Trading Activities by Portland General Electric, PacifiCorp, and Idaho Power Company during the Western Electricity Crisis of 2000-01: Did They Violate Any Oregon Statutes, Rules, or Orders?

Oregon Public Utility Commission Staff

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On May 6, 2002, Enron Corporation turned over to the Federal Energy Regulatory Commission (FERC) three memos describing some of the company's trading strategies in California wholesale power markets in 2000. The trading strategies--with colorful names like Fat Boy, Ricochet, and Death Star--were designed to exploit loopholes in California's market design. Disclosure of the memos jump-started FERC's investigation of market abuses as a cause of the explosion of wholesale prices in West Coast markets in 2000-01. Since the memos surfaced, FERC has focused on who participated in the so-called Enron trading strategies and whether those participating violated any FERC requirements, such as codes and standards of conduct.

Our report examines trading in western markets in 2000-01 from a different perspective: it addresses whether the activities of Oregon's three investor-owned electric utilities--Portland General Electric (PGE), PacifiCorp, and Idaho Power Company--violated any Oregon statutes or Commission rules or orders. It is based on our review of the information available from the current FERC investigations, and it presents our preliminary conclusions and recommendations for Commission action.

This report is organized as follows. Section 1 describes the Enron trading strategies, why they are claimed to be illegal or improper, and what is known about their effect on the market. Section 2 summarizes ongoing FERC proceedings and criminal and civil investigations into trading practices and market prices during the 2000-01 crisis. Section 3 discusses the evidence from these cases about the involvement of PGE, PacifiCorp, and Idaho Power in suspect trading activities. Section 4 examines whether the utilities violated any of the laws, rules, or orders administered or issued by the Commission. Finally, Section 5 presents our recommendations for Commission action.

1. The Enron Trading Strategies

The Enron memos discuss ten trading strategies, and several variants of them have been identified since the memos were released. This section describes the strategies, why they are allegedly illegal or improper, and what is known about their effect on market prices.[1]

We divide the trading strategies into three categories: inc-ing load, arbitrage, and congestion payment strategies.

Inc-ing load

This strategy, called Fat Boy in the Enron memos, was a response to the common practice by California's investor-owned utilities of significantly underscheduling load, i.e., understating expected need, in the day-ahead market operated by the California Power Exchange (PX). The California utilities did this because any load not scheduled in the day-ahead market would be served in the real-time market by the California Independent System Operator (ISO), which had tighter price caps than the PX and lower expected prices. The utilities' strategy of underscheduling load in the day-ahead market meant that the ISO had to find a way to serve the excess load when it appeared in the real-time market. The ISO met the excess load by calling on supplemental energy offered by suppliers or by offsetting it with unexpected generation.

[1] This section is based primarily on the Enron memos and on: Falk, Jonathan, "Substituting Outrage for Thought: The Enron 'Smoking Gun' Memos," The Electricity Journal, August/September, 2002; Kee, Edward, "Direct Testimony Before the Federal Energy Regulatory Commission," Docket No. EL02-26-000 et al., August 27, 2002; McCullough, Robert, Direct Testimony Before the Federal Energy Regulatory Commission," Docket No. EL02-26-000 et al., July 2, 2002; McCullough, Robert, "Congestion Manipulation in ISO California," Memorandum, McCullough Research, June 5, 2002; Chandley, John, "The Enron Trading Practices: How They Worked, Why They Occurred, What They Teach Us," Presentation at EUCI Conference on Market Design, Atlanta, GA, September 23-24, 2002, California ISO, "Analysis of Trading and Scheduling Strategies Described in Enron Memos," October 4, 2002, and FERC Staff, "Final Report on Price Manipulation in Western Markets," Docket No. PA02-2-000, March, 2003.

Enron and other suppliers quickly recognized the California utilities' strategy and saw an opportunity to serve the excess load in the real-time market. Enron used Fat Boy as a way to send additional generation to the real-time market. It overscheduled ("inc-ed") load, with matching generation, in the day-ahead market so that it would have surplus generation available in the real-time market. Enron's expectation was that the ISO would use the excess generation to serve the excess load that appeared in the real-time market.

Fat Boy depended on Enron purposefully submitting false schedules to the PX. This deception was clearly improper and may have violated the ISO tariff and constituted unjust and unreasonable practices under the Federal Power Act.[2] However, because Fat Boy offset the effect of underscheduling by the California utilities, the strategy apparently had little adverse impact on western markets in 2000-01 and may even have reduced prices.[3]

Arbitrage

Most of these strategies took advantage of different prices for the same product. One obtained a higher price by misrepresenting the product sold.

<u>Export of California Power</u> was a strategy to buy power in the California market at or below the price cap and then resell it outside the state at a higher (uncapped) price. It had the potential to increase prices in California and reduce them in the export markets.

[2] FERC investigative staff concluded in its Final Report in Docket No. PA02-2-000 that almost all of the Enron strategies violated the antigaming or anomalous market behavior provisions of the ISO and PX tariffs. FERC trial staff in Docket No. EL02-114-000 claimed that other allegedly false schedules submitted by Enron were unjust and unreasonable practices under Sections 205 and 206 of the Federal Power Act (Commission Staff's Revised Statement of Asserted Violations, Item No. II.A, December 10, 2002).
[3] Chandley, p. 14.

Ricochet took advantage of the fact that imports into California could be priced above the caps. Enron would buy power in the California day-ahead market and sell it to an entity outside the state. It would then repurchase the power from the out-of-state entity and sell the imported power in the California real-time market at a price above the cap. Enron would make money if the real-time price paid for out-of-state supplies exceeded the day-ahead purchase price and the real-time price for in-state supplies. The success of the strategy depended on there being excess demand in the real-time market, which often occurred because California utilities underscheduled load in the day-ahead market (as discussed above). Profitable execution of Ricochet raised overall market prices in California, because it scheduled power transfers simply to obtain a higher price.

Get Shorty involved selling ancillary services in the day-ahead market and covering the obligation with a purchase in the real-time market.[4] This strategy was profitable when the day-ahead sale price exceeded the real-time purchase price. Since Enron was required to identify the source of the ancillary services (e.g., a specific generation unit) when it made the sale in the day-ahead market, it may have submitted false information to the ISO. Selling ancillary services without having the physical assets to provide them may have posed a threat to system reliability.

Non-firm as Firm was a strategy to avoid providing or paying for operating reserves. Operating reserves represent generating capacity that can be called into service quickly when other plants experience unexpected outages. Suppliers selling non-firm energy in the California market were charged by the ISO for the costs of procuring operating reserves. Those selling firm energy were presumed to be providing their own reserves and were not charged. The Non-firm as Firm strategy involved buying non-firm power outside of California and then selling it in the state and representing it as firm to the ISO. The strategy was profitable because it avoided the cost of obtaining operating reserves. The ISO now requires verification that imports said to be firm actually are firm.

[4] The practice of making a forward sale and then meeting the commitment with a purchase in the real-time market is commonly known as selling short.

Except for Export of California Power, these arbitrage strategies may have violated the ISO and PX tariffs and been unjust and unreasonable practices under the Federal Power Act. According to FERC staff, Ricochet was not legitimate arbitrage, and Get Shorty and Non-firm as Firm were illegal gaming because they were based on submitting false information to the ISO.

Congestion payment strategies

These strategies took advantage of the ISO's rules for paying for relief of transmission paths that were scheduled to their full capacity. Users could get paid for reducing flows in the direction of the congestion or by increasing flows in the opposite direction. Several of the Enron strategies were designed to collect these payments from the ISO without actually relieving any congestion (i.e., falsely relieving congestion), while at least one other strategy created phony congestion and then relieved it (i.e., relieving false congestion).

The Enron memos describe Death Star as a strategy that falsely relieved congestion. Enron would schedule a northbound counterflow on congested paths in California to collect congestion relief payments from the ISO, while simultaneously scheduling a return southbound flow on paths outside the control of the ISO. With the same amount of power scheduled to flow north and then south back to the point of origin, power did not actually flow and no congestion was relieved.[5] Death Star was profitable as long as the congestion relief payments from the ISO exceeded the cost of the scheduled transmission.

Three other strategies falsely relieved congestion. Non-firm Export involved scheduling a counterflow out of the ISO's control area, collecting the congestion relief payment, and then withdrawing the schedule. The ISO prohibited Non-firm Export in a market notice

[5] As discussed in Section 3, PGE argues that these transactions did in fact relieve congestion even though power did not flow.

issued July 21, 2000. Scheduling Energy to Collect the Congestion Charge II worked by scheduling a counterflow on a congested path, receiving the congestion relief payment, and then not delivering the energy in real time. The ISO would charge the trader the cost of supplying the missing power. This strategy was profitable if the congestion relief payment was more than the replacement energy cost, which could occur because the price for replacement energy in the ISO real-time market was capped, but the congestion relief payment was not. Wheel Out exploited a loophole allowing market participants to schedule transmission on lines that were out of service. Enron would schedule an export on an out-of-service line, and then if the export proved to be a counterflow that relieved congestion in the hour-ahead market, it would earn a congestion relief payment. Since the line was out-of-service, the ISO would cancel the schedule in real time, but Enron would keep the congestion relief payment. The ISO eventually put an end to Wheel Out by refusing to accept schedules across lines that were not in service.

Load shift was a plan to relieve false congestion. Enron would intentionally underschedule load in one zone in California and overschedule load in another, thereby increasing congestion in the direction of the overscheduled zone. The relief occurred when Enron later adjusted the two schedules to reflect actual expected loads. The adjustment created a counterflow toward the underscheduled zone, earning Enron a congestion relief payment from the ISO. Enron needed to have firm transmission rights (FTRs) in the direction of the overscheduled zone to cover its exposure to ISO congestion charges, but any of its FTRs that were not used may have earned artificially high FTR payments from the ISO. FERC staff found that this strategy was not very successful, in that Enron was not able to affect the price paid for congestion management.

As they are described in the Enron memos, these congestion payment strategies were clearly deceptive and therefore may have violated the ISO tariff and constituted unjust and unreasonable practices under the Federal Power Act. However, since congestion relief payments are not included in reported market prices and price indexes (which are used to price many other transactions), the strategies probably had little impact on energy prices in western markets in 2000-01.

2. Investigations of the Western Electricity Crisis

Several federal and state authorities are investigating trading activity and pricing in western markets in 2000-01. Some cases focus on whether any trading practices were used to game or manipulate the market. Others address whether market prices were in and of themselves unjust or unreasonable. This section summarizes the major proceedings.

FERC proceedings

<u>Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices</u>

In an order issued on February 13, 2002, FERC directed its staff to investigate whether any entity manipulated short-term prices for electricity or natural gas or otherwise exercised undue influence over wholesale electric prices in western markets in the period beginning January 1, 2000.[6] On May 8, 2002, right after the Enron memos came to light, the FERC staff asked companies who sold electricity or ancillary services in wholesale markets in the West during 2000-01 to admit or deny engaging in the Enron trading strategies. PGE, PacifiCorp, and Idaho Power all responded. FERC, however, concluded that PGE and three other companies did not provide complete and accurate responses to the May 8 request and, on June 4, 2002, directed the four to show cause why their market-based rate authority should not be revoked. PGE answered on June 14, 2002, and later provided two supplemental responses.

Based on its staff's findings, FERC opened a separate investigation into possible misconduct by PGE and Enron Power Marketing, Inc. (EPMI) on August 13, 2002.[7] FERC cited preliminary evidence of possible violations by PGE and EPMI of their codes

[6] The proceeding is docketed as PA02-2-000.
[7] Docket No. EL02-114-000

of conduct and FERC's standards of conduct. Codes of conduct govern the relationship between a public utility and an affiliated power marketer, while standards of conduct require that a transmission provider not discriminate in favor of its merchant side or its marketing affiliates at the expense of other users. FERC identified refunds and revocation of market-based rate authority as possible remedies for any demonstrated misconduct.

At the same time, FERC initiated separate proceedings on trading activity by Avista and El Paso Electric. The Avista case focuses on the company's role as an intermediary in Death Star transactions with Enron and PGE. In the other case, FERC alleges that El Paso gave preferential transmission access and control of its trading desk to Enron. FERC trial staff has reached settlement with both companies (but not other parties in the proceedings). Under the terms of its settlement, Avista would agree to certain record keeping and training requirements but would be cleared of charges that it knowingly participated in any improper trading strategies or failed to provide relevant information in the Fact-Finding Investigation. El Paso would refund $14 million and give up its market-based rate authority until the end of 2004 in order to settle the claims against it.

FERC trial staff submitted direct testimony in PGE's case on December 10, 2002. Citing the company's role in Death Star transactions and its failure to post deals with Enron properly (discussed in Section 3, below), FERC staff concluded that PGE violated the code of conduct and other provisions in its market-based rate tariff and engaged in practices that are unjust and unreasonable under Sections 205 and 206 of the Federal Power Act. FERC staff recommended that PGE's market-based rate authority be revoked for two years and that the company revise its training, monitoring and other procedures to ensure that the violations do not occur again. In its direct testimony, filed on February 24, 2003, PGE explained that the transactions challenged by FERC staff appeared to the company to be legitimate and of a type familiar to utilities in the Northwest. PGE argued that Death Star transactions actually relieved congestion and benefited electricity customers in California. The company also stated that most of its posting errors should not be considered errors or tariff violations at all, because the posting requirement is vague and the deals with Enron were still visible and available to other market participants.

FERC staff is scheduled to file its rebuttal testimony in PGE's case on May 12, 2003. PGE is discussing settlement of the case with FERC staff and other parties to the proceeding. The other parties include the OPUC, the Industrial Customers of Northwest Utilities, Blue Heron Paper Company, the City of Tacoma, and several California agencies and utilities.

On January 31, 2003, FERC approved a settlement between its staff and Reliant Energy in the Fact-Finding Investigation. The settlement requires Reliant to pay $13.8 million to PX customers because the company limited the amount of power it offered to the PX for delivery on June 21-22, 2000, in an attempt to increase prices.

On March 26, 2003, FERC investigative staff issued its Final Report in the Fact-Finding Investigation. The staff found that most of the Enron trading strategies violated the antigaming or anomalous market behavior provisions of the Market Monitoring and Information Protocol (MMIP) in the FERC-approved ISO and PX tariffs.[8] "Gaming" means taking unfair advantage of ISO or PX rules and procedures, or system conditions, to the detriment of market efficiency and consumers. It also includes actions that make the system vulnerable to price manipulation. Market behavior is "anomalous" if it is significantly different from normal behavior in competitive markets or leads to unusual or unexplained market outcomes. The staff recommended that 38 utilities and marketers (including PGE, PacifiCorp, and Idaho Power) identified by the ISO as participating in the suspect trading activities be directed to show cause why they should not be found in violation of the tariffs and required to give back all the related profits.[9]

[8] FERC staff stated that the following strategies violated the antigaming or anomalous market behavior provisions of the MMIP: Non-firm Export, Death Star, Wheel Out, Load Shift, Get Shorty, Non-firm as Firm, Ricochet and Fat Boy.

[9] In a report issued on October 4, 2002 ("Analysis of Trading and Scheduling Strategies Described in Enron Memos") and supplemented on January 17, 2003, the ISO assessed the extent and impact of participation in the various Enron strategies. The ISO described how it screened its transactions data to

FERC staff also found that nine companies (including Idaho Power) submitted bids to the ISO between May and October 2000 that exceeded $250 per megawatt-hour (MWh), well beyond the cost of generation. The staff recommended that the companies be required to show cause why they should not be found to have engaged in economic withholding or inflated bidding in violation of the ISO tariff and required to give back unjust profits. FERC invited comment on its staff's interpretation of the MMIP provisions, and it has not yet issued the requested show cause orders.

Other FERC staff recommendations in the Final Report and FERC's response are discussed below.

Refund cases

FERC is considering refunds on transactions during the western electricity crisis in two proceedings, known as the California and Northwest refund cases. The California case opened with a complaint filed by San Diego Gas & Electric on August 2, 2000. On November 1, 2000, FERC concluded that the market structure and rules for wholesale electricity sales in California were seriously flawed and contributed to unjust and unreasonable rates. After attempts to settle the case were unsuccessful, FERC ordered evidentiary hearings on the use of a mitigated market clearing price (MMCP) to determine refunds. The MMCP is based on the marginal cost of the last unit dispatched to meet load. The order also established a refund period beginning October 2, 2000 (sixty days after San Diego's filing) and ending June 20, 2001 (when price caps were imposed).

On December 12, 2002, the FERC administrative law judge (ALJ) in the California case issued a proposed finding for refunds of about $1.8 billion to the California ISO and PX. This amount would be netted against the roughly $3 billion still owed to suppliers by the ISO and PX. It is substantially less than the $8.9 billion sought by California parties.

identify trades or schedules of each type, but it noted that in some cases its methods were imperfect (e.g., incorrectly classifying some transactions as Death Star deals, but overlooking others).

FERC initiated the Northwest refund case in an order issued on July 25, 2001.[10] FERC directed the ALJ for the case to determine whether rates for spot market sales in the region were unjust and unreasonable during the potential refund period of December 25, 2000, through June 20, 2001, and it set an expedited schedule for the proceeding. On September 24, 2001, the ALJ concluded that spot market prices in the Northwest were not unjust and unreasonable during the refund period and recommended that the case be closed.

On August 21, 2002, the Ninth Circuit Court of Appeals directed FERC to allow parties to submit evidence on market manipulation in the California refund case. FERC responded on November 20, 2002, with an order giving parties until February 28, 2003 (later extended to March 3, 2003) to conduct discovery, introduce evidence, and recommend findings with respect to market manipulation. On December 19, 2002, it issued a similar order, with the same deadline, in the Northwest refund case. On March 3, 2003, refund proponents submitted filings in the two cases that 1) summarized evidence of market manipulation from other FERC cases, 2) offered new evidence of such activity, and 3) charged specific suppliers and utilities with engaging in abusive practices. Other parties responded on March 17, 2003.

In its Final Report in the Fact-Finding Investigation, FERC staff concluded that spot gas prices in California were artificially high during the refund period, due in part to manipulation of gas price indices and other market abuses. On March 26, 2003, FERC adopted its staff's recommendation to use producing area prices plus transportation as a proxy for competitive gas prices in computing the MMCP in the California refund case. In calculating refunds, however, generators would be compensated for their actual gas expenses. Replacing published natural gas prices with the lower proxy prices is expected to increase the refund amount by about $1.5 billion. FERC staff also concluded that spot prices in the Northwest during the refund period were excessive, i.e., not based on cost, and recommended that the finding be referred to the ALJ in the

[10] The docket for the case (EL01-10-000) was opened on October 26, 2000, when Puget Sound Energy petitioned FERC to cap wholesale prices for energy and capacity in the Northwest. As a result, the

Northwest refund case for consideration. At its March 26, 2003 meeting, FERC indicated that any refunds in the Northwest case will be limited to spot purchases (30 days or less in duration).

The OPUC has been an active participant in the Northwest refund case. The Commission disagreed with the ALJ's finding that spot market prices in the region were not unjust and unreasonable during the refund period. The Commission, however, opposed refunds as a general remedy, arguing that only those who manipulated the market or otherwise exercised market power at the expense of others should be required to make refunds. Ordering refunds by all parties who sold in the spot market at more than some reference price would be inequitable, because it would favor buyers who relied on the spot market over those who purchased in the forward market and because some market participants are not subject to FERC's jurisdiction.

The Commission also filed comments in the California refund case outlining principles for any refunds ordered. The principles are that: past due bills for wholesale purchases should be paid before refunds occur; refunds should be ordered only for utilities that were substantially harmed, in percentage terms; refunds should cover market index transactions of any term and bilateral deals with terms up to thirty days; refunds should be limited to a specific time period for the entire western market; sellers should not be required to refund more than their net margins on sales; and regulated Oregon utilities with an obligation to serve should not be required to make refunds, because they do not have market power and they resell power they purchased in advance to serve their retail customers only when it turns out to be surplus to customers' needs.

<u>Contract cases</u>

Once wholesale prices fell in mid-2001, many forward contracts signed during the western electricity crisis looked uneconomic. Some purchasers filed complaints asking

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Northwest refund case is also known as the Puget investigation, although Puget itself opposes refunds.

FERC to modify the contracts. In setting the complaints for hearing, FERC stated that the petitioners had a heavy burden of proving that the agreements should be revised.

Two of the contract cases involve Northwest utilities. Snohomish County PUD filed a complaint against Morgan Stanley Capital Group that was consolidated with several others. On December 19, 2002, the FERC ALJ for the proceeding issued an initial decision denying the requests for contract modification. The ALJ ruled that the standard for FERC to reform a contract is that it is contrary to the public interest, i.e., that the contract would bankrupt the company, cause undue discrimination, or impose an excessive burden on its customers. The judge rejected the claim that a lesser standard, that the contract rates are not just and reasonable, applies. The ALJ concluded that, under the public interest test, the petitioners failed to show that faults in the ISO and PX spot markets adversely affected the long-term markets.

On May 2, 2002, PacifiCorp filed complaints against four suppliers, requesting modification of contracts for delivery of energy during the three months beginning July 1, 2002. PacifiCorp argued that the contract rates were not just and reasonable and/or contrary to the public interest as a result of market failure in California and the imposition of price caps after the contracts were signed. The caps were lower than the contract rates and remained in effect through the term of the contracts. Therefore, unlike the longer-term deals at issue in the other contract cases, PacifiCorp's contracts were necessarily out-of-market. On February 26, 2003, however, the FERC ALJ issued an initial decision rejecting PacifiCorp's request, finding that the company did not meet the public interest standard for modifying the contracts. On March 13, 2003, PacifiCorp asked FERC to reopen the case to consider the evidence from the Fact-Finding Investigation that Reliant (one of the four counterparties) withheld power to increase prices. On April 17, 2003, the OPUC sent FERC a letter supporting refunds in the PacifiCorp dockets. Noting the link between California spot market prices and forward market prices established by FERC staff in the Fact-Finding Investigation, the OPUC argued that the PacifiCorp contracts should be reformed because FERC ordered refunds in the California spot market because the market was dysfunctional and was manipulated.

Finally, in a complaint filed on February 25, 2002, the California Public Utilities Commission and Electricity Oversight Board challenged 32 of the contracts signed by the state during the electricity crisis. They claimed that the contract rates exceed just and reasonable levels by about $14 billion. Since the complaint was filed, the state has reached settlement on 21 of the contracts, saving $5.1 billion.

FERC staff concluded in its Final Report in the Fact-Finding Investigation that market abuses caused spot market prices to be higher than justified by supply and demand conditions during the western electricity crisis and that spot market prices influenced forward prices negotiated during the crisis. The staff recommended that its analysis be considered in the contract cases if the just and reasonable standard applies. At its March 26, 2003 meeting, however, FERC signaled that it will apply the stricter public interest standard and that it will not abrogate contracts with terms of more than 30 days that were signed during the crisis.

Criminal and civil proceedings

On October 17, 2002, Tim Belden, the former head of western energy trading for Enron, pleaded guilty to one count of conspiracy to commit wire fraud. Belden admitted to submitting false information to the ISO and PX and implementing other fraudulent schemes in order to boost Enron's revenues. The plea came in connection with a continuing probe into manipulation of California's energy markets being conducted by the U.S. Attorney's Office in San Francisco, the U.S. Department of Justice, and the Federal Bureau of Investigation. Belden is apparently cooperating with the investigation and may implicate other individuals and companies. The U.S. Attorney has kept Belden under wraps since he pleaded guilty, and we have not been able to question him. On February 4, 2003, Jeffrey Richter, who was head of short-term energy trading in

California for Enron and reported to Belden, pleaded guilty to wire fraud and lying to federal investigators. Richter admitted involvement in designing and running the Get Shorty and Load Shift strategies.

On another front, the attorneys general of California, Oregon, and Washington began a joint investigation into possible price manipulation and antitrust violations in western power markets in early 2001. On November 11, 2002, the three states announced a settlement with the Williams Companies. Williams will pay Oregon $15 million over three years and cooperate in the states' scrutiny of the trading practices of other market participants, and Oregon will drop its investigation of Williams. On March 21, 2003, the three states, along with Nevada and other parties, announced an agreement in principle with El Paso Corporation, under which Oregon will receive $17 million in damages. The OPUC and the Oregon Office of Energy assisted the Oregon Department of Justice in identifying possible misconduct and estimating the harm to Oregon consumers.

3. PGE, PacifiCorp, and Idaho Power Trading Activity

This section describes the involvement of PGE, PacifiCorp, and Idaho Power in questionable trading activities during the western electricity crisis. It is based largely on information developed in the FERC investigations. We also requested information from PGE on several occasions, and the company cooperated in responding. We requested only limited information from PacifiCorp or Idaho Power in preparing this report.

PGE

In its response to the May 8, 2002 data request in FERC's Fact-Finding Investigation, PGE identified 17 days during April, May, and June of 2000 when it may have been used as an intermediary in Death Star transactions. PGE has reported separately that it may have failed to properly post a large majority of its transactions with Enron in 1999-2001.

PGE also stated in its response to the May 8 request that for more than 30 years it has purchased power from California to meet its retail customers' expected needs and then resold any surplus in the wholesale market. In late 2000 and early 2001 in particular, PGE bought power in the day-ahead market in California to insure it would have enough power to serve its customers and to avoid the greater price volatility of the real-time market. The purchases became part of the company's resource portfolio, and any subsequent resale of power in excess of its actual needs cannot be traced to a specific source. PGE also stated that others may have used its "parking" service to engage in Ricochet deals.[11] PGE later found that Enron used its parking service only once during the western electricity crisis and that the transaction was not a Ricochet.

[11] "Parking" is a service that allows a marketer to buy power in the day-ahead market for later resale in the real-time market. It is available from several other utilities in the western market.

In preparing its response to the May 8 FERC request, PGE interviewed employees involved in trading activities and directed them to gather relevant documents. The company also searched computer and e-mail files using keywords describing the Enron trading strategies. The company, however, does not have complete electronic files before December 11, 2000 because the tapes for backing up the data were periodically overwritten until then. PGE identified the 17 days of potential Death Star trades through a computer search of trading records based on details of the transaction recalled by Bill Casey, a manager on the trading floor. The company later conducted a more detailed examination of its transmission and trading records (by searching for hours in which the necessary steps for a Death Star transaction occurred on PGE's system and then reviewing trading in those hours in detail) and reduced the count to 15 days.

During the course of the FERC investigations, PGE provided transcripts of trader telephone conversations occurring on more than 50 days in 2000-01. PGE's traders ordinarily arrange transactions with others over the phone, and the company has trading floor voice recordings for all of 2000-01 except for a few hours in May and June of 2001, when the recording system failed. The transcripts do not indicate that PGE participated in any of the Enron trading strategies beyond the 15 days of potential Death Star transactions. FERC trial staff asked for all the recordings of conversations between PGE's marketing and transmission traders but later narrowed its request to 20 specific days. FERC staff listened to the recordings and found no evidence of PGE involvement in any of the other Enron trading strategies.

In early December 2002, several PGE real-time and transmission traders were deposed (in EL02-114-000) at the request of the City of Tacoma. The OPUC participated in the questioning. Most of the traders knew very little about Death Star and the other Enron trading strategies. They appear to focus on getting the job done (balancing loads and resources each hour or scheduling transmission) and then moving on to the next hour or the next transmission request. The depositions did not reveal any significant new information about PGE's involvement in Death Star or other Enron strategies.

On March 26, 2003, FERC staff for the Fact-Finding Investigation recommended that PGE and others identified as participating in Enron trading strategies be directed to show why they should not be found to have violated the antigaming and anomalous market behavior provisions of the ISO and PX tariffs and required to return the related profits. FERC staff claimed that PGE was involved in potential Ricochet deals and referenced ISO findings that the company was engaged in the Get Shorty strategy (selling ancillary services short).[12] FERC, however, has not yet issued the show cause orders requested by its staff.

Death Star

As discussed briefly in Section 1, Death Star was a strategy to collect congestion relief payments without adjusting loads or resources. Enron scheduled power to flow north on transmission paths in California that were congested north-to-south and collected congestion relief payments from the ISO, while at the same time scheduling southbound flows on paths outside the control of the ISO. In the transactions involving PGE, power was scheduled to flow in a loop, entering the transmission system in southern California, flowing north to PGE's system and then back south, leaving the system in southern California. With the same amount of power scheduled to flow north and south, no additional power was generated or consumed, and no power actually flowed. Since no power flowed, FERC staff has concluded that no congestion was relieved.

As noted above, PGE identified 15 days during April, May, and June of 2000 when it may have been used as an intermediary in Death Star transactions.[13] The specific steps in most of the transactions are shown in Table 1.

[12] PGE, however, was not very active in selling ancillary services short. The ISO reported that PGE had a net loss of $250 (on $1,095 in gains and $1,345 in losses).

[13] The company reduced its original estimate of 17 days because the southbound flow was scheduled with the ISO on two of the days. It is not able to verify the southbound flow on one other day but cannot rule it out as a Death Star transaction.

Table 1: The Death Star Transactions

Northbound

1. EPMI schedules transmission from Mead to the California-Oregon Border (COB) on congested paths in order to collect relief payments
2. EPMI sells to Washington Water Power (WWP or Avista) at COB for $x
3. WWP sells to PGE at COB for $x
4. PGE schedules transmission from COB to its control area (PGE System) using its northbound AC Intertie rights
5. PGE sells to WWP at PGE System for $x
6. WWP sells to EPMI at PGE System for $x+$1
7. EPMI sells to PGE at PGE System at Mid-Columbia (Mid-C) index

Southbound

8. PGE schedules transmission to John Day using its Integration of Resources (IR) contract with Bonneville
9. PGE sells to EPMI at John Day at Mid-C index plus a premium
10. EPMI schedules transmission to COB, on southbound AC Intertie rights previously acquired from PGE
11. EPMI schedules transmission from COB to Mead on paths not controlled by the ISO

PGE does not concede that any of the transactions were Death Star deals because its records do not show the northbound leg in California (Step 1). FERC staff concluded that they were part of a Death Star strategy, based on 1) internal Enron documents describing how to run Death Star, and 2) a matching of the PGE and EPMI transaction databases and comments in the EPMI logs identifying at least some of the deals with PGE as Death Star.

EPMI could not implement Death Star by simply scheduling transmission north to COB and then south on a path outside the ISO's control area (i.e., skipping a northwest loop like the one in Steps 2-10) because the ISO prohibited this type of flow reversal at COB. PGE provided scheduling and control area services EPMI needed to side step this prohibition on flow reversals at COB. First, PGE scheduled transmission north from COB to its system (Step 4). PGE's control area became the "sink" on the northbound leg of Death Star. In transmission scheduling, the "sink" is the utility control area at the end of a transmission path, where the power leaves the transmission system. Second, PGE scheduled transmission from its own generators to the John Day substation (Step 8). PGE became the "source" on the southbound leg of Death Star. The "source" is the control area at the beginning of a transmission path, where power enters the transmission grid. In effect, PGE took power with an ISO source from EPMI and returned it to EPMI with a PGE source. This change in source tag helped EPMI get around the ISO's ban on flow reversals at COB. Any other Northwest utility able to sink the power could have provided the services EPMI needed.

PGE's compensation for providing these services was minimal. In most instances, the premium in the sale price at John Day (Step 9) was $0.90 per MWh, and less than 2,500 MWh were sold. The ISO has estimated that Enron collected about $484,000 in congestion relief payments from this type of Death Star transaction in 1998-2001, but we do not know how much Enron made on the deals involving PGE.[14]

The last Death Star transaction with PGE occurred on June 6, 2000. EPMI may have halted the activity because PGE told its own traders (and presumably, EPMI) on June 6 that it would impose higher wheeling costs on EPMI because Bonneville was planning to charge PGE more for transmission from COB to PGE's system. The additional charges may have made running Death Star through PGE uneconomic for EPMI.

PGE has consistently stated that it did not knowingly participate in any deceptive or misleading trading strategies. It asserts that it was unaware that EPMI was executing a

[14] California ISO, "Analysis of Trading and Scheduling Strategies Described in Enron Memos," October 4, 2002. The report also states that Enron earned about $2.8 million in congestion payments from "circular scheduling" overall. Death Star is a specific type of circular schedule. In the Addendum issued on

Death Star strategy because it did not know about the Mead to COB flow that initiated the cycle shown in Table 1. PGE says that the portion of the deal its traders saw appeared to be legitimate and was attractive because it allowed PGE to earn a fee for a buy-sell transaction that did not require it to assume any market risk.

The company has also claimed that the Death Star transactions did not harm the market but instead actually relieved congestion and reduced costs to California consumers. According to PGE, when the ISO's lines were congested north-to-south, an EPMI counterflow (Step 1) of, say, 10 megawatts (MW), enabled the ISO to schedule another 10 MW south. EPMI was able to schedule the counterflow even though it did not have a 10 MW load to serve in the north because it used its north-to-south transmission rights on lines outside the ISO's control to create a circular path with no power actually flowing. In effect, EPMI used its non-ISO rights to give the ISO an equivalent amount of additional north-to-south capacity, i.e., to relieve congestion. The additional transfer capability allowed low-cost generation in the north to displace high-cost generation in the south, thereby reducing overall costs in California.

The ISO does not know about available transmission capacity on non-ISO lines until 40 minutes before the hour. Before that time, the ISO may see congestion on its lines even though the entire system has additional transfer capability. PGE concedes that the congestion Death Star relieved on the ISO's lines on a preschedule basis would have been relieved anyway in real time (when the available transmission on non-ISO lines became visible to the ISO), but it argues that making the capacity available in advance reduced uncertainty for the ISO.

FERC investigative staff nevertheless considers Death Star to be a violation of the antigaming provisions of the MMIP provisions of the ISO and PX tariffs. In its Final Report in the Fact-Finding Investigation, the staff characterizes Death Star as an "imaginary" transaction designed to capture congestion relief payments by "fooling" the

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January 17, 2003, the ISO upped the congestion payments to Enron from circular scheduling to $5.3 million but did not address the $484,000 attributed to Death Star in the initial report.

ISO's congestion management computer program. The Final Report does not address whether Death Star actually relieved congestion.

Posting errors

Under the terms of its market-based rate authority, when PGE offers to buy from or sell to an affiliated power marketer, it must simultaneously make the same offer to all others on an electronic bulletin board. PGE is also required to post the actual price charged when an affiliate accepts an offer. The purpose of the posting requirement is to ensure that PGE does not favor its affiliates by buying at a higher price or selling at a lower price than it is willing to offer others.

After FERC opened its Fact-Finding Investigation on February 8, 2002, PGE began to review its transactions with affiliates and discovered a large number of errors in posting transactions with EPMI.[15] From 1999 through 2001, PGE made posting errors in 65 percent of its transactions with EPMI (1,290 out of 1,979 total trades). Trading with EPMI during this time accounted for 11 percent of PGE's wholesale sales revenues and 10 percent of its wholesale purchase costs. Almost all of the trades were buy-sell transactions, in which PGE bought power from EPMI at one location and simultaneously sold the same amount of power back at another location at a small profit. EPMI was in effect moving its power from one point to another to advance or complete a sale (although PGE often accomplished the transfer by cutting the power received from its own resources at the buy location and increasing it at the sell location, rather than actually scheduling transmission of the power between the two points). EPMI accounted for the vast majority of PGE's buy-sell transactions, but PGE claims that other utilities (such as Chelan PUD) offered the same service.

Most of the errors involved a difference in what was offered and what was accepted (with both the offer and the acceptance posted). PGE usually offered a flat product (the

[15] PGE self-reported its findings to FERC on April 15, 2002 (term transactions, which are a month or more in duration) and on August 1, 2002 (daily and hourly trades).

same amount of power in all hours), but in these cases EPMI accepted and received a shaped product (different amounts of power in on- and off-peak hours).[16] In other cases, PGE failed to post the offer to EPMI, erred in posting EPMI's acceptance, was unable to confirm it had posted an offer or acceptance, or made miscellaneous or multiple posting mistakes.

FERC trial staff has concluded that PGE violated its market-based rate authority by failing to post its transactions with EPMI properly. PGE claims that the posting requirement in its FERC tariff is vague and subject to interpretation and that a difference between the posted offer and acceptance (which accounted for most of the errors) shouldn't be considered an error at all because other parties knew from the posted offer or acceptance what PGE was willing to buy or sell. Furthermore, PGE argues that EPMI did not get an unfair advantage from the posting errors because EPMI could have obtained the same service from others at lower cost. PGE also states that the errors had no effect on market prices because almost all the deals were priced at index (i.e., at posted market prices).

PacifiCorp

In its response to FERC's May 8, 2002 "admit or deny" request, PacifiCorp admitted to Export of California Power. The company bought energy in the California market in 2000-01 mainly to serve its retail customers but also to resell at a higher price outside California. PacifiCorp noted that it has historically purchased energy from California in order to serve its customers and balance its system.

In its response to FERC, PacifiCorp denied initiating any Ricochet trades but stated that it was an intermediary in Ricochet transactions with Enron. During a five-month period starting in July 2000, PacifiCorp entered into 767 buy-sell transactions with EPMI,

[16] PGE asserts that all parties knew that PGE's posting of a flat product meant it would accept shaped deals.

Aquila, Sempra, and Williams. These deals involved a total of 40,376 MWh, less than one percent of the company's wholesale purchases or sales for 2000. PacifiCorp stated that the trades at first looked the same as other buy-sell transactions using its transmission system. As the number of transactions increased, however, the company became increasingly aware that they were limited to a single point of delivery, and it grew concerned that the deals were a form of megawatt laundering (another term for Ricochet). As a result, PacifiCorp stopped doing these buy-sell deals in mid-November 2000.

PacifiCorp also denied engaging in a Death Star trading strategy but noted that it circulated energy in a similar manner at the ISO's request to relieve congestion on the ISO's lines. The ISO has reported that PacifiCorp collected about $250,000 in congestion relief payments in 1998-2002 (with almost 60 percent of the payments in 1998). The company stated that these circulating trades were not Death Star transactions because in all circumstances energy was actually put onto and taken off the ISO grid.

PacifiCorp also described certain transactions involving the use of its transmission system or rights and a buy-sell with a counterparty as "PacifiCorp Transmission Transactions." PacifiCorp used its transmission rights to move energy between the Malin and Captain Jack substations at COB. Malin is a terminus for two high-voltage transmission lines that are in the ISO's control area, and Captain Jack is a terminus for another line that is outside the ISO's control. PacifiCorp explained that it was using its transmission rights at COB to assist other entities in using their own transmission assets and rights. We cannot determine from the information in the company's FERC response whether another party could have used these "Transmission Transactions" to implement any of the Enron trading strategies.

In its Final Report in the Fact-Finding Investigation, FERC staff argued that PacifiCorp and others identified by the ISO as participants in the Enron trading strategies should be directed to show cause why they should not be found in violation of the ISO and PX tariffs and required to give back the related profits. FERC staff cited PacifiCorp's involvement in potential Ricochet deals, while the ISO has reported that the company collected congestion revenues from circulating trades (discussed above) and from counterflows that were later cancelled. FERC, however, has not yet issued the requested show cause orders.

Idaho Power

In its response to FERC's "admit or deny" request, Idaho Power denied participating in any of the Enron trading strategies. However, in the course of winding down the power marketing activities of its IDACORP Energy subsidiary in mid-2002, the company discovered and disclosed possible violations of FERC requirements, including 1) preferential transmission access for IDACORP Energy trades, 2) unapproved electricity transactions between IDACORP Energy and the utility, and 3) the unauthorized assignment of the utility's power marketing contracts to IDACORP Energy. These activities do not appear to be related to implementation of the Enron trading strategies, and Idaho Power is attempting to resolve the matter with FERC and the Idaho PUC.

On March 26, 2003, FERC investigative staff recommended that Idaho Power be directed to show why its bidding activity between May and October of 2000 and its participation in Enron trading strategies did not violate the ISO and PX tariffs and why it should not be required to return the associated profits. The staff's Final Report in the Fact-Finding Investigation notes that Idaho Power submitted bids to the ISO at the prevailing price cap ($750, $500, or $250 per MWh) on 23 days in mid-2000 and that the bids cannot be justified by the cost of generation. FERC staff calls this behavior economic withholding or inflated bidding. The staff's report also describes the company's involvement in potential Ricochet trades and points to the ISO's finding that it collected congestion revenues from circulating trades and from counterflows that were later cancelled. FERC, however, has not issued the requested show cause orders yet.

4. Potential Violations of Oregon Laws, Rules, and Orders

In this section, we discuss whether trading activities by PGE, PacifiCorp, and Idaho Power in 2000-01 violated any Oregon laws administered by the Commission or any of the Commission's own rules and orders.

We believe that three types of Oregon provisions are relevant here. The first two--merger conditions and affiliated interest requirements--are discussed below for PGE in the context of its dealings with EPMI. Trading by PacifiCorp and Idaho Power during the western energy crisis does not appear to raise the affiliate issues covered by these requirements. The third provision--the Commission's responsibility and authority under ORS 756.040 to protect customers--pertains to the trading activities of all three utilities in 2000-01.

ORS 756.040

ORS 756.040 sets out the Commission's general powers. It states that the Commission shall protect utility customers from "unjust and unreasonable exactions and practices" and "obtain for them adequate service at fair and reasonable rates."

Staff's counsel advises that the Commission has the authority under ORS 756.040 to reduce rates prospectively to compensate customers for the effects of past utility misconduct or mismanagement.[17] We address the misconduct and mismanagement cases in turn.

[17] The Commission can take this action without violating either the filed rate doctrine or limits on retroactive ratemaking. The filed rate doctrine is that as long as a rate is in effect consistent with Commission action, it is for all purposes the legal rate. Under the filed rate doctrine, a court cannot require refunds or reduce rates claimed to be excessive because of utility misconduct or mismanagement, but a commission can reduce rates going forward to compensate customers for the excess they paid in the past. This rate reduction would not be prohibited as retroactive ratemaking because it would be based on the effect of the misconduct or mismanagement, not on the extent to which past earnings were higher than expected.

Misconduct contributing to higher costs and rates

If a utility was involved in illegal trading activities and those activities contributed to higher wholesale prices in western markets and higher retail prices for the utility's customers, then a rate reduction based on some or all of the higher cost to retail customers could be justified.

A trading activity is illegal if it violates a law, tariff, or other legal requirement. In deciding whether a violation occurred, the Commission would not substitute its judgment for that of another agency with jurisdiction, e.g., FERC. The Commission could make its own determination of a violation only if the responsible agency did not or will not make a finding, as might be the case if the agency adopted a settlement among the parties.

The effect of the misconduct on wholesale prices and retail rates can be determined in two ways. First, the effect of the specific illegal trades could be traced. Second, some parties in the FERC proceedings have argued that if a utility was engaged in illegal trading activities, it could be considered, along with all others who participated in abusive practices that raised wholesale power prices, jointly and severally liable. The utility's involvement in the overall pattern of abuse would have to be significant for it to be considered jointly and severally liable. In that case the utility would be responsible, with those other parties, for all of the harm to its customers from the higher wholesale prices.

Any rate reduction to compensate for the harm from misconduct, however, could not be so large as to make it impossible for the utility to continue to provide safe and adequate service. Furthermore, the Commission would be able to order the utility to reduce rates for its retail customers, but it would not be able to order compensation for the customers of any other utility.

Mismanagement of trading activity

Utility customers are paying rates that include compensation for good management. If a company was negligent in managing a key area of its business--by failing to use due care in its trading activity--then a rate reduction to compensate customers because they did not get the management they paid for could be justified. A mismanagement case requires a showing that customers could have been harmed by the company's actions, not that they actually were harmed. Even if the company is required to hold customers harmless, e.g., by absorbing any penalty associated with its actions, the issue remains that customers paid more for management services than was reasonable. If mismanagement occurred, then a rate reduction could be linked to the harm to customers or to the amount of manager and officer compensation included in rates.

We now address whether the trading activities of each of the utilities violated these requirements.

PGE

We examined whether PGE violated conditions adopted by the Commission in its order approving the Enron merger, as well as requirements for filing transactions with affiliates. In addition, we considered whether a reduction in rates is justified in order to compensate customers for the company's misconduct or mismanagement.

Merger conditions

When the Commission approved the merger of Enron and Portland General Corporation (PGC) in 1997 (Order No. 97-196), it adopted a stipulation signed by the applicants and other parties to the proceeding. The stipulation set forth a number of conditions, two of which relate to the trading activities at issue here.

Condition 10 of the stipulation states:

> Enron guarantees that the customers of PGE shall be held harmless if the merger between Enron and PGC results in a higher revenue requirement for PGE than if the merger had not occurred.

Under Condition 21 of the stipulation, the Commission can impose the penalty set out in ORS 756.990 if Enron violates the hold harmless condition. Condition 21 also provides that: 1) the Commission can impose the penalty directly, without first obtaining an order of the Circuit Court, and 2) the monies are to be placed in a deferred account (for customers), instead of being sent to the General Fund. Staff's counsel advises, however, that the Commission would have to go to Circuit Court and the penalty would go to the General Fund, because these Condition 21 provisions conflict with the language and interpretation of ORS 756.990 and cannot trump the statute. ORS 756.990(2) allows a penalty of up to $10,000 for each time that a person fails to comply with a Commission order. The Commission may be able to impose a higher penalty if needed to match the harm to customers by treating violation of Condition 10 as a continuing violation and imposing the $10,000 penalty each day. Condition 10, however, is written as a guarantee by Enron. It may not be possible to collect a penalty from Enron for violating the condition because the company is bankrupt.

Concluding that Enron, through the trading with PGE described in Section 3, violated Condition 10 requires all of the following four findings: 1) the trading would not have occurred absent the merger, 2) the trading caused wholesale market prices to be higher by some amount, 3) PGE's retail rates are higher because of the effect on wholesale prices, and 4) the harm from this trading activity exceeds the net of any other costs and benefits of the merger.

Determining the effect of the trading activity on wholesale market prices--the second finding needed for a violation of Condition 10--is problematic. It should be possible to trace any effect of the Enron-PGE Death Star deals on the market, but that effect is likely to be very small, for three reasons: the deals involved less than 2500 MWh, Enron did not collect much--less than half a million dollars--for congestion relief from this type of Death Star transaction in the entire 1998-2001 period, and the congestion relief payments were apparently not included in published index prices. Furthermore, as explained by PGE in the testimony it submitted in its FERC case (EL02-114-000), Death Star may have actually relieved congestion and reduced costs in California. An alternative theory about the effect of the Enron trading strategies and other abusive practices on the market is that there was a "snowball" effect, i.e., those practices created uncertainty about the workings of the market, which caused buyers to panic and bid prices up even higher.[18] This snowball effect, however, is difficult to prove, and it is implausible that the small volume of Enron-PGE Death Star trades had any significant effect on it. PGE's posting errors may have allowed EPMI to obtain service that was not available to others, but, as noted in Section 3, the errors apparently had no adverse effect on the market.

The fourth element of a Condition 10 violation--that the harm from the trading activity causes PGE's revenue requirement to be higher than if the merger had not occurred--would require an assessment of other costs and benefits of the merger. This "but for" test would be difficult to conduct at this point, almost six years after the merger was approved.

Since we believe it is unlikely that the Commission will be able to make two of the necessary findings, we do not recommend pursuing a violation of Condition 10.

Condition 15 of the Enron merger stipulation states, in part:

> PGE shall not give its affiliates preferential access through any prearranged, formal or informal, agreement with any of its affiliates regarding PGE's power or natural gas assets.[19]

[18] In its Initial Report in FERC's Fact-Finding Investigation, the agency's investigative staff concluded that the Enron trading strategies "adversely affected the confidence of markets far beyond their dollar impact on spot prices."

[19] We believe "power" here includes transmission as well as generation, so that the condition applies to PGE's use of its transmission facilities and rights in trading with EPMI. Because of FERC's open access

The penalty provisions described above for Condition 10 also apply to Condition 15.

A decision by FERC in its PGE investigation (EL02-114-000) that the company violated the code of conduct and tariff provisions governing dealings with affiliates would be clear evidence that PGE violated Condition 15. If FERC makes no findings on whether PGE gave preference to EPMI (if the case is settled, for example), the Commission could open its own investigation into possible violation of Condition 15. The case that PGE did violate the condition would most likely focus on transactions that were not posted properly and on Death Star deals. PGE's admitted failure to post transactions correctly does not prove that PGE gave EPMI preferential access to its transmission. It only demonstrates that PGE could have given such preference. We would need to examine the transactions that were posted improperly for some advantage for EPMI and address PGE's argument that EPMI did not benefit because it could have obtained the same service from others at lower cost. The Death Star transactions may be evidence that PGE gave preference to EPMI because, as discussed below, the deals should have raised red flags about their purpose because they were more complicated than they needed to be. PGE may have turned a blind eye to a deal with EPMI that it would have questioned and maybe rejected if offered by anyone else.

<u>Affiliated interest requirements</u>

ORS 757.495 requires PGE to file with the Commission any contract to buy power from Enron within 90 days of execution in order for the company to include the purchase costs in retail rates. OAR 860-027-0040(3)(b)(A) allows an exemption from this filing requirement for transactions carried out under the terms of a FERC tariff. PGE operated under this exemption in 2000-01.

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requirements, the power or generation side of the business is often distinguished from the transmission side, but that distinction was not common when the merger stipulation was signed in 1997.

It could be argued that if PGE was not complying with FERC requirements (e.g., it violated the code of conduct), then it was not entitled to the filing exemption and was operating without the necessary approvals. In that case, PGE would not be able to recognize the costs of purchases from Enron in rates.

This argument has two serious shortcomings. First, almost all of PGE's purchases from EPMI were priced at a market index (usually mid-Columbia). If PGE had filed a contract to buy power on those terms for review under ORS 757.495, the Commission would probably have approved the contract as "fair and reasonable and not contrary to the public interest" because the purchases were at published market prices. It would not have detected that the purchases were part of a deceptive trading strategy or that EPMI was afforded any preference. Second, none of the Enron purchases are recognized in PGE's current base rates. Customers are still paying excess net power costs deferred in the first nine months of 2001, but removing any purchases from Enron at index rates from the deferral mechanism (and replacing them with other market purchases) would have no effect on the calculated rate adjustment.

ORS 756.040

As discussed above, the Commission can reduce rates prospectively to compensate customers for the effects of past misconduct or mismanagement by PGE.

The two key elements of a misconduct case are 1) whether PGE was engaged in illegal trading activities, and 2) whether the activities contributed to higher costs and retail rates for the company. With respect to the first element, FERC at this point has not ruled that PGE broke any federal laws or requirements. FERC's trial staff has argued in EL02-114-000 that the company violated the Federal Power Act and provisions of its market-based rate authority, but the case is ongoing. FERC investigative staff alleges that PGE engaged in other trading practices that violate the ISO and PX tariffs, but FERC has not yet issued the show cause orders requested by the staff. On the second element of a misconduct case, the effect of the Death Star deals and posting errors on wholesale market prices apparently was small (and in the case of Death Star may have been a benefit, not a harm), as discussed above. The effect on market prices does not come close to the threshold for PGE to be considered jointly and severally liable for the harm to its customers from abusive market practices.

We believe, however, there is a prima facie case that PGE mismanaged its trading activities with Enron, based on the following:

- PGE failed to properly post 65 percent of its transactions with EPMI in 1999-2001. This apparent violation of its FERC tariff jeopardized PGE's ability to sell excess power at market prices. Without its market-based rate authority, the company would be limited to charging a rate based on its costs, which could be less than prevailing market prices. Since wholesale sales margins are credited to customers, either on an expected basis in estimating base power costs or on an actual basis in a power cost adjustment, PGE's retail customers could have been harmed by the loss of market-based rate authority. The company failed to have management controls in place to ensure it was posting its trades with EPMI in accordance with the requirements of its FERC tariff or to catch any errors after the fact. (PGE discovered the errors when it started to review its transactions with affiliates after FERC opened its Fact-Finding Investigation in early 2002.)

- PGE should have questioned the "17 day" transactions.

    - PGE is subject to regulatory requirements (in the merger conditions adopted by the Commission in Order 97-196 and in the company's FERC tariffs, for example) that prohibit it from giving undue preference to its Enron affiliates. These requirements should have made PGE more vigilant and cautious in its dealings with Enron.

    - PGE rejected Enron's request for it to assist in another trading strategy less than a year before the 17 day transactions began. In 1999, EPMI devised a plan that started with it prescheduling (i.e., scheduling in the day-ahead market) transmission for a large block of power to flow north in California for delivery at COB or elsewhere in the Northwest. EPMI would then cancel the deal at the last minute, forcing the ISO to buy power from EPMI and other suppliers to rebalance the system. In order to reserve the transmission capacity in the day-ahead market, EPMI needed to identify a sink for the power in the Northwest and approached PGE to play that role. PGE declined to participate, and it obtained legal advice that it would have run the risk of paying more for ancillary services, violating consumer protection laws in California, and losing its market-based rate authority. However, there is no evidence that anyone at PGE scrutinized the 17 day transactions anywhere near as much as the 1999 proposal by EPMI.

- PGE's managers and traders knew or were told that the 17 day transactions were being done to get around the ISO's prohibition on scheduling reversals at COB and that no power was actually flowing.
- The convoluted nature of the deal should have raised red flags about its purpose. Avista appears as a "sleeve" between EPMI and PGE twice, first at COB (Steps 2 and 3 in Table 1) and then again at PGE System (Steps 5 and 6). A "sleeve" is an intermediary who steps between two parties, usually because they cannot deal directly for credit or affiliate reasons. Without Avista, Steps 2-9 reduce to PGE buying from EPMI at COB and selling back to EPMI at John Day. The reason for using Avista as a sleeve may have been to move PGE's posted buy from EPMI from COB to PGE System. Since PGE System is a much less active trading point than COB, the shift in posting made the deal less visible and less attractive to traders.

These points indicate that PGE was negligent in managing its trading with Enron.[20] The case for mismanagement, however, is not open-and-shut. PGE has argued that:

[20] We also believe PGE's use of its AC Intertie and IR contracts should be examined further. The AC Intertie agreement provides PGE with both northbound and southbound transmission rights. The company has reserved the northbound rights, from COB to PGE's system, for its native load customers

- The error rate for its postings was 3 percent, not 65 percent. Most of the alleged errors involved a difference between the posted offer and acceptance, but in those cases the deal with Enron was still visible and available to others.

- The 1999 episode shows that PGE was careful in its dealings with Enron. In addition, the deal proposed by EPMI in 1999 was deceptive (in that EPMI never intended to complete the scheduled transaction), but the 17 day transactions appeared legitimate.

- PGE's traders were confused about the 17 day transactions, the transcripts of their conversations do not contain any clear statements that they thought the deals were illegal or improper, and their much-publicized use of terms like “bogus” and “scam” was just an expression of their frustration at having to complete a complicated transaction on a tight deadline.

- It was well known (but undocumented) that the ISO required energy delivered at COB to sink in the Northwest before being imported back into California, and PGE had provided a similar service to an unaffiliated party on at least one occasion (to Modesto Irrigation District in early 1999) before the 17 day transactions began.

- PGE’s traders and managers were unaware that EPMI was running Death Star because they could not see the Mead to COB portion of the loop. The portion of the deal they saw appeared to be legitimate and earned the company a reasonable margin.

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and therefore has not offered to sell these rights under its FERC open access tariff. By using these rights in the Death Star transactions (Step 4 in Table 1), PGE may have given EPMI preferential access to its transmission assets. In effect, PGE provided wheeling services to EPMI that it failed to make available to others.

The IR agreement gives PGE firm transmission rights from its generating plants to its system and to the John Day substation. The agreement allows dynamic scheduling and provides PGE with non-firm flexibility. However, it prohibits third party wheeling, and PGE’s use of the transmission rights on behalf of EPMI might have violated the terms of the agreement and jeopardized its continued use. According to the Bonneville Power Administration (BPA), PGE could not have violated its IR agreement because it did not use those rights to move power from its system to John Day (Step 8 in Table 1). BPA claims that it provided the transmission on an hourly non-firm point-to-point basis. PGE, however, has repeatedly stated that it used its IR contract rights, so the issue is unresolved.

- The main purpose of real-time trading was to balance PGE's loads and resources. Real-time trading was not as big a money-maker for the company as other trading activities, and the volume of Death Star trades (15 days, 2,500 MWh) was not otherwise large enough to catch management's attention.
- The Avista sleeve that complicates the transaction existed only because PGE could not figure out how to post the buy-sell with EPMI otherwise.
- Even if the 17 day transactions were part of a Death Star strategy, customers were not harmed and may in fact have benefited.

PGE argues that it did not knowingly participate in Death Star, and there is, in fact, no direct evidence at this point that it knew the purpose of the transactions. The mismanagement case, however, does not rest on PGE knowing that the 17 day transactions were illegal. Instead, it is based on the argument that the company should have looked more carefully at the deal EPMI brought to it. Furthermore, while PGE may now argue that its posting requirement is vague and that it met the intent of the requirement in almost all cases, we are not aware that it has any response to the argument that the company mismanaged the task of ensuring that it posted its trades in accordance with the terms of its FERC tariff.

PacifiCorp

Nothing in PacifiCorp's response in FERC's Fact-Finding Investigation suggests that the company violated any FERC or OPUC requirements for dealings with affiliates. The company admitted to Export of California Power, but we are not aware of any tariff it violated[21] and its Oregon customers probably benefited from the transactions.[22] FERC

[21] FERC staff's Final Report in the Fact-Finding Investigation does not cite Export of California Power as a potential violation of the ISO and PX tariffs.

investigative staff believes that other PacifiCorp trades may have violated the ISO and PX tariffs, but FERC has not directed the company to respond. A FERC finding that the company violated the ISO or PX tariffs would be evidence of misconduct. However, we do not have enough information at this time to determine whether the company engaged in misconduct or mismanaged its trading activities.

Idaho Power

Idaho Power has denied involvement in any of the Enron trading strategies, and the affiliate issues under review at FERC and the Idaho PUC appear unrelated. FERC investigative staff argues that some of Idaho Power's bidding and trading activities violated the ISO and PX tariffs, but FERC has not directed the company to respond. A FERC finding that Idaho Power violated the ISO or PX tariffs would be evidence of misconduct. However, we do not have enough information at this time to determine whether the company engaged in misconduct or mismanaged its trading activities.

[22] Oregon customers were exposed to excess power costs through a deferral mechanism beginning November 1, 2000.

5. Recommendations for Commission Action

We present one overall recommendation and then one recommendation for each of the three utilities.

Overall

Recommendation
Affirm that the Commission will hold customers harmless for any penalties imposed by FERC or any other authority.

PGE

Based on the available evidence, we believe that a formal investigation of PGE's trading activity in 2000-01 is warranted and that parties should be allowed to argue before the Commission whether PGE is guilty of misconduct and/or mismanagement. The key question in deciding how to proceed is whether to wait for FERC to complete its investigations into possible tariff violations by PGE. We present three options for Commission action.

Option 1: Open a two-stage proceeding now on PGE's trading activity in 2000-01. The first stage would address whether PGE is guilty of misconduct and/or mismanagement. The second stage, if needed, would determine what relief is appropriate.

Under Option 1, parties would be allowed early in the first stage of the proceeding to argue for expanding the scope of the investigation beyond the 17 day transactions and the posting violations. A party could make its case in two ways. The first is to introduce evidence of other possible misconduct by PGE that is produced if FERC issues the show cause orders requested by its staff. Second, a party could identify trading practices it considers illegal and propose ways to screen or sort PGE's trading data to determine whether the company engaged in those practices (like PGE did to search for Death Star transactions). PGE would be able to respond to the parties' proposals. If FERC declines to issue the show cause orders or otherwise limits the scope of its further investigation of the Enron trading strategies, PGE might argue that FERC has concluded that certain trading activities are legal and therefore that they should not be addressed in the OPUC's proceeding. The company could also argue that the proposed screens are impractical or not likely to reveal new information. The Commission would then decide whether to consider evidence from any new FERC show cause proceeding or require PGE to conduct any of the screens. We believe this scoping step can be completed within 90 days after the start of the investigation. Parties would then be able to develop evidence (through data requests, for example) on the trading activities included in the scope of the proceeding.

We believe the opportunity to argue for expanding the scope of the investigation beyond the 17 days and the posting violations should be limited in this way because substantial work has already been done by FERC staff and others to identify PGE involvement in illegal trades. FERC trial staff in EL02-114-000 listened to tapes and followed up with data requests on 20 other days of trades and found no evidence that PGE participated in other Death Star deals or in any of the other Enron trading strategies. Similarly, the depositions of PGE traders we participated in revealed no further PGE involvement in the Enron strategies. FERC investigative staff has issued its Final Report on the Enron trading strategies, and FERC itself will decide soon whether to issue show cause orders. As a result, we do not believe that open-ended discovery, e.g., demanding and then reviewing tapes or transcripts of all PGE trader conversations in 2000-01, would be productive. With the exception noted below, the scope of the investigation should not be expanded unless FERC pursues other potential tariff violations or a more focused search for trading practices the Commission considers illegal uncovers further PGE involvement.

The exception is that if Tim Belden (or any other Enron trader) provides evidence that PGE participated in other allegedly illegal trading practices, then the Commission would again consider expanding the scope of the investigation. As noted above, Belden is very knowledgeable about EPMI's trading with PGE but has not been available for questioning. We will continue our efforts to question him. Since we cannot be sure when parties will have access to Belden, we recommend that the ability to ask to expand the scope of the investigation based on his comments not be limited to the 90-day period outlined above.

The first stage of the proceeding should have a firm end date, that would be allowed to slip only if solid evidence of additional PGE participation in illegal trading strategies surfaces (through disclosures by Belden, for example) and requires further investigation. We suggest an end date 90 days after FERC issues its decision in its PGE investigation (EL02-114-000). The presiding judge in the case intends to issue an initial decision in mid-July. We expect a FERC ruling shortly thereafter, since FERC has indicated that it wants to wrap up its western market investigations as soon as possible.

If the Commission concludes in the first stage of the proceeding that PGE engaged in misconduct and/or mismanaged its trading activities, then a second stage to consider relief would begin. If PGE is guilty of misconduct, we recommend that the Commission decide early in the second stage the nature of the relief it believes is appropriate, since some of the options would require further discovery and analysis to apply. There appear to be two options for dealing with misconduct. First, the Commission could choose to compensate customers for the harm caused by the specific transactions that constitute the misconduct. Second, if the misconduct is based on a FERC finding that PGE gave EPMI undue preference, the Commission could find that PGE violated Condition 15 (no preferential access for affiliates) of the Enron merger stipulation and go to court for the associated fines. The first of these options would require further work to determine the effect of specific transactions on PGE customers.

If PGE is guilty of mismanagement, some discovery on management compensation included in rates might be necessary. Once the Commission has any information it needs on the effects of mismanagement or on management compensation, it would pursue the appropriate rate reduction for customers through a general rate case under ORS 756.515.

<u>Option 2</u>: Open a two-stage proceeding now to address whether PGE mismanaged its trading activities in 2000-01. Delay any decision on a misconduct case until FERC completes its investigations.

Option 1 presumes that FERC will decide the current PGE case (EL02-114-000) shortly after the initial decision scheduled for mid-July and expedite any proceedings resulting from its staff's request for show cause orders. But that timing is not certain, and it may be inefficient to open a misconduct case now and expand and contract its scope as FERC makes decisions in its various cases. Any misconduct case will most likely be based on a FERC decision that PGE violated tariff requirements. Option 2, therefore, addresses mismanagement now but delays any misconduct case until FERC finishes its work. The first stage of the mismanagement case would develop evidence that PGE failed to post its trades with EPMI properly and that it should have questioned the 17 day transactions more closely. Since PGE could be guilty of mismanagement even if it did not violate its tariffs, the case can proceed before FERC completes its investigations.

With the record developed in EL02-114-000, we believe that the investigation into possible mismanagement can be conducted expeditiously. If the Commission finds that PGE mismanaged its trading activities, the second stage of the proceeding would address relief, e.g., a rate reduction to compensate customers because they paid for good management but did not get it. The Commission could pursue a rate reduction through a rate case initiated under ORS 756.515.

Option 3: Delay any decision on opening a formal investigation of possible misconduct or mismanagement by PGE until FERC completes its proceedings.

As explained above for Option 2, it may make sense to delay any misconduct case until FERC wraps up its investigations. The FERC proceedings may also provide evidence of possible mismanagement beyond the instances of the 17 day transactions and the posting errors. Further evidence of misconduct may itself be considered evidence of mismanagement. Option 3, therefore, delays any Commission action on possible misconduct or mismanagement by PGE.

Recommendation

We recommend the Commission pursue Option 2, by opening an investigation into possible mismanagement by PGE related to the 17 day transactions and the posting errors. We believe there is enough information available on these events to proceed now. If the FERC investigations, when completed, point to other areas of possible mismanagement, the Commission can open further proceedings at the time.

PacifiCorp

Recommendation

Direct staff to examine further PacifiCorp's trading activities in 2000-01 and report back in 90 days whether the Commission should open a formal investigation into misconduct or mismanagement.

Discussion

We limited our review for this report to information available from PacifiCorp's response to FERC's May 8, 2002 request. As noted above, we cannot determine from this information whether the company engaged in misconduct or mismanaged its trading activities. We propose to obtain further information from PacifiCorp (e.g., through informal data requests and meetings), mainly with respect to the "Transmission

Transactions." We also expect that if FERC decides to issue the show cause orders requested by its staff, PacifiCorp's response will be available soon enough for us to report back to the Commission in 90 days with a recommendation on how to proceed.

Idaho Power

Recommendation

Direct staff to examine further Idaho Power's trading activities in 2000-01 and report back in 90 days whether the Commission should open a formal investigation into misconduct or mismanagement.

Discussion

Idaho Power informs us that it is close to resolving its affiliate issues with FERC. In addition, we expect that if FERC is going to issue a show cause order (on the company's possible involvement in some of the Enron trading strategies and in economic withholding), it will act quickly and that Idaho Power's response will be available soon after.