TEXAS COURT OF APPEALS, THIRD DISTRICT, AT AUSTIN

NO. 03-08-00577-CV

Appellant, The City of El Paso// Cross-Appellant, El Paso Electric Company

v.

Appellee, Public Utility Commission of Texas//
Cross-Appellees, El Paso Electric Company and The City of El Paso

FROM THE DISTRICT COURT OF TRAVIS COUNTY, 126TH JUDICIAL DISTRICT
D-1-GV-04-002026, HONORABLE LORA J. LIVINGSTON, JUDGE PRESIDING

O P I N I O N

El Paso Electric Company (EPE) and the City of El Paso (City) sued for judicial review of a final order in a contested case, a fuel-reconciliation proceeding EPE had initiated before the Public Utility Commission (Commission) in which the City had intervened. The district court affirmed the Commission's order in full. Both the City and EPE have appealed. We will affirm the district court's judgment.

BACKGROUND

EPE is an investor-owned electric utility that provides generation, transmission, and distribution service to retail and wholesale customers in west Texas, southern New Mexico, and California. Because the Texas Legislature thus far has not extended retail competition to EPE's service territory within this state, *see* Tex. Util. Code Ann. § 39.402 (West 2007),[1] the Commission has continued to set EPE's retail electric service rates under traditional cost-of-service rate-making principles. *See generally id.* §§ 36.001-.406 (West 2007 & Supp. 2010). Under these familiar principles, simply described, the Commission sets a utility's retail electric service rates so as to ensure that revenues are sufficient to cover the utility's projected reasonable and necessary future operating expenses, plus provide a reasonable rate of return on the utility's invested capital. The rates operate only prospectively, and the utility generally bears the risk that its actual operating expenses will exceed the projections incorporated into the rate—and its retail customers the corresponding risk that rates will "over-charge" relative to the utility's actual operating expenses—until a new rate-making proceeding can be conducted. However, with regard to the sometimes-volatile expenses utilities incur on fuel to generate power for sale or in purchasing power at wholesale for resale (the latter are known as "purchased-power expenses"), there is greater flexibility in adjusting rates to account for deviations between projections and actual expenses. The component of a utility's rates that covers these types of expenses—known as the "fuel factor," as distinguished from "base rates"—is essentially an interim or temporary rate subject to both periodic adjustment and retrospective true-up proceedings to "reconcile" revenues and actual expenses through refunds or surcharges to customers. *See, e.g.*, *Entergy Gulf States, Inc. v. Public Util. Comm'n of Tex.*, 173 S.W.3d 199, 206 (Tex. App.—Austin 2005, pet. denied).

EPE's most recent rate-making proceeding had been concluded by a 1995 agreed order and stipulation (1995 Stipulation/Agreed Order) under which the utility's base rates were

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[1] Except where there has been a material intervening substantive change, we cite the current versions of statutes and rules for convenience.

frozen until August 2005, the utility was prohibited from circumventing the freeze by shifting costs from base rates to reconcilable fuel costs, and its recovery of fuel costs was to be governed by the version of the Commission's "fuel rule" that was in effect as of July 1, 1995. *See* 16 Tex. Admin. Code § 23.23 (1995), *repealed by* 24 Tex. Reg. 4998 (1999) (hereinafter "Former Fuel Rule") (current version at 16 Tex. Admin. Code § 25.236 (2010)). In 2002, EPE initiated a proceeding to reconcile its eligible fuel expenses and revenues from its provision of service in Texas between January 1, 1999, and December 31, 2001 (the "reconciliation period"). EPE claimed that it had incurred a total of approximately $277 million in eligible fuel expenses in providing its electric service in Texas during the reconciliation period. The City and several other parties intervened. The Commission referred the matter to the State Office of Administrative Hearings for a contested-case hearing before a pair of administrative law judges (ALJs).

The central disputed issues relevant to this appeal concern the proper calculation of EPE's eligible fuel expenses in light of three sets of requirements under the 1995 Stipulation/Agreed Order and the Former Fuel Rule.

Capacity costs

Included in the fuel expenses EPE claimed were approximately $147 million in purchased-power expenses. The Commission staff, the City, and other intervenors argued that a portion of these expenses had actually included "capacity" charges that were not recoverable under the 1995 Stipulation/Agreed Order or the Former Fuel Rule. Although there is some debate regarding the precise nature of a "capacity" charge or how it can be identified, as we will explain below, in general the term has referred to a charge that recovers fixed costs of the wholesale seller in making assets available to generate power, as distinguished from "energy" charges that recover variable costs (e.g., fuel) incurred by the seller in generating the power itself. *See City of El Paso v. El Paso Elec. Co.*, 851 S.W.2d 896, 898 (Tex. App.—Austin 1993, writ denied) ("The term 'capacity costs' refers to one element of the price charged by a seller of electric power—an element that represents the seller's fixed costs in generating the power. (Another element, denominated 'energy charges,' represents the seller's variable costs in generating the power—the cost of fuel, for example)."); *Gulf States Utils. v. Public Util. Comm'n of Tex.*, 841 S.W.2d 459, 461 (Tex. App.—Austin 1992, writ denied) (describing capacity costs generally as "costs associated with providing the capability to deliver energy (primarily the capital costs of facilities)"). Accordingly, capacity costs have been considered to be among the fixed costs associated with generation assets that, in theory, are collected through base rates rather than the fuel factor. Preventing what in concept would be a double-recovery of these fixed costs through both base rates and fuel reconciliations, the Former Fuel Rule explicitly barred utilities from recovering "demand or capacity costs" as part of "eligible fuel expenses." *See* Former Fuel Rule § 23.23(b)(2)(B)(iv). In addition to relying on this exclusion for "demand or capacity costs," parties opposing EPE's claim for purchased-power expenses argued that EPE's inclusion of capacity costs attempted to shift base-rate costs to fuel costs in violation of the 1995 Stipulation/Agreed Order.

Historically, wholesale purchased-power contracts had identified separately stated "capacity" or "demand" and "energy" charges—the former generally priced by megawatt (MW) of capacity guaranteed, the latter priced by megawatt hour (MWh) of energy the purchaser actually takes. However, the deregulation of the wholesale electric markets in the 1990s had brought greater variety in the pricing terms under such contracts, which in turn had raised issues regarding whether contracts that did not identify or contain explicit "capacity" charges might nonetheless represent the sale of capacity. In a prior fuel-reconciliation proceeding involving another utility, Entergy Gulf States, the Commission had determined that it could look beyond the face of what were facially "energy-only" wholesale purchased-power contracts, ascertained that the conveyed "energy" in fact included "embedded" capacity, and disallowed recovery of a portion of the utility's claimed purchased-power expenses on that basis. *See Entergy Gulf States, Inc.*, 173 S.W.3d at 211. In determining that the Entergy contracts conveyed capacity, the Commission relied on evidence to the effect that Entergy had deliberately negotiated "energy-only" pricing terms to disguise capacity charges, as well as characteristics of the transactions that it regarded as consistent with capacity purchases. *See id.* These characteristics, in the Commission's view, included the fact that the utility made block purchases of power that provided the "capacity benefits" of "system-wide reliability and firmness of supply." *See id*. In the absence of an explicit capacity charge, the Commission "imputed" a value for the capacity sold equal to twenty-four percent of the contract price and deducted that amount from Entergy's eligible fuel expenses. *See id.* This Court upheld the Commission's treatment of capacity costs against challenges that it violated the fuel rule and was not supported by substantial evidence. *See id.* at 209-12.

In the present proceeding, following the hearing on EPE's petition, the ALJs issued a proposal for decision (PFD) in which they reasoned, based on what they perceived to be the Commission's rationale in the *Entergy* case, that a wholesale power purchase contains a capacity charge whenever (1) "the purchased power's cost is above the marginal energy cost for generation" (in the view that the difference would necessarily reflect the seller's fixed costs of generation) (2) "to the extent it is used to provide energy for a system's base load or reserve requirements." The ALJs found that EPE made purchases meeting these criteria in 1999, 2000, and 2001. Additionally, the ALJs found that a purchased-power contract between EPE and Southwestern Public Service Company (SPS) covering the year 2000 contained language that, while not containing a discrete charge for capacity, nonetheless reflected the conveyance of capacity. Similar to their methodology for identifying capacity costs in purchased-power contracts, the ALJs recommended that the imputed capacity costs in the contracts be calculated as the positive difference between EPE's purchased-power cost and its marginal cost of generation at its least efficient generating unit, which yielded a total-company disallowance of $30.5 million.

After reviewing this PFD and a supplement, the Commission requested additional briefing as to how it should identify and quantify embedded capacity costs in purchased-power contracts. The parties, as well as several amici, submitted briefing on that question. The Commission ultimately reaffirmed "the concept that power contracts that do not contain an explicitly identified and priced capacity component may nevertheless contain capacity costs."[2] However, concluding that the briefing "provided multiple and sometimes inconsistent approaches," and "demonstrated that there is not a single understanding of the concept of capacity," the Commission ultimately eschewed attempting a "comprehensive solution in this docket."[3] It instead confined

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[2] The Commission subsequently applied the same concept in the final fuel reconciliation of AEP Texas Central Company. *See AEP Tex. Cent. Co. v. Public Util. Comm'n of Tex.*, 286 S.W.3d 450, 471 (Tex. App.—Corpus Christi 2008, pet. denied).

[3] After this case was decided, the Commission initiated a rule-making proceeding to establish a methodology for identifying and quantifying imputed capacity costs. *See Entergy Gulf*

its inquiry to whether the particular EPE purchased-power contracts at issue represented sales of capacity.

The Commission rejected the ALJs' proposals to identify and value embedded capacity purchases based on an excess of the utility's purchased-power costs over its marginal costs of generation, reasoning that such a difference might be explained by circumstances other than payment for capacity or other fixed-cost recovery. Instead, the Commission looked first to the specific language and pricing structure of the contracts, concluding that "[c]apacity costs may be found in contracts without an explicit capacity charge when contract language indicates that capacity or demand is part of the purchase." The Commission found that one of EPE's purchased-power contracts contained such language—the 2000 contract with SPS. The Commission further concluded, similar to the analysis in *Entergy*, that "[t]his conclusion is bolstered if the contracts are made in advance and entered into on a long-term basis as part of annual planning to fulfill obvious peaking needs and satisfy reliability," and found that the SPS 2000 contract met those criteria. Under this contract, the Commission found, EPE had agreed to make block purchases of 50 kW of energy per month for twelve months, with an additional 50 kW per month for the months of June through October (a total of 850,000 kW annually), "to supply [its] base load generation needs." Furthermore, rejecting an argument advanced by EPE, the Commission found that the conveyance of a "dispatch right"—simply described, the buyer's discretion to determine when or if it wants to take power and how much—"is only one indicator that a power purchase has a capacity component" and that even "without a separately priced or labeled capacity element or dispatch rights in the

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States, Inc. v. Public Util. Comm'n of Tex., 173 S.W.3d 199, 212 (Tex. App.—Austin 2005, pet. denied). However, no rule was adopted at that time.

contracts," the contracts may have embedded capacity costs "if the purchases are intended to ensure reliability to the base load and cost more than the utility's marginal fuel generation costs."

As for how these embedded capacity costs should be valued, the Commission found that it was "reasonable" to use a proxy derived from the Western Systems Power Pool (WSPP) capacity-charge price cap of $7.32/kilowatt-month, an "amount . . . based upon the fixed costs of the WSPP's member units and . . . representative of the actual market cost for capacity during the reconciliation period." Multiplying that proxy charge times EPE's monthly power purchases yielded a total capacity disallowance of approximately $6.2 million from total company purchased-power expenses.

Special circumstances

In addition to arguing that none of the disputed purchased-power contracts contained capacity costs, EPE alternatively made a "special-circumstances" request to recover those costs through fuel charges. The Former Fuel Rule permitted a utility to recover demand or capacity costs otherwise excluded from eligible fuel expenses if the Commission determined that such treatment was "justified by special circumstances." *See* Former Fuel Rule § 23.23(b)(2)(B)(v). "In determining whether special circumstances exist," the rule provided that:

> the commission shall consider, in addition to the other factors developed in the record of the reconciliation proceeding, whether the fuel expense or transaction giving rise to the ineligible fuel expense resulted in, or is reasonably expected to result in, increased reliability of supply or lower fuel expenses than would otherwise be the case, and that benefits received or expected to be received by ratepayers exceed the costs that ratepayers otherwise would have paid or otherwise would reasonably expect to pay.

Id. The Commission failed to find special circumstances and did not grant EPE's request that it be permitted to recover any imputed capacity charges on that basis.

Off-system sales

Under the 1995 Stipulation/Agreed Order, EPE was required to apply a portion of the margins it earned (i.e., revenues less expenses) from "off-system" sales (wholesale sales to entities that are not native-load customers[4]) as a credit against the fuel costs allocated to Texas retail customers.[5] Consequently, the higher EPE's calculated margins were on its off-system sales (whether as a function of higher revenues, lower expenses, or both), the larger the credits against EPE's fuel costs, and the lower the eligible fuel costs that the utility could recover from its Texas retail customers.

Under a long-term contract it executed in the 1980s, EPE had agreed to sell the Imperial Irrigation District (IID) in California 50 MW of contingent capacity (i.e., depending on availability) with energy, to be served from EPE's total system resources. In return, IID agreed to pay EPE a demand charge, and a charge for energy equal to EPE's average system production costs plus a margin of $0.00236/kilowatt-hour. In its reconciliation petition, EPE calculated its margins

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[4] I.e., the retail and wholesale customers to whom a utility is required to provide service. *See Entergy Gulf States, Inc.*, 173 S.W.3d at 204 n.3; *see also* 18 C.F.R. § 33.3(d)(4)(i) (2010) (Federal Energy Regulatory Commission, Regulations under the Federal Power Act) ("Native load commitments are commitments to serve wholesale and retail power customers on whose behalf the potential supplier, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet their reliable electricity needs.").

[5] Between January 1999 through June 2000, this percentage was twenty-five percent of the margins. During the remainder of the reconciliation period, there was a 50-50 split.

from its sales of contingent capacity and energy to IID (which were considered off-system sales)[6] utilizing its average system production cost, a treatment it viewed as consistent with its contractual obligation to serve the sales from its total system resources. Similarly, EPE allocated the average production costs and resultant margins among the jurisdictions it serves—Texas, New Mexico, and the wholesale or "federal" jurisdiction, treating IID as a separate wholesale customer. The City asserted that EPE instead should have calculated margins based on its incremental costs of these sales and that no portion of the margins should have been allocated to the wholesale jurisdiction. Consequently, the City reasoned, EPE's calculation overstated the eligible fuel costs properly allocable to the utility's Texas retail customers. Both the ALJs and the Commission rejected the City's assertions.

Proceedings below

EPE and the City each sued for judicial review of the Commission's order. The suits were consolidated. The district court subsequently rendered final judgment affirming the Commission's order in full. Both EPE and the City have appealed.

ANALYSIS

EPE brings four issues on appeal. The first three challenge the Commission's imputation of capacity costs to its SPS 2000 contract. EPE asserts that (1) substantial evidence does not reasonably support the Commission's findings that the SPS 2000 contract contained embedded capacity costs; (2) the Commission's decision to impute capacity costs to the contract violates the

[6] EPE also sold firm capacity and energy to IID as part of its native load.

"letter and spirit" of the 1995 Stipulation/Agreed Order; and (3) the Commission's imputation of capacity costs to the contract is preempted by the filed-rate doctrine. In its fourth and final issue, EPE asserts in the alternative that the Commission's refusal to grant its special-circumstances request was arbitrary and capricious.

The City brings three issues in its appeal. First, it argues that the Commission's decision to reject the ALJs' recommendations concerning the amount and cost of imputed capacity charges was the result of improper procedure and not supported by substantial evidence. In its second and third issues, the City complains that substantial evidence does not support the Commission's calculation of EPE's margins from its off-system sales to IID or its jurisdictional allocation of those margins.

Standard of review

We review the Commission's order here under the Administrative Procedure Act's (APA) "substantial-evidence" standard. *See* Tex. Util. Code Ann. § 15.001 (West 2007) ("Any party to a proceeding before the commission is entitled to judicial review under the substantial evidence rule."). This standard requires that we reverse or remand a case for further proceedings "if substantial rights of the appellant have been prejudiced because the administrative findings, inferences, conclusions, or decisions" are

(A) in violation of a constitutional or statutory provision;

(B) in excess of the agency's statutory authority;

(C) made through unlawful procedure;

(D) affected by other error of law;

(E) not reasonably supported by substantial evidence considering the reliable and probative evidence in the record as a whole; or

(F) arbitrary or capricious or characterized by abuse of discretion or clearly unwarranted exercise of discretion.

Tex. Gov't Code Ann. § 2001.174(2) (West 2008). However, we may not substitute our judgment for that of the agency on the weight of the evidence on matters committed to agency discretion. *Id.* § 2001.174(1); *Southwestern Pub. Serv. Co. v. Public Util. Comm'n of Tex.*, 962 S.W.2d 207, 215 (Tex. App.—Austin 1998, pet. denied). With respect to subparagraph (E), "substantial evidence" does not mean a large or considerable amount of evidence but such relevant evidence as a reasonable mind might accept as adequate to support a conclusion of fact. *Pierce v. Underwood*, 487 U.S. 552, 564-65 (1988); *Lauderdale v. Texas Dep't of Agric.*, 923 S.W.2d 834, 836 (Tex. App.—Austin 1996, no writ). The test is not whether the agency made the correct conclusion in our view, but whether some reasonable basis exists in the record for the agency's action. *Railroad Comm'n of Tex. v. Pend Oreille Oil & Gas Co., Inc.*, 817 S.W.2d 36, 41 (Tex. 1991). We must uphold an agency's finding even if the evidence actually preponderates against it, so long as enough evidence suggests the agency's determination was within the bounds of reasonableness. *Southwestern Pub. Serv. Co.*, 962 S.W.2d at 215.

To the extent that the parties' issues turn on the construction of a statute, we review these questions de novo. *First Am. Title Ins. Co. v. Combs*, 258 S.W.3d 627, 631 (Tex. 2008). Although we are to give "serious consideration"—i.e., deference—to a governmental agency's construction of a statute it is charged with administering, this principle presupposes that the statute is ambiguous and the agency's construction is reasonable and does not conflict with the statute's language. *Railroad Comm'n of Tex. v. Texas Citizens for a Safe Future & Clean Water*, 336 S.W.3d 619, 624-25 (Tex. 2011).

In general, "[w]e construe administrative rules, which have the same force as statutes, in the same manner as statutes." *Rodriguez v. Service Lloyds Ins. Co.*, 997 S.W.2d 248, 254 (Tex. 1999). "Unless the rule is ambiguous, we follow the rule's clear language." *Id*. However, similar to the "serious consideration" principle where it applies, we defer to an agency's interpretation to the extent the regulation is ambiguous or leaves room for policy determinations, but not where the administrative interpretation is plainly erroneous or inconsistent with the regulation. *Id.* at 254-55 (quoting *Public Util. Comm'n of Tex. v. Gulf States Util. Co.*, 809 S.W.2d 201, 207 (Tex. 1991)).

In interpreting the purchased-power contracts at issue here, as well as the 1995 Stipulation/Agreed Order, we are guided by principles of contract construction. *See Cities of Abilene v. Public Util. Comm'n of Tex*., 146 S.W.3d 742, 747 (Tex. App.—Austin 2004, no pet.). Construction of an unambiguous contract presents a question of law that we review de novo. *See State v. Shumake*, 199 S.W.3d 279, 284 (Tex. 2006). In construing a written contract, the primary concern of the court is to ascertain the true intentions of the parties as expressed in the instrument. *J.M. Davidson, Inc. v. Webster*, 128 S.W.3d 223, 229 (Tex. 2003). We must examine and consider the entire writing in an effort to harmonize and give effect to all the provisions of the contract so that none will be rendered meaningless. *Id.* at 229. No single provision taken alone will be given controlling effect; rather, all the provisions must be considered with reference to the whole instrument. *Id.*

Likewise, the threshold question of whether a contract is ambiguous is a question of law for the court. *Id.* If a contract is unambiguous—i.e., it can be given a definite or certain legal meaning—an administrative interpretation of the contract is not entitled to a presumption of validity. *Cities of Abilene*, 146 S.W.3d at 748. If a contract is found to be ambiguous—i.e., susceptible to more than one reasonable meaning, such that the parties' intent must be determined as a matter of fact—we must affirm the agency's interpretation if it is supported by substantial evidence. *Id.*

Capacity costs

EPE's issues

We first consider EPE's three issues challenging the Commission's imputation of capacity costs to the SPS 2000 contract. In support of its first issue—challenging whether substantial evidence supports the Commission's findings and conclusions that the contract reflected a conveyance of capacity—EPE begins by arguing that the Commission's findings are predicated upon an erroneous construction of the contract.

Under the contract, as EPE acknowledges, it agreed to the following:

> [EPE] agrees to purchase and [SPS] agrees to provide, during the term of this Transaction Agreement, *Firm Power Service* in the amount of 50 Megawatts for all months during the term, and an additional 50 Megawatts for the months of June through October ("Firm Power").

(Emphasis added.) EPE further acknowledges that the contract defines "Firm Power Service" as:

> that quantity of firm *capacity*, with reserves, and associated energy that the Company will make continuously available to the Customer from the Company's generation resources, which include *capacity* purchases.

(Emphases added.) Although their plain text, standing alone, would seem to suggest otherwise, EPE insists that when these provisions are construed in conjunction with other portions of the contract, it becomes apparent that the provisions merely contemplate that EPE *could* purchase capacity under the contract and do not establish that EPE actually did so. *See J.M. Davidson, Inc.*, 128 S.W.3d at 229 (contractual provisions must be construed with reference to the entire instrument and all provisions given effect). EPE emphasizes other portions of the contract defining "demand charges"—the "amount, *if any*, to be paid by the Buyer to Seller for capacity as agreed to by the Parties in a Transaction"—and "contract price"—"the price in $U.S. per MWh (unless otherwise provided for) to be paid by Buyer to Seller for the purchase of Power, including the Power Price, Demand Charges, Transmission Charges and any other charges, *if any*, pursuant to a Transaction." (Emphases added.) Together, these provisions, EPE contends, reflect only a contract whereby it *might agree* to purchase capacity or "demand," and contemplating that, in such an event, SPS would impose a separate, explicit charge for that product. Because there is no evidence that SPS imposed or EPE paid any explicit charges for "capacity" or "demand" in connection with the purchased-power expenses it claims under the SPS 2000 contract, EPE reasons, the evidence establishes as a matter of law that it did not purchase capacity.[7]

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[7] EPE also contrasts this absence of explicit "capacity" charges with examples of transactions where it did explicitly purchase "capacity."

Relatedly, EPE argues more broadly that the "firm power service" it purchased under the SPS 2000 contract, though defined with reference to "capacity," did not actually represent a purchase of *capacity* if that term is properly understood. EPE points to the testimony of Steve Buraczyk, its Supervisor of Resource Management, who asserted that the reference to "capacity" in the contract's "firm power service" definition referred to an obligation of SPS to back the sale with its own reserves and capacity purchases. While EPE acknowledges that this "firm energy purchase . . . backed by the seller's capacity provides a greater degree of reliability because the seller must plan for the sale as part of its native load and resources plan," it insists that the transaction nevertheless does not signify a *capacity* purchase because "it does not provide the type of planning flexibility to the purchaser traditionally associated with the purchase of capacity." Citing further testimony of Buraczyk and its other witnesses, EPE urges that a *capacity* product is distinguished by a fixed premium, separate from energy charges, that conveys dispatch rights on the part of the buyer, such that the buyer has the right—though not the obligation—to schedule or call upon energy up to the contract amount if and when needed. Only if and when a capacity purchaser opts to take power, EPE adds, would it pay an energy charge for the power it took. What EPE purchased under the SPS 2000 contract, the utility asserts, was not "capacity" in this sense because it did not pay a fixed premium for or receive dispatch rights. Instead, EPE insists, it purchased a distinct "firm energy" product, requiring EPE either to take power in the specified amount or pay liquidated damages. EPE further emphasizes evidence that it did not subjectively intend to purchase capacity (so defined), citing testimony from Buraczyk that the utility opted to purchase blocks of "firm energy" rather than "capacity" because it perceived this approach to be more cost-effective and to provide it greater flexibility. Similarly, EPE urges that whether the contract reflected a "long-term purchase . . . made in advance as part of [its] planning process designed to meet [its] resource needs for reliability," as the Commission found, was not in itself determinative of a capacity purchase because the same might be said of its "firm energy" purchase.

EPE's arguments disputing whether the SPS 2000 contract conveyed "capacity" ultimately rest upon a construction of that term as it was used in Former Fuel Rule § 23.23(b)(2)(B)(iv)'s exclusion of "demand or capacity costs" from recoverable "eligible fuel expenses." Undercutting EPE's arguments, the rule does not require that a sale of "capacity" include dispatch rights or that there be an explicit charge for capacity. Indeed, the rule does not specify any definition of "demand or capacity costs" or explain how such costs are to be determined. The Commission's findings and conclusions, previously summarized, reflect that it construed and applied the rule in a manner consistent with the historical association of "capacity" charges with a wholesale seller's fixed costs of making generation assets available to generate power, *see City of El Paso*, 851 S.W.2d at 898; *Gulf States Utils.*, 841 S.W.2d at 461, and the objective—mandated in both the Former Fuel Rule and the 1995 Stipulation/Agreed Order—of preventing recovery of such base-rate costs in the guise of reconcilable fuel expenses.

As the Commission concluded, the conveyance of a dispatch right—which entails a corresponding duty on the part of the wholesale seller to make its generation assets available separate and apart from any sales of energy that transpire—is "one indicator that a power purchase contract has a capacity component," but it is not the exclusive indicator. While the SPS 2000 contract did not convey dispatch rights to EPE, the Commission concluded that it nonetheless reflected a conveyance of capacity. This conclusion is supported by the text of the contract. The "firm power service" EPE purchased explicitly included "firm capacity, with reserves, and associated energy that [SPS] will make continuously available to [EPE] from the Company's generation resources, which include capacity purchases." EPE agreed to purchase and SPS agreed to provide "50 Megawatts of [firm power service] for all months during the [contract] term, and an additional 50 Megawatts for the months of June through October. . . ." EPE agreed to pay specified rates (varying by month) per MWh of energy supplied, with an additional charge per MWh over the 50 MW for the additional power provided during June through October. If SPS failed to make the energy available as requested, EPE was permitted to buy it on the market and require SPS to compensate it for any cost in excess of the contract price. Although EPE emphasizes that it was obligated to pay "liquidated damages" if it ultimately did not take the power, urging that this provision distinguishes its "firm energy" purchase from a true "capacity" purchase entailing dispatch rights, the Commission asserts, and we agree, that the provision's significance is instead that it can signal compensation to SPS for fixed costs in making the power available. Additionally, the contract permitted EPE to schedule power for almost immediate delivery. During the "On-Peak Period," the contract required EPE to notify SPS on the day before delivery. During the "Off-Peak Period," EPE could notify SPS two hours before delivery. These features of the SPS 2000 contract, considered as a whole, demonstrate that the "firm power service" EPE purchased included reciprocal obligations on the part of SPS to make its generation assets available to provide power, not merely the sale of the power itself.

In addition to the contract terms, the Commission also cited the "long-term" nature of EPE's purchase and that the utility made the purchase to ensure reliability as consistent with the circumstances in which utilities make capacity purchases. *See Entergy Gulf States, Inc.*, 173 S.W.3d at 211 (citing these factors, among others, in affirming Commission's order finding embedded capacity costs); *see also AEP Tex. Cent. Co. v. Public Util. Comm'n of Tex.*, 286 S.W.3d 450, 471 (Tex. App.—Corpus Christi 2008, pet. denied). While disputing whether such facts can be singularly determinative of a capacity sale, EPE acknowledges that they may nonetheless be "indicative of a circumstance in which a utility may purchase capacity."

On this record, the Commission could have reasonably determined that EPE had paid not only for the variable "energy" costs of the power it took, but SPS's fixed costs of making its generation assets available. And the Commission's application of the Former Fuel Rule to these facts to conclude that EPE's purchases had a "capacity" component, we further hold, was reasonable and not plainly erroneous or inconsistent with the rule. *See Rodriguez*, 997 S.W.2d at 254; *Gulf States Util. Co.*, 809 S.W.2d at 207. Consequently, we give it deference, and overrule EPE's first issue.

In its second issue, EPE argues that this construction and application of the Former Fuel Rule violated the terms to which the Commission agreed in the 1995 Stipulation/Agreed Order. Under this order, as previously explained, EPE and the Commission agreed that the utility's base rates would be frozen for ten years, the utility would be prohibited from shifting base-rate costs to fuel costs, and that the utility's cost recovery would be limited solely to the frozen base rates and "those costs recovered as reconcilable fuel costs according to [the Former Fuel Rule]." Emphasizing that the order preceded the *Entergy* case by several years, EPE urges that the rule's exclusion of "demand or capacity costs," as construed at the time of the agreement and order, did not include the concept of embedded or imputed capacity purchases, but meant only "capacity" or "demand" charges that were explicitly identified and charged in purchased-power contracts. EPE also points to evidence that, by 1995, single-priced energy purchases had already come into existence and that it had made firm energy purchases without having a capacity charge imputed. By subsequently imputing capacity costs to the SPS 2000 contract, EPE complains, the Commission "turns the 1995 understanding of capacity costs on its head" and, in EPE's view, violated its agreement to permit EPE to recover fuel costs as it would have been permitted to do in 1995.

The Commission responds that EPE is "simply wrong" that it had denied the utility recovery of purchased-power costs to which it would have been entitled in 1995. It emphasizes that the Former Fuel Rule has always denied recovery of "demand or capacity costs" in fuel reconciliations and that this prohibition has not been limited solely to capacity or demand costs that are separately priced. That the exclusion had typically been *applied* to explicit "capacity" charges (as the charges were commonly imposed prior to wholesale market deregulation) or had not been applied to some other EPE purchased-power agreement, the Commission reasons, did not preclude its application where, as here, it determines that capacity costs are embedded in what are nominally energy costs.

As previously suggested, the Commission's construction of the Former Fuel Rule is reasonable, not plainly erroneous or inconsistent with the rule, and entitled to deference. *See Rodriguez*, 997 S.W.2d at 254; *Gulf States Util. Co.*, 809 S.W.2d at 207. That rule, in turn, defines what costs EPE can recover under the plain language of the 1995 Stipulation/Agreed Order: "[T]he only costs that may be recovered . . . are those costs recovered as reconcilable fuel costs according to [the Former Fuel Rule]." Under the Former Fuel Rule, capacity costs may not be recovered as eligible fuel expenses, and there is no language in the 1995 Stipulation/Agreed Order limiting application of the Former Fuel Rule solely to explicitly identified "capacity" costs as opposed to imbedded capacity costs. Rather, it simply and unambiguously provides that capacity costs are not recoverable as eligible fuel expenses. *See Cities of Abilene*, 146 S.W.3d at 747 (primary concern in construing agreement is to ascertain true intentions of parties as expressed in written instrument). Accordingly, we overrule EPE's second issue.

In its third issue, EPE argues that the Commission's imputation of capacity costs to the SPS 2000 contract is preempted by the filed rate doctrine because the contract was filed with and accepted by the Federal Energy Regulatory Commission (FERC). The parties agree that FERC has exclusive jurisdiction to regulate the sale of electricity at wholesale in interstate commerce. *See* 16 U.S.C. § 824(b) (2010) (jurisdiction extends to "the transmission of electric energy in interstate commerce and to the sale of electric energy at interstate commerce"); *Entergy La., Inc. v. Louisiana Pub. Serv. Comm'n*, 539 U.S. 39, 41 (2003); *Entergy Gulf States, Inc.*, 173 S.W.3d at 207. Further, it is undisputed that, when FERC has set a rate between a purchaser and seller of wholesale power, a state may not exercise its jurisdiction over retail sales to prevent the seller from recovering the FERC-approved rate, impermissibly "trapping" costs. *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 372 (1988). The parties also agree that FERC-set wholesale rates apply in this instance.[8] They disagree, however, as to whether, because the SPS 2000 contract was filed

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[8] The City asserts that "EPE does not identify where in the record this contract was the subject of a FERC proceeding, or a FERC approved rate," but the SPS Master Power Purchase and Sale Agreement expressly provides that its effectiveness is "contingent upon its acceptance for filing by the FERC."

with and accepted by FERC, the Commission is jurisdictionally prohibited from determining the manner by which retail rates may be recovered. *See id.*

As the Commission observes, it has not challenged the reasonableness of EPE's FERC-filed rates, and whether EPE can fully recover its purchased-power costs is not at issue. Rather, the question presented is *how* these costs can be recovered—through base rates or the fuel factor. While the filed-rate doctrine prohibits the Commission from challenging EPE's FERC-filed rates, the Commission's determination of the manner by which those rates can be recovered is consistent with the doctrine and FERC's authority. *See, e.g.*, *Centerpoint Energy Entex v. Railroad Comm'n of Tex.*, 208 S.W.3d 608 (Tex. App.—Austin 2006, pet. dism'd); *Gulf States Utils.*, 841 S.W.2d at 459.

EPE argues that, by imputing a capacity cost that was not expressly included in the FERC-filed tariff, the Commission has failed to give binding effect to a FERC-approved power rate and, by failing to do so, has varied the express terms of the SPS 2000 contract. According to EPE, "the Commission has imputed a demand or capacity cost when the FERC-approved rate contained none." However, EPE's argument rests on the incorrect assumption that the FERC-approved rate did not include capacity costs. Consequently, we overrule EPE's third issue for the same reasons we have rejected its first two.

In its fourth and final issue, asserted as an alternative to its arguments challenging whether the Commission properly imputed capacity costs to the SPS 2000 contract, EPE urges that the Commission abused its discretion in refusing to grant EPE's special-circumstances request and preventing EPE from recovering the costs as part of its reconcilable fuel expenses. *See*

Former Fuel Rule § 23.23(b)(2)(B)(v). EPE asserts that the record demonstrates that its purchases "giving rise to the ineligible fuel expense . . . resulted in, or is reasonably expected to result in, increased reliability of supply or lower fuel expenses than would otherwise be the case, and that such benefits received or expected to be received by ratepayers exceed the costs that ratepayers would have paid or otherwise would reasonably expect to pay." *Id.* § 23.23(b)(2)(B). EPE emphasizes the Commission's findings that its power purchases under the SPS 2000 contract were aimed at ensuring reliability. It also cites evidence to the effect that it always purchased the cheapest available power product to reliably serve its customers. EPE additionally urges that unless it is permitted to recover these costs, its ability to recover its "legitimate" fuel costs will be forever precluded—i.e., the costs will be "trapped." Finally, EPE asserts that because the Commission only disallowed expressly delineated capacity costs when the 1995 Stipulation/Agreed Order was adopted, EPE had no notice that its purchased-power contracts would be subject to an imputed-capacity analysis and, as a result, it was deprived of procedural due process. Under these circumstances, EPE argues, special-circumstances treatment is justified, and it was arbitrary and capricious for the Commission to determine otherwise. We disagree.

First, we note that at all relevant times, Commission rules expressly prohibited the recovery of capacity costs as eligible fuel expenses. *See id.* § 23.23(iv); 16 Tex. Admin. Code § 25.236. Thus, EPE has had notice that it would not be allowed to claim capacity costs as eligible fuel expenses. The fact that this rule had been previously applied by the Commission to exclude only separately-priced capacity costs does not prohibit the Commission from disallowing capacity costs it otherwise finds in contracts, nor does it somehow render EPE's awareness of the prohibition less comprehensive. Plainly stated, the Former Fuel Rule disallows capacity costs as recoverable fuel expenses.

Further, even assuming that EPE's actions would satisfy certain of the non-exclusive special-circumstances factors listed in Former Fuel Rule § 23.23(v), we cannot conclude that the Commission acted arbitrarily and capriciously in denying special-circumstances treatment. Capacity costs, as previously explained, are among the fixed costs that are recoverable through base rates. Consequently, each time EPE resold the power it had purchased from SPS, its base rate compensated it for capacity costs—i.e., no costs were "trapped." *See Entergy Gulf States, Inc.*, 173 S.W.3d at 209 (rejecting "trapping" argument because utility failed to show that it had not recovered its non-fuel costs through its base rate). For the same reasons, to permit EPE to recover the same costs as part of fuel expenses would result in a double recovery. Given that the Former Fuel Rule's exclusion of capacity costs from reconcilable fuel costs reflects the policy goal of preventing such double recoveries, we cannot conclude that the Commission acted arbitrarily or capriciously in refusing EPE's special-circumstances request. We overrule EPE's fourth issue.

The City's issues

In contrast to EPE, which contends that the Commission erred in imputing and excluding any capacity costs from its purchased-power expenses during the reconciliation period, the City complains in its first issue that the Commission did not go far enough in excluding such costs. The City argues, first, that the Commission did not follow proper procedure in rejecting the ALJs' findings and conclusions regarding the existence and amount of capacity costs in EPE's purchased-power contracts.

The APA authorizes the Commission to change an ALJ's findings of fact or conclusions of law or to modify an order issued by an ALJ if the Commission determines that a finding of fact was not supported by a preponderance of the evidence or if the Commission determines that the ALJ has misapplied or misinterpreted prior agency decisions. *See* Tex. Gov't Code Ann. § 2003.049(g) (West 2008). Under section 2003.049(g), the Commission may substitute its judgment for the ALJ's on questions of fact. *Southwestern Pub. Serv. Co.*, 962 S.W.2d at 214. To modify an ALJ order, however, the agency must "state in writing the specific reason and legal basis for its determination." *See* Tex. Gov't Code Ann. § 2003.049(h); *Southwestern Pub. Serv. Co.*, 962 S.W.2d at 214.

Here, the Commission rejected the ALJs' proposal to impute $30.05 million in capacity to EPE's purchased-power contracts both on the grounds that the ALJs had misinterpreted prior Commission decisions and that their findings were inconsistent with the evidence. As the Commission explained in its final order:

> The Commission has historically looked to the pricing structure in purchased-power contracts to determine whether the contract contained capacity costs. Deregulation of the electric industry has necessarily led to many changes. One of those changes has been a trend to change the pricing of purchased-power contracts. Pricing is no longer constrained by cost-of-service regulations; contracts now reflect free-market considerations. The question now faced by this Commission is how to identify capacity costs in market-based purchased-power contracts.
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> . . . .
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> This contract contained language indicating that there was a capacity component to the purchase even though there was no explicit charge for that component. In addition, that contract was for a long-term purchase and was made in advance as part of EPE's planning process designed to meet EPE's resource needs for reliability. The power was purchased to serve native peak load and included additional purchased power during the peak summer months of the contract. Because of the contract

> language, and because of other characteristics of the contract and manner in which the power was acquired and used are consistent with such a finding, the Commission finds that the SPS contract included capacity costs in the contract price.

The Commission also explained that, in its view, the ALJs had misinterpreted and misapplied the Commissions's reasoning in the *Entergy* case. We conclude that the Commission's modifications of the ALJs' findings, conclusions, and proposed order were not improper procedurally. *See id.*

The City also urges that the Commission's chosen method for calculating imputed capacity costs and the amount it ultimately determined were not supported by substantial evidence. We disagree.

The Commission concluded that the WSPP price cap of $7.32/kW-month was a "reasonable" proxy for the capacity costs contained in the SPS 2000 contract, observing that "[t]he amount is based upon the fixed costs of the WSPP's members' units and is representative of the actual market cost for capacity during the reconciliation period." Although the City argues that there is no evidence to support the Commission's conclusions because the WSPP agreement itself was never admitted into evidence, the evidence in the record reasonably supports the Commission's conclusion. In proposing the WSPP proxy, EPE presented evidence in the form of rebuttal testimony from its witness Steve Buraczyk regarding examples of capacity charges in products available in EPE's market. Buraczyk testified that "the WSPP agreement . . . includes a cost-based price cap for fixed costs that is $7.32/kW-month," and that the "WSPP agreement is an industry-recognized form agreement that is available on the WSPP website." Burzaczyk gave several examples of capacity or demand charges in the western market during an eight-year period that included the reconciliation period. He identified a 1998 contract to purchase capacity from SPS for one year that contained a separately-stated, fixed capacity charge of $4.578/kW-month. Buraczyk also identified a 2002 contract for delivery of capacity that contained a separately-stated, fixed capacity charge of $5.31/kW-month.

In addition, EPE presented evidence showing that the WSPP includes more than 220 members, comprised of a diverse group of sellers and consumers involved in wholesale transactions; that the WSPP agreement is a pool-wide, cost-based rate, filed with FERC; that EPE conducted most of its wholesale transactions under the terms of this agreement during the reconciliation period; that this pool-wide approach has been upheld in federal court;[9] and that the 7.32/kW-month fixed cost price cap is based on the FERC's analysis of WSPP members, including EPE, that are likely to participate in power purchases. Based on this evidence, there was a reasonable basis for the Commission's decision to use the $7.32/kW-month proxy. *See Southwestern Pub. Serv. Co.*, 962 S.W.2d at 215. From here, the Commission multiplied the proxy measure times the amount of purchased power EPE acquired under the SPS 2000 contract to yield the $6.2 million total company disallowance. It follows from the foregoing that this total, too, was reasonably supported by substantial evidence.

In addition to arguing that the Commission's choice and application of the WSPP proxy was not supported by substantial evidence, the City urges that substantial evidence does not support the Commission's decision not to impute capacity costs to other EPE purchased-power contracts during the reconciliation period. The City's complaint is premised on the validity of the ALJs' proposed methodology for identifying capacity—i.e., that capacity costs exist under the

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[9] *See Environmental Action v. Federal Energy Regulatory Comm'n*, 996 F.2d 401, 408-09 (D.C. Cir. 1993).

contracts because EPE paid more for the power it acquired than its own marginal cost of generation. In rejecting the ALJ's methodology, the Commission acknowledged that a variety of market factors other than fixed-cost recovery could explain why a utility would pay more for "energy" costs than its own variable costs of generation. The Commission noted, for example, that EPE did not have sufficient generation to serve all of its load during the reconciliation period. In light of this, the Commission acted reasonably in concluding that looking primarily to this cost differential would not be a viable indicator of when capacity costs are imbedded in a purchased-power contract. Further, the evidence shows that the contracts for 1999 and 2001 do not include the kind of language that the Commission relied on in the SPS 2000 contract to determine that the SPS 2000 contract included capacity costs. For example, the 1999 and 2001 SPS contracts did not define "firm power service" as "that quantity of firm capacity with reserves, and associated energy that the Company will make continuously available to the customer for the Company's generations resources, which include capacity purchases." In sum, the Commission's conclusion that only the SPS 2000 contract included capacity costs is supported by substantial evidence. We overrule the City's first issue.

Off-system sales

The City's remaining two issues concern the calculation and allocation of EPE's margins from off-system sales—i.e., its sales of contingent capacity with energy—to IID during the reconciliation period. Specifically, the City asserts that substantial evidence does not support the Commission's decision to permit EPE (1) to use its average system-wide cost of producing power, rather than its incremental cost, in determining its margins from the sales, and (2) to allocate a portion of those margins to the wholesale or "federal" jurisdiction.

In regard to these issues, the Commission made the following pertinent fact findings:

53. It is not appropriate to assign an incremental cost to the IID-C sales in order to calculate the margin for those sales because, unlike opportunity sales, they are not based on incremental costs.

54. Consistent allocation of the Company's margins requires the IID-C sales to be included in the jurisdictional allocation because the sales are served from the Company's total system.

Costs

According to the City, the Commission should have calculated EPE's margins from its off-system sales to IID using the difference between the sale price and the calculated cost of the most expensive generation or resource on EPE's system—i.e., the incremental cost of the sale—because that is how EPE calculated margins for its other off-system sales and there is no valid basis in the evidence for treating this sale differently. We disagree.

There is substantial evidence to support the Commission's approval of the calculation method EPE used here. Most notably, the IID contract terms specify that EPE's sales are to be served from its total system resources. In other words, as the Commission found, EPE's off-system sales were not "opportunity" sales, where a utility sells power based on an opportunity to earn revenue exceeding the marginal or incremental cost of generation, but were based instead on a contractual commitment to sell power at a price determined according to a contractual formula, contingent upon the utility having sufficient capacity in its total system. Additionally, EPE's charges are calculated based on a base-fuel cost, plus an adjustment charge derived from the cost of fossil and nuclear fuel consumed in EPE's plants, actual costs associated with purchased energy, net energy costs of economic dispatch, and the cost of fossil and nuclear fuel recovered through inter-system sales. As EPE's witness Thomas Newsom confirmed, this pricing scheme reflects the contractual requirement that the sales be served from EPE's total system resources. Under this contract, Newsom further opined, it was inappropriate to calculate EPE's margins from the sale based on the incremental costs of those sales. This evidence reasonably supports the Commission's findings that EPE's margins from the sales should—consistent with the contract—be determined based on average systemwide costs of producing power rather than incremental costs. We overrule the City's second issue.

Allocation of margins

Although the City's complaint about EPE's allocation of the IID off-system sales margins is presented as an issue distinct from its challenge to the Commission's choice of average systemwide costs over incremental costs in determining those margins, the two are logically connected to the extent the Commission found that "[c]onsistent allocation of [EPE]'s margins requires the IID[] sales to be included in the jurisdictional allocation because the sales are served from [EPE]'s total system." EPE's witness Newsom testified that EPE had consistently treated IID as a separate wholesale customer for jurisdictional allocation purposes and that the pricing of the sales dictates the allocation. He testified that, to be consistent, the IID sales must be included in the jurisdictional allocation because the sales are served from the entire system. Although the City disagreed with the method used and proffered testimony that off-system sales customers, such as IID, should not be allowed to share in the profits arising from energy sales to those facilities because they have not paid for the generation facilities, Newsom's testimony, along with the evidence relevant to the cost issue, reasonably supports the Commission's finding that the IID sales should be included in the jurisdictional allocation. Accordingly, we overrule the City's third issue.

CONCLUSION

Having overruled each issue presented by EPE and the City, we affirm the district court's judgment.

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Bob Pemberton, Justice

Before Justices Patterson, Puryear and Pemberton;
Justice Patterson not participating

Affirmed

Filed: July 1, 2011