United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued November 7, 2005 Decided December 30, 2005

No. 04-1324

SOUTHERN CALIFORNIA WATER COMPANY,
PETITIONER

V.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT

MIRANT AMERICAS ENERGY MARKETING, L.P.,
INTERVENOR

On Petition for Review of Orders of the
Federal Energy Regulatory Commission

Randolph Lee Elliott argued the cause and filed the briefs for petitioner.

Carol J. Banta, Attorney, Federal Energy Regulatory Commission, argued the cause for respondent. With her on the brief were *Cynthia A. Marlette*, General Counsel, and *Dennis Lane*, Solicitor.

Before: HENDERSON and BROWN, *Circuit Judges*, and WILLIAMS, *Senior Circuit Judge*.

Opinion for the Court filed by *Senior Circuit Judge* WILLIAMS.

WILLIAMS, *Senior Circuit Judge*: Southern California Water Company, a public utility that distributes electricity to retail customers in San Bernardino County, California, challenges two orders of the Federal Energy Regulatory Commission. It contends that the Commission misapplied the concept of "incremental cost" as used in the Western System Power Pool ("WSPP") Agreement; as a result, Southern California says, FERC incorrectly found that a sale of electricity by Southern California violated statutory filing requirements for the making of jurisdictional sales. See Federal Power Act, § 201, 16 U.S.C. § 824. Because the Commission failed to explain its interpretation of incremental cost adequately, we reverse and remand.

* * *

At the beginning of March 2001, Southern California was committed to buying electricity for its retail customers in two wholesale contracts: (1) a baseload contract with Dynegy Power Marketing for 12 megawatts ("MW") of around-the-clock energy at $35.50 per megawatt-hour ("MWh"), and (2) a contract with Illinova Energy Partners ("IEP") to meet any hourly demand in excess of 12 MW at "SP15," a name given the spot market price in the "South of Path 15" zone, a common delivery point. (Dynegy later assumed IEP's obligations, but for ease in distinguishing between the baseload and the spot-price contracts we refer to this as the IEP contract.) As the Dynegy contract was scheduled to expire on April 30, 2001, Southern California entered into a contract with Mirant Americas Energy Marketing on March 16 to purchase 15 MW of around-the-clock energy at a price of $95/MWh. The contract was under the WSPP Agreement, which the parties identified as the "enabling agreement."

For reasons not entirely clear, the Mirant baseload contract was to start April 1, 2001, and thus overlapped with the Dynegy baseload contract for the month of April. To address this overlap, Southern California entered into a separate contract with Mirant on March 30, 2001, again under the WSPP Agreement, agreeing this time to *sell* Mirant 15 MW of around-the-clock energy for the month of April at a price of SP15 minus $20/MWh. Although the overlap of baseload contracts obviously occasioned Southern California's interest in making such a sale, the one-month contract was not formally tied to or contingent on the Mirant baseload contract. In the immediate run-up to the March 30 contract, the SP15 price fluctuated between a peak high of about $280 and an off-peak low of about $80. These were historically high prices; March 2001 fell in the midst of California's well-known electricity crisis.

At the time of the April 2001 sale, Southern California had no authority to sell energy at market-based prices. In July 2002, in a move unrelated to the April sale, it applied to the Commission for such authority. Mirant intervened, seeking a refund and contending that the April 2001 sale was itself at market-based rates. The Commission granted Southern California the requested authority prospectively, *Southern California Water Co.*, 100 FERC ¶ 61,373 (2002), but simultaneously initiated an inquiry into the April 2001 sale.

Southern California defended the sale on the ground that the rates were not "market-based" but cost-based, as they fell (it argued) within the WSPP Agreement's cost-based limit–its provision that prices must not "exceed the Seller's forecasted Incremental Cost" plus a so-called "adder." It argued that the relevant incremental cost was SP15, the price that it would pay IEP for the last unit needed to meet the obligation to Mirant whenever its total sales commitments (i.e., the sum of (1) its retail customers' demand, which typically ran between 12 and 17 MW, with occasional deviations in both directions, see Joint Appendix ("J.A.") 310-23, and (2) the 15 MW needed for the April 2001 sale to Mirant) exceeded the 27 MW that it could count on from its baseload contracts with Dynegy and Mirant.

The Commission rejected this defense, classified the sale as having been at market-based rates and therefore unauthorized, and ordered a refund of the difference between the revenue collected under the contract and $95/MWh (the price under Southern California's baseload contract with Mirant), plus interest. See 106 FERC ¶ 61,305 (2004) ("*Compliance Order*"), *order on reh'g*, 108 FERC ¶ 61,168 (2004) ("*Rehearing Order*"). In denying rehearing the Commission explained its rejection of the argument that SP15 equaled "incremental cost" under the WSPP Agreement, saying that SP15 "would only be [Southern California's] incremental cost *once the sale to Mirant is consummated*." *Rehearing Order*, 108 FERC at P 14, p. 62,022 (emphasis added). In addition, the Commission relied on the arguments that Southern California "simply resold" to Mirant the same energy that it bought, 106 FERC at P 17, p. 62,198, and that the incremental cost could not have been SP15 because SP15 exceeded its sale price of SP15 minus $20/MWh, 108 FERC at P 14, p. 62,022.

In a later order the Commission reduced the refund by the amount of an "adder," which the WSPP Agreement allowed in excess of incremental costs for all sales under the Agreement that were not at market-based rates. The Commission explained that it now understood that the Agreement permitted sellers to charge the adder on top of the forecasted incremental cost, because the Agreement made "no distinction between owned resources and purchase contracts." *Southern California Water Company*, 109 FERC ¶ 61,121 at P 12, p. 61,504 (2004).

Southern California challenges the *Compliance Order* and the *Rehearing Order* as being arbitrary and capricious, 5 U.S.C. § 706(2)(A), and as unsupported by substantial evidence, 16 U.S.C. § 825*l*(b).

* * *

The crux of the case is whether the Commission coherently explained its conclusion that the price of Southern California's April sale to Mirant exceeded the cost-based ceiling established by the WSPP Agreement–Southern California's "forecasted Incremental Cost." The Agreement defines that term as "[t]he forecasted expense incurred by the Seller in providing an additional increment of energy or capacity during a given hour." Western Systems Power Pool Agreement § 4.9, J.A. 219.

The Commission's prior orders have shed little interpretive light on the phrase. In initially approving the Agreement, the Commission said that "the seller's incremental cost for setting ceiling prices should be forecasted at the time of specific transactions under an agreement to reflect the actual cost with greater certainty" and that "incremental cost may be forecasted hourly, weekly, or monthly," *Western Systems Power Pool*, 55 FERC ¶ 61,099 (1991) ("*Western Systems Power Pool I*"), *order on reh'g*, 55 FERC ¶ 61,495 at 62,718 (1991) ("*Western Systems Power Pool II*"), *aff'd sub nom.*, *Environmental Action v. FERC*, 996 F.2d 401 (D.C. Cir. 1993). In *El Paso Electric Co.*, 105 FERC ¶ 61,107 (2003), the Commission approved El Paso's incremental cost methodology without explanation, but did make clear that a firm without authority for market-based sales could sell under WSPP's incremental-cost ceiling, a point confirmed in *NorthPoint Energy Solutions, Inc.*, 107 FERC ¶ 61,181 (2004).

At the outset the Commission's understanding of incremental cost seems hard to square with the language of the WSPP Agreement. Recall that WSPP defines incremental cost as the "forecasted expense incurred by the Seller *in providing* an additional increment of energy or capacity during a given hour" (emphasis added). The Commission's objection to Southern California's reading of the Agreement was that SP15 would only be its "incremental cost *once the sale to Mirant is consummated*." *Rehearing Order*, 108 FERC at P 14, p. 62,022 (emphasis added). In other words, the Commission faults Southern California for taking the projected sale into account, evidently reading the Agreement's "in providing" to mean "without providing." This linguistic twist might itself be grounds for reversal.

Once we try to set the language in a purposive context the Commission's approach appears still odder. Consider a seller with physical power-generating capacity, the type for which the WSPP Agreement was originally contemplated. See *Western Systems Power Pool I*, 55 FERC at 61,300. A seller with a portfolio of power-generating facilities can typically minimize the overall cost of providing any given total quantity by drawing on those facilities in increasing order of cost. Moreover, it seems plain that when contemplating an extra sale, the supplier must look at the facilities actually needed to make its *total* sales (the new one and those already contracted).

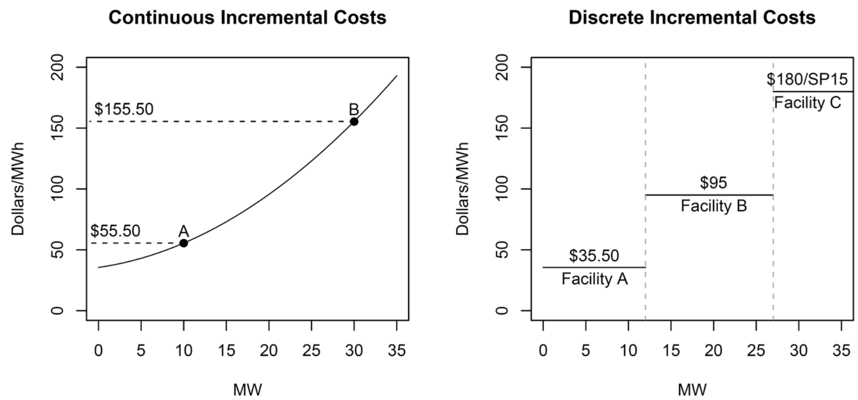

Figure 1: Illustration of Incremental Costs

This is laid out in Figure 1, with the left-hand panel depicting costs as continuously increasing. See Paul A. Samuelson & William D. Nordhaus, Economics 116-18 (16th ed. 1998). Better fitted to our case, and to the ordinary multi-plant electricity market, is the situation depicted in the right-hand panel, with cost levels coming in discrete segments. In that panel the seller owns three generating facilities, *A*, *B*, and *C*, with costs of $35.50/MWh, $95/MWh, and $180/MWh and capacities of producing 12 MW/h, 15 MW/h, and any foreseeably needed extra amount, respectively. If the seller at the outset has no commitments and then sells 10 MW of around-the-clock electricity to Buyer 1, costs are minimized if it produces at Facility *A*. The incremental cost of that sale—the cost of providing an additional MWh of electricity—would clearly be $35.50/MWh. As the seller increases its simultaneous sales, it moves to the right on the supply curve, progressively using more costly supplies. The right-hand panel plainly mirrors Southern California's situation in making its sale to Mirant. Given its retail load of roughly 12-17 MW, the Mirant sale would compel Southern California to draw not only on its $95/MWh supply from Mirant but also on its SP15 supply from IEP. The only difference, an inconsequential one, is that Facility

C now represents purchases at SP15. Although the spot price obviously varies, $180/MWh represents Mirant's prediction of the average SP15 price.

But the language of the WSPP Agreement leaves some ambiguity. One possibility is to treat as decisive the cost of the marginal unit (i.e., unit cost of raising production from (a) the contemplated total sales, minus one, to (b) the entire contemplated level of sales). In the context of trying to arrange for an efficient power market FERC has held that *all* sales at any given hour are to be at the cost of the marginal generator. See *Pacific Gas and Elec. Co. et al*, 77 FERC ¶ 61,204 at 61,806-07 (1996). Under certain plausible assumptions such a pricing rule (for all units sold) tends toward efficient allocation of resources. See ALFRED E. KAHN, THE ECONOMICS OF REGULATION 65-70 (2d ed. 1988). Cf. Ronald H. Coase, *The Marginal Cost Controversy*, 13 ECONOMICA, NEW SERIES 169 (1946) (arguing that where economies of scale have not been exhausted and therefore marginal cost is below average cost, the efficiency properties of marginal cost pricing are dubious). By analogy, the WSPP Agreement's cost-based ceiling for the April 2001 sale would be SP15.

A linguistically available alternative would be to read incremental cost to mean the average additional cost of raising sales from roughly 12-17 MW to roughly 27-32 MW. Kahn, for example, observes that incremental cost sometimes refers to "the *average* additional cost of a finite and possibly a large change in production or sales." KAHN, at 66. Under this view the ceiling dictated by the WSPP Agreement would be a weighted average of $95/MWh and SP15.

Other linguistically possible readings may exist, but the Commission's is not among them. In the *Rehearing Order* it rejected any consideration of the sale itself, and it adheres to that position on appeal, saying that the WSPP Agreement refers to "the last increment of energy sold based on the Seller's existing forecasted load at the time of sale, *without including the contemplated sale*." Respondent's Br. at 26 (emphasis added). At oral argument Commission counsel slightly modified the position, saying that the ceiling on a block of electricity would be the incremental cost of the first MW sold in the block. Oral Arg. Tape at 30:08. The distinction is immaterial here, as under both definitions the incremental cost would be \$95/MWh.

Obviously the Commission's view would prevent any sale where obtaining adequate supply would force the seller to draw on resources more costly than those already relied on. The Commission unsurprisingly offers no suggestion of what purpose such a rule might serve. Under the view offered by counsel at oral argument, the seller could make the sale possible by breaking it into smaller bites, creating a new bite at any breakpoint in cost level. The effect of this (assuming the Commission permitted it) would be the same as using the average incremental cost for the entire block.[1] But the Commission's rule was plainly to the contrary, as it read the Agreement as putting incremental cost at \$95/MWh pure and simple, with no allowance whatsoever for the necessary purchases from IEP at SP15.

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[1] Even under the view stated in the Commission's brief, a seller might conceivably be able to manipulate the rule so as to recover just under its average cost. By assuring that each sale bite included one unit at the next price up, it would set that as a base for its next sale.

There are doubtless other possible complications. Peak-hour energy is plainly more costly than off-peak, a distinction reflected in SP15. One might question Southern California's use of SP15 at off-peak hours when it could meet its entire demand with only its Dynegy and Mirant supplies. In *Western Systems Power Pool II*, however, the Commission seemed uninterested in such distinctions, saying that incremental cost "may be forecasted hourly, weekly, or monthly." 55 FERC at 62,718. Moreover, peaking power can be provided in multiple ways. Further, it may be that special difficulties are posed by extending ordinary readings of the WSPP Agreement from sellers with their own generating capacity to sellers such as Southern California that rely on forward contracts. But the Commission has made no such claims.

The Commission instead relied on two other arguments to support its conclusion that calculating incremental costs should exclude the sale in question. First, it found that Southern California "did not procure the energy it sold to Mirant from the spot market (or self-generate), but simply resold the energy it was contractually committed to purchase from Mirant," and that therefore the incremental cost was $95/MWh. See *Compliance Order*, 106 FERC at P 17, p. 62,198; Respondent's Br. 32-36. But the Commission does not explain how it reconciles this cost concept with the WSPP's definition of "*forecasted* expense . . . in providing an *additional* increment of energy or capacity" (emphases added). By attempting to attribute a fungible good to particular sources, the Commission effectively guts the meaning of incremental cost. For example, suppose that a seller owns Facilities *A* & *C* in the right-hand panel of Figure 1, generating a total of 14 MW per hour (12 MW on *A* and 2 MW on *C*). If the seller now acquires Facility *B*, the acquisition does not mean that the forecasted incremental cost in a sale of 15 MW (for a total commitment of 29 MW) would be $95/MWh, simply because the sale amount equals Facility *B*'s capacity. The forecasted cost of making total projected sales would have to reflect costs at Facility *C* (and under the pure marginal cost principle the cost at *C* would apply across the board).

Second, the Commission reasoned that the incremental cost could not have been SP15, because this would have meant that Southern California was simultaneously buying energy at SP15 while selling it at SP15 minus $20/MWh. See *Rehearing Order*, 108 FERC at P 14, p. 62,022; Respondent's Br. at 30. The argument is evidently that if incremental cost were SP15, a sale at below SP15 was necessarily unreasonable from Southern California's business perspective. This seems transparently wrong. Without the Mirant sale Southern California would not have come close to using the entire 27 MW capacity available to it in April under the Dynegy and Mirant baseload contracts. As a result it could improve its situation by making additional sales so long as the price was right. Selling 15 MW to Mirant at SP15 minus $20/MWh would, to be sure, necessitate procurement of some units in the spot market at SP15, but by no means enough to offset the revenue from the sale. By the same token, the $20/MWh discount made the transaction attractive to Mirant– which, because it had authority to sell at market rates, could count on being able to resell at SP15. Another alternative might have been for Southern California to sell a lesser amount– calibrated to dispose of all surplus energy but also to obviate the need to make any purchases at SP15. We have no idea whether any such sale would have been feasible, and the Commission never suggests its availability, or indeed, any reason why the existence of such an option would be relevant to the incremental cost determination.

Finding no rational explanation for the Commission's view that incremental cost under the WSPP Agreement for the April 2001 sale was $95/MWh, we must reverse.

On remand, if the Commission should find that incremental cost was below SP15 minus $20/MWh (a conclusion we neither approve nor preclude), it must address the issue of remedy. Southern California calls our attention to a number of decisions of this court indicating that the Commission should apply equitable principles in calculating refunds in these circumstances, a duty the Commission completely neglected here. See *Koch Gateway Pipeline Co. v. FERC*, 136 F.3d 810 (D.C. Cir. 1998); *Laclede Gas Co. v. FERC*, 997 F.2d 936 (D.C. Cir. 1993); *Gulf Power Co. v. FERC*, 983 F.2d 1095 (D.C. Cir. 1993); *Towns of Concord, Norwood & Wellesley v. FERC*, 955 F.2d 67 (D.C. Cir. 1992). The Commission responds that such cases are wholly inapplicable where, as its counsel argues, Southern California had made an "unauthorized and unreported sale of power in contravention of clear statutory and regulatory directives," which counsel characterizes as "brazen." Respondent's Br. at 40-41. Obviously any conclusion based on such reasoning will require re-examination.

The petition for review is granted and the case remanded for further action consistent with this opinion.

So ordered.