Notwithstanding findings of fact nos. 80-83, SWEPCO is authorized to establish a regulatory asset for the return that would be associated with inclusion of SWEPCO's stand-alone NOLC ADFIT in the calculation of rate base, as well as the net excess amortization of excess ADFIT in the calculation of the cost of service, with an effective date equal to that of the rates being implemented in this proceeding—March 18, 2021. SWEPCO will be eligible to request recovery of that regulatory asset once it receives an Internal Revenue Service determination that removal of the stand-alone NOLC ADFIT from the calculation of rate base constitutes a normalization violation. If the Internal

Revenue Service determines that such removal does not constitute a normalization violation, the regulatory asset will be written-off and not recovered from customers.

11. As part of its annual filing required under 16 TAC § 25.97(f), SWEPCO must include in its report information on each occurrence of an outage related to vegetation contact with utility infrastructure and identify the length of time since that line received vegetation management treatment. SWEPCO must also provide a list of every distribution line that has not received vegetation management treatment in the previous four years.

12. SWEPCO shall file tariffs consistent with this Order within 20 days of the date of this Order in Compliance Tariff for Final Order in Docket No. 51415 (Application of Southwestern Electric Power Company for Authority to Change Rates), Control No. 53046. No later than ten days after the date of the tariff filings, Commission Staff shall file its comments recommending approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to Commission Staff's recommendation shall be filed no later than 15 days after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter.

13. The tariff sheets shall be deemed approved and shall become effective on the expiration of 20 days from the date of filing, in the absence of written notification of modification or rejection by the Commission. If any sheets are modified or rejected, SWEPCO shall file proposed revisions of those sheets in accordance with the Commission's letter within ten days of the date of that letter, and the review procedure set out above shall apply to the revised sheets.

14. Copies of all tariff-related filings shall be served on all parties of record.

15. The Commission denies all other motions and any other requests for general or specific relief, if not expressly granted.

Signed at Austin, Texas the 14th **day of** January **2022.**

PUBLIC UTILITY COMMISSION OF TEXAS

PETER M. LAKE, CHAIRMAN

WILL MCADAMS, COMMISSIONER

JIMMY GLOTFELTY, COMMISSIONER

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Tex. R. Disc. Prof'l. Cond. 1.04

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As amended through February 20, 2024

Rule 1.04 - Fees

(a) A lawyer shall not enter into an arrangement for, charge, or collect an illegal fee or unconscionable fee. A fee is unconscionable if a competent lawyer could not form a reasonable belief that the fee is reasonable.

(b) Factors that may be considered in determining the reasonableness of a fee include, but not to the exclusion of other relevant factors, the following:

(1) the time and labor required, the novelty and difficulty of the questions involved, and the skill requisite to perform the legal service properly;

(2) the likelihood, if apparent to the client, that the acceptance of the particular employment will preclude other employment by the lawyer;

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(5) the time limitations imposed by the client or by the circumstances;

(6) the nature and length of the professional relationship with the client;

(7) the experience, reputation, and ability of the lawyer or lawyers performing the services; and

(8) whether the fee is fixed or contingent on results obtained or uncertainty of collection before the legal services have been rendered.

(c) When the lawyer has not regularly represented the client, the basis or rate of the fee shall be communicated to the client, preferably in writing, before or within a reasonable time after commencing the representation.

(d) A fee may be contingent on the outcome of the matter for which the service is rendered, except in a matter in which a contingent fee is prohibited by paragraph (c) or other law. A contingent fee agreement shall be in writing and shall state the method by which the fee is to be determined. If there is to be a differentiation in the percentage or percentages that shall accrue to the lawyer in the event of settlement, trial or appeal, the percentage for each shall be stated. The agreement shall state the litigation and other expenses to be deducted from the recovery, and whether such expenses are to be deducted before or after the contingent fee is calculated. Upon conclusion of a contingent fee matter, the lawyer shall provide the client with a written statement describing the outcome of the matter and, if there is a recovery, showing the remittance to the client and the method of its determination.

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lawyers who are not in the same firm may be made only if:

(1) the division is:

(i) in proportion to the professional services performed by each lawyer; or

(ii) made between lawyers who assume joint responsibility for the representation; and

(2) the client consents in writing to the terms of the arrangement prior to the time of the association or referral proposed, including

(i) the identity of all lawyers or law firms who will participate in the fee-sharing arrangement, and

(ii) whether fees will be divided based on the proportion of services performed or by lawyers agreeing to assume joint responsibility for the representation, and

(iii) the share of the fee that each lawyer or law firm will receive or, if the division is based on the proportion of services performed, the basis on which the division will be made; and

(3) the aggregate fee does not violate paragraph (a).

(g) Every agreement that allows a lawyer or law firm to associate other counsel in the representation of a person, or to refer the person to other counsel for such representation, and that results in such an association with or referral to a different law firm or a lawyer in such a different firm, shall be confirmed by an arrangement conforming to paragraph (f). Consent by a client or a prospective client without knowledge of the information specified in subparagraph (f)(2) does not constitute a

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person; and

(2) the reasonable and necessary expenses actually incurred on behalf of that person.

(h) Paragraph (f) of this rule does not apply to payment to a former partner or associate pursuant to a separation or retirement agreement, or to a lawyer referral program certified by the State Bar of Texas in accordance with the Texas Lawyer Referral Service Quality Act, Tex. Occ. Code 952.001 et seq., or any amendments or recodifications thereof.

Tex. Disc. R. Prof. Cond. 1.04

Comment:

1. A lawyer in good conscience should not charge or collect more than a reasonable fee, although he may charge less or no fee at all. The determination of the reasonableness of a fee, or of the range of reasonableness, can be a difficult question, and a standard of reasonableness is too vague and uncertain to be an appropriate standard in a disciplinary action. For this reason, paragraph (a) adopts, for disciplinary purposes only, a clearer standard: the lawyer is subject to discipline for an illegal fee or an unconscionable fee. Paragraph (a) defines an unconscionable fee in terms of the reasonableness of the fee but in a way to eliminate factual disputes as to the fees reasonableness. The Rules unconscionable standard, however, does not preclude use of the reasonableness standard of paragraph (b) in other settings.

Basis or Rate of Fee

2. When the lawyer has regularly represented a client, they ordinarily will have evolved an understanding concerning the basis or rate of the fee. If, however, the basis or rate of fee being charged to a regularly represented client differs from the understanding that has evolved, the lawyer should so advise the client. In a new client-lawyer relationship, an understanding as

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order to identify the factors that may be taken into account in finally fixing the fee. When developments occur during the representation that render an earlier estimate substantially inaccurate, a revised estimate should be provided to the client. A written statement concerning the fee reduces the possibility of misunderstanding, and when the lawyer has not regularly represented the client it is preferable for the basis or rate of the fee to be communicated to the client in writing. Furnishing the client with a simple memorandum or a copy of the lawyer's customary fee schedule is sufficient if the basis or rate of the fee is set forth. In the case of a contingent fee, a written agreement is mandatory.

Types of Fees

3. Historically lawyers have determined what fees to charge by a variety of methods. Commonly employed are percentage fees and contingent fees (which may vary in accordance with the amount at stake or recovered), hourly rates, and flat fee arrangements, or combinations thereof.

4. The determination of a proper fee requires consideration of the interests of both client and lawyer. The determination of reasonableness requires consideration of all relevant circumstances, including those stated in paragraph (b). Obviously, in a particular situation not all of the factors listed in paragraph (b) may be relevant and factors not listed could be relevant. The fees of a lawyer will vary according to many factors, including the time required, the lawyer's experience, ability and reputation, the nature of the employment, the responsibility involved, and the results obtained.

5. When there is a doubt whether a particular fee arrangement is consistent with the client's best interest, the lawyer should discuss with the client alternative bases for the fee and explain their implications.

6. Once a fee arrangement is agreed to, a lawyer should not handle the matter so as to further the lawyer's financial interests to the detriment of

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7. Two principal circumstances combine to make it difficult to determine whether a particular fee is unconscionable within the disciplinary test provided by paragraph (a) of this Rule. The first is the subjectivity of a number of the factors relied on to determine the reasonableness of fees under paragraph (b). Because those factors do not permit more than an approximation of a range of fees that might be found reasonable in any given case, there is a corresponding degree of uncertainty in determining whether a given fee is unconscionable. Secondly, fee arrangements normally are made at the outset of representation, a time when many uncertainties and contingencies exist, while claims of unconscionability are made in hindsight when the contingencies have been resolved. The unconscionability standard adopts that difference in perspective and requires that a lawyer be given the benefit of any such uncertainties for disciplinary purposes only. Except in very unusual situations, therefore, the circumstances at the time a fee arrangement is made should control in determining a question of unconscionability.

8. Two factors in otherwise borderline cases might indicate a fee may be unconscionable. The first is overreaching by a lawyer, particularly of a client who was unusually susceptible to such overreaching. The second is a failure of the lawyer to give at the outset a clear and accurate explanation of how a fee was to be calculated. For example, a fee arrangement negotiated at arms length with an experienced business client would rarely be subject to question. On the other hand, a fee arrangement with an uneducated or unsophisticated individual having no prior experience in such matters should be more carefully scrutinized for overreaching. While the fact that a client was at a marked disadvantage in bargaining with a lawyer over fees will not make a fee unconscionable, application of the disciplinary test may require some consideration of the personal circumstances of the individuals involved.

Fees in Family Law Matters

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assets obtained for client. See also Rule 1.08(h). In certain family law matters, such as child custody and adoption, no res is created to fund a fee. Because of the human relationships involved and the unique character of the proceedings, contingent fee arrangements in domestic relations cases are rarely justified.

Division of Fees

10. A division of fees is a single billing to a client covering the fee of two or more lawyers who are not in the same firm. A division of fees facilitates association of more than one lawyer in a matter in which neither alone could serve the client as well, and most often is used when the fee is contingent and the division is between a referring or associating lawyer initially retained by the client and a trial specialist, but it applies in all cases in which two or more lawyers are representing a single client in the same matter, and without regard to whether litigation is involved. Paragraph (f) permits the lawyers to divide a fee either on the basis of the proportion of services they render or if each lawyer assumes joint responsibility for the representation.

11. Contingent fee agreements must be in a writing signed by the client and must otherwise comply with paragraph (d) of this Rule.

12. A division of a fee based on the proportion of services rendered by two or more lawyers contemplates that each lawyer is performing substantial legal services on behalf of the client with respect to the matter. In particular, it requires that each lawyer who participates in the fee have performed services beyond those involved in initially seeking to acquire and being engaged by the client. There must be a reasonable correlation between the amount or value of services rendered and responsibility assumed, and the share of the fee to be received. However, if each participating lawyer performs substantial legal services on behalf of the client, the agreed division should control even though the division is not directly proportional

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arrangement must include the basis by which the division will be made.

13. Joint responsibility for the representation entails ethical and perhaps financial responsibility for the representation. The ethical responsibility assumed requires that a referring or associating lawyer make reasonable efforts to assure adequacy of representation and to provide adequate client communication. Adequacy of representation requires that the referring or associating lawyer conduct a reasonable investigation of the client's legal matter and refer the matter to a lawyer whom the referring or associating lawyer reasonably believes is competent to handle it. See Rule 1.01. Adequate attorney-client communication requires that a referring or associating lawyer monitor the matter throughout the representation and ensure that the client is informed of those matters that come to that lawyer's attention and that a reasonable lawyer would believe the client should be aware. See Rule 1.03. Attending all depositions and hearings, or requiring that copies of all pleadings and correspondence be provided a referring or associating lawyer, is not necessary in order to meet the monitoring requirement proposed by this rule. These types of activities may increase the transactional costs, which ultimately the client will bear, and unless some benefit will be derived by the client, they should be avoided. The monitoring requirement is only that the referring lawyer be reasonably informed of the matter, respond to client questions, and assist the handling lawyer when necessary. Any referral or association of other counsel should be made based solely on the client's best interest.

14. In the aggregate, the minimum activities that must be undertaken by referring or associating lawyers pursuant to an arrangement for a division of fees are substantially greater than those assumed by a lawyer who forwarded a matter to other counsel, undertook no ongoing obligations with respect to it, and yet received a portion of the handling lawyer's fee once the matter was concluded, as was permitted under the prior version of this rule. Whether such activities, or any additional activities that a lawyer might agree to undertake, suffice to make one lawyer participating in such

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15. A client must consent in writing to the terms of the arrangement prior to the time of the association or referral proposed. For this consent to be effective, the client must have been advised of at least the key features of that arrangement. Those essential terms, which are specified in subparagraph (f)(2), are

1) The identity of all lawyers or law firms who will participate in the fee-sharing agreement,

(2) Whether fees will be divided based on the proportion of services performed or by lawyers agreeing to assume joint responsibility for the representation, and

(3) The share of the fee that each lawyer or law firm will receive or the basis on which the division will be made if the division is based on proportion of service performed. Consent by a client or prospective client to the referral to or association of other counsel, made prior to any actual such referral or association but without knowledge of the information specified in subparagraph (f)(2), does not constitute sufficient client confirmation within the meaning of this rule. The referring or associating lawyer or any other lawyer who employs another lawyer to assist in the representation has the primary duty to ensure full disclosure and compliance with this rule.

16. Paragraph (g) facilitates the enforcement of the requirements of paragraph (f). It does so by providing that agreements that authorize an attorney either to refer a person's case to another lawyer, or to associate other counsel in the handling of a client's case, and that actually result in such a referral or association with counsel in a different law firm from the one entering into the agreement, must be confirmed by an arrangement between the person and the lawyers involved that conforms to paragraph (f). As noted there, that arrangement must be presented to and agreed to by the person before the referral or association between the lawyers involved

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referring that person's matter to other counsel. Paragraph (g) does provide, however, for recovery in quantum meruit in instances where its requirements are not met. See subparagraphs (g)(1) and (g)(2).

17. What should be done with any otherwise agreed-to fee that is forfeited in whole or in part due to a lawyer's failure to comply with paragraph (g) is not resolved by these rules.

18. Subparagraph (f)(3) requires that the aggregate fee charged to clients in connection with a given matter by all of the lawyers involved meet the standards of paragraph (a)-that is, not be unconscionable.

Fee Disputes and Determinations

19. If a procedure has been established for resolution of fee disputes, such as an arbitration or mediation procedure established by a bar association, the lawyer should conscientiously consider submitting to it. Law may prescribe a procedure for determining a lawyer's fee, for example, in representation of an executor or administrator, or when a class or a person is entitled to recover a reasonable attorney's fee as part of the measure of damages. All involved lawyers should comply with any prescribed procedures.

Previous Section
Rule 1.03 - Communication

Next Section
Rule 1.05 - Confidentiality of Information

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§ 36.061. Allowance of Certain Expenses, TX UTIL § 36.061

Vernon's Texas Statutes and Codes Annotated
Utilities Code (Refs & Annos)
Title 2. Public Utility Regulatory Act (Refs & Annos)
Subtitle B. Electric Utilities (Refs & Annos)
Chapter 36. Rates (Refs & Annos)
Subchapter B. Computation of Rates

V.T.C.A., Utilities Code § 36.061

§ 36.061. Allowance of Certain Expenses

Effective: June 14, 2013
Currentness

(a) The regulatory authority may not allow as a cost or expense for ratemaking purposes:

(1) an expenditure for legislative advocacy; or

(2) an expenditure described by Section 32.104 that the regulatory authority determines to be not in the public interest.

(b) The regulatory authority may allow as a cost or expense:

(1) reasonable charitable or civic contributions not to exceed the amount approved by the regulatory authority; and

(2) reasonable costs of participating in a proceeding under this title not to exceed the amount approved by the regulatory authority.

(c) An electric utility located in a portion of this state not subject to retail competition may establish a bill payment assistance program for a customer who is a military veteran who a medical doctor certifies has a significantly decreased ability to regulate the individual's body temperature because of severe burns received in combat. A regulatory authority shall allow as a cost or expense a cost or expense of the bill payment assistance program. The electric utility is entitled to:

(1) fully recover all costs and expenses related to the bill payment assistance program;

(2) defer each cost or expense related to the bill payment assistance program not explicitly included in base rates; and

(3) apply carrying charges at the utility's weighted average cost of capital to the extent related to the bill payment assistance program.

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§ 36.061. Allowance of Certain Expenses, TX UTIL § 36.061

Credits

Acts 1997, 75th Leg., ch. 166, § 1, eff. Sept. 1, 1997. Amended by Acts 2013, 83rd Leg., ch. 597 (S.B. 981), § 1, eff. June 14, 2013.

Notes of Decisions (16)

V. T. C. A., Utilities Code § 36.061, TX UTIL § 36.061
Current through the end of the 2017 Regular and First Called Sessions of the 85th Legislature

End of Document

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2024 Billing Rate & Associate Salary Survey (BRASS) Initial Release

The **Billing Rate & Associate Salary Survey (BRASS)** is recognized as the industry leader in providing law firms with comprehensive benchmarking information across a broad spectrum of metrics.

The Survey maintains a strong and consistent participation base with over 250 of the largest national law firms participating.

Participants choose which metrics are most important to their Firm and our Data Form can be tailored to meet those needs - reducing the time investment to participate.

The Law Firm Survey Staff is committed to providing law firms with exceptional client service and meaningful insights into their business, resulting in a better understanding of their market position.

Survey Staff contact info

Please contact a Survey Staff member with any questions at (703) 918-3077 or via email at *us_pwc_law_firm_survey_team@pwc.com*

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Report/Product offerings

The Revenue Management Report (RMR) provides a wide range of metrics on the four core areas of revenue management.

The Talent Management Report (TMR) is a two-pronged Report that contains information on attorney & non-attorney compensation as well as diversity metrics.

The Partner Management Report (PMR) includes compensation and capital balance metrics for both groups of Partners.

The **Revenue360 Dashboard** supplements the RMR to allow multiple users at the Firm to interactively filter between both historical and current year benchmarks across multiple comparison groups.

Complimentary review of results

Discussions and reviews can be scheduled with the Survey Staff to assist participants in their understanding of the Survey results.

Timing

Data Form Due Date: April 19th

Distribution of Results: Early June

Highlights

Non-Attorney Timekeeper Classifications are included in the Revenue360 Tableau Dashboard.

Each Firm will receive a complimentary Talent Management Report (TMR). This Report style not only provides insights into the compensation levels of the Associates, but more importantly, links bonuses received to the corresponding utilization levels by class year.

Participants have the option to submit and receive international office metrics. Any Firm that submits an office in local currency, will receive a complimentary Local Currency Report.

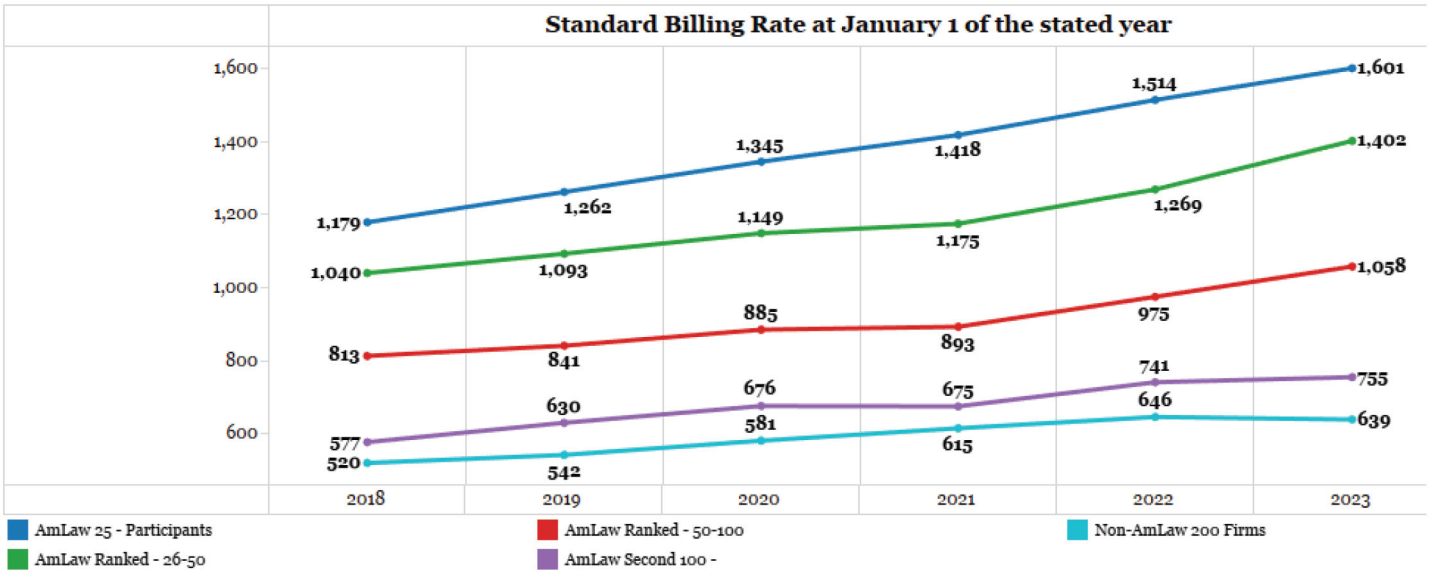
The Revenue360 Performance Analytics Dashboard file is once again included in the base participation fee.

Pricing has been modified to be more cost-effective for small to mid-size firms.

www.pwc.com/us/lfsurveys

2024 Billing Rate & Associate Salary Survey

Timekeeper Class: EQ Partners
Group(s): AmLaw 25 - Participants (20 mbrs), AmLaw Ranked - 26-50 (20 mbrs), AmLaw Ranked - 50-100 (38 mbrs) and 2 more



Group Name		2018	2019	2020	2021	2022	2023
AmLaw 25 - Participants	1st Qtr	1,303	1,347	1,443	1,512	1,618	1,750
	Median	1,179	1,262	1,345	1,418	1,514	1,601
	3rd Qtr	1,065	1,126	1,266	1,319	1,382	1,471
AmLaw Ranked - 26-50	1st Qtr	1,064	1,120	1,187	1,261	1,347	1,437
	Median	1,040	1,093	1,149	1,175	1,269	1,402
	3rd Qtr	911	944	986	1,064	1,154	1,221
AmLaw Ranked - 50-100	1st Qtr	866	918	958	967	1,052	1,100
	Median	813	841	885	893	975	1,058
	3rd Qtr	719	719	756	775	820	896
AmLaw Second 100 -	1st Qtr	851	920	994	999	1,019	1,075
	Median	577	630	676	675	741	755
	3rd Qtr	531	554	571	583	618	661
Non-AmLaw 200 Firms	1st Qtr	676	689	735	813	797	830
	Median	520	542	581	615	646	639
	3rd Qtr	457	473	506	532	515	538

Sample reports

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Participants reported that our one-on-one Firm reviews of their results was an added value to participation.

Our Dashboard offering and tailored webcasts to review trends were also key factors in their overall satisfaction.

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Largest law firms charge nearly $1,000 an hour, report finds

The 4.8% rate increase through Q3 2023 was more than triple the bump last year among the Am Law 100, according to a Brightflag report.

Published Dec. 11, 2023

Lyle Moran
Reporter

Binary code abstract background with a stack of $100 bills Viorika via Getty Images

The top 100 U.S. law firms charged clients an average of $961 an hour in the first nine months of 2023, a recent report found.

The average blended rate billed by Am Law 100 firms is a 4.8% increase from the $917 an hour those firms charged throughout 2022, according to the hourly rates analysis from e-billing and matter management platform Brightflag.

"In 2022, the blended rate increased by 1.5% when compared with 2021," the report said. "This means that the increase experienced in 2023 was over three times higher than the increase of the preceding year."

Driver of increase

The blended rate was calculated by dividing the total amount that outside counsel billed for work across timekeepers by the total hours billed.

The analysis was based on Brightflag's database of billions of dollars of outside counsel spend, and it used billed rates as opposed to rack rates or requested rates.

The report said an increase in blended rates can stem from a rise in the rates charged by individual fee earners or an uptick in billing by fee earners that charge higher rates.

"Brightflag's data on the average rates charged per fee earner type suggests that the key driver of increases in 2023 was a rise in individual fee earner rates, as opposed to a drastic change in matter resourcing," the report said.

Different firm categories

Perhaps unsurprisingly, timekeepers at firms ranked higher in the Am Law 100 rankings charge more than firms lower in the list.

One example cited is that partners at the top 25 firms charge an average of $1,433 an hour, which is almost double the $729 average hourly rate charged by partners at firms 51-75 in the rankings.

Associates at the larger firms also charge more than their peers lower in the rankings.

For example, associates at the top 25 firms charge $951 an hour on average compared to associates at firms ranked 51-75 billing $617 an hour.

"This demonstrates the significant savings that can be made by moving work from the highest-cost firms to smaller, more cost-efficient firms," the report said.

Geography

The Brightflag analysis also found that partners at the Am Law 100 firms based in larger metropolitan areas charge more than their peers in other locations.

Partners in New York lead the way by a significant margin, with those attorneys charging an average of $1,562 an hour.

The second-highest hourly rates are charged by partners in the Los Angeles area, with those lawyers billing $1,192 an hour on average.

At the other end of the spectrum, partners in the Kansas City area charge $764 an hour on average.

"Brightflag's data shows that even within the top 100 U.S. firms, partner rates in the largest cities are 40-50% higher than those in smaller cities," the report said. "Therefore, working with outside counsel in smaller cities can have a major impact on outside spend, even if you continue to work with top firms."

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Law Firms See Revenue Growth Amid Soaring Billing Rates

By **Aebra Coe**

Law360 (November 15, 2023, 4:22 PM EST) -- As of the end of the third quarter of 2023, U.S. law firms had increased their revenues, on average, by 4.6% year-over-year as a result of "the highest growth in billing rates we've seen," according to a new report from Wells Fargo Legal Specialty Group.

Law firms brought in more revenue even as demand continued to lag, increasing just 0.2% as of the end of the third quarter across the cohort of more than 120 law firms surveyed by Wells Fargo, according to the report released Wednesday.

The rise in revenue was largely fueled by a 7.9% year-over-year increase in billing rates among all the law firms, and an 8.2% increase among the respondents ranked in the top 100 in the U.S. by revenue, the report said.

With the jump in revenue, law firms also posted an increase in net income and profits per partner as of the end of September, with net income on average increasing by 2.7% and profits per partner by 1%. However, those results were buttressed by strong numbers reported by the largest law firms, with smaller firms faring less well.

Among the top 50 law firms by revenue, net income was up 5.2%, among the top 100 firms it was up 3.7%, and among the firms ranked in the second 100 by revenue, net income actually fell by 3.9%.

For those that performed well on net income, one major contributor was an industrywide reining in of expense growth, according to the report. Expense growth slowed to 5.6% at the end of the third quarter, down from 6.2% midyear and 12.8% this time last year.

Alongside the differences in net income, law firms' expense growth also varied based on firm size, with the largest firms seeing smaller upticks than those among the second 50 largest and second 100 largest by revenue.

One part of the expense equation for firms is lawyer headcount, which continued to increase during the third quarter, although at 3.5%, the pace was slightly slower than in the previous year.

Because of the flat demand and increases in headcount, lawyer productivity among the cohort remained low, with an average annualized pace of 1,540 billable hours per lawyer, maintaining levels logged midyear that are well below 2018, 2019 and 2021 figures, the report found.

Of the more than 120 law firms surveyed by Wells Fargo for the report, 65 were among the 100 largest in the U.S. by revenue, 30 were among the second 100, and the remainder represented regional law firms, according to the bank's legal specialty group.

--Editing by Linda Voorhis.

Correction: This article previously misstated the Wells Fargo survey methodology. The error has been corrected.

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Top Law Firms' Revenue Rose 6% on Higher Rates, Wells Fargo Says

By Roy Strom

- Wells Fargo survey is first to report annual results for Big Law firms
- Bank finds firms returned to strong growth despite slow deals market

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Top Law Firms' Revenue Rose 6% on Higher Rates, Wells Fargo Says

By Roy Strom 2024-01-30T11:04:52000-05:00

Wells Fargo survey is first to report annual results for Big Law firms

Bank finds firms returned to strong growth despite slow deals market

The country's 100 largest law firms posted revenue growth of 6% in 2023 as higher prices for lawyers' time and a slight increase in demand more than made up for a broad slowdown in deals, a Wells Fargo & Co. survey found.

The average profits per equity partner at the 100 firms increased more than 5% from 2022, Wells Fargo said.

The revenue gains last year were mostly driven by higher billing rates. The 100 largest law firms raised their hourly rates at a record, nearly 9%, in 2023, Wells Fargo said. Demand was up by less than 1%.

The survey by the bank's legal specialty group is the first of three major year-end financial barometers for the Big Law market. Reports from Citi Private Bank and The American Lawyer, which are yet to be released, are expected show a significantly healthier year for Big Law compared to 2022, which was a relatively rough stretch for lawyers.

While the mergers and acquisitions and capital markets transactions that typically power Big Law results failed to register significant growth in 2023, Wells Fargo said there was "strength" in counter-cyclical practices such as litigation, restructuring, antitrust, and intellectual property.

Law firms have even rosier expectations for 2024, said Owen Burman, managing director of the Wells Fargo legal specialty group. They anticipate demand—total hours billed—rising by around 3%, he said.

"We think that's achievable, because the drivers from 2023 are still in place," Burman said. "Firms are still seeing good demand growth in restructuring and other counter-cyclical practices. But at the same time, we have a much more likely scenario of transaction markets coming back."

Firms have some wind in their sails as 2024 begins. Inventories, or bills waiting to be collected, grew nearly 11% at the 100 largest firms, the survey said.

"There is a belief that all facets of the market should be showing some significant improvement this year versus 2023," Burman said. "We see high single digit revenue growth for the industry in 2024. So it's a pretty good outlook."

Wells Fargo surveyed more than 130 law firms, including 70 of the 100 largest by revenue. Another 35 that were surveyed ranked between the 100th and 200th largest.

Firms have struggled to tame expenses in recent years, driven by associate salary increases, technology costs, and inflation. But they made some progress in 2023, with expenses up only 6% compared to 8% in 2022, Wells Fargo said.

Big Firms have also tried to tame bloated payrolls resulting from fewer associates than normal leaving firms. With low attrition, lawyer headcount at the largest firms rose 3% in 2023, down from 6% growth in 2022.

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