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Benchmarking the Price Reasonableness of a Long-Term Electricity Contract

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The authors wish to express their thanks to Earle H. O'Donnell, chair of the Energy and Communications Practice Group at Dewey Ballantine LLP, and Joshua Bar-Lev, manager of the law department at Pacific Gas and Electric Company, for their comments.

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Abstract

With the retreat of the merchant power sector due to financial and market constraints, more utilities are turning to affiliates to contract long-term generation to meet forecast load growth. That has led to a growing number of cases before the Federal Energy Regulatory Commission (FERC) in which independent generators question whether the utility has given improper preferential treatment to its affiliate in the bidding process. An analysis of FERC's market-based price benchmarking approach in Pacific Gas & Electric's 2001 application seeking FERC approval of a long-term contract with its affiliate generator leads to the conclusion that given suitable comparable contract data, FERC's approach is useful for gauging the price reasonableness of a long-term affiliate contract. However, if comparable market data is unavailable, this paper recommends that FERC augment its market price approach with a long-run marginal cost analysis, which is already the standard for most cost-recovery decisions at the state-level. The long-run marginal cost methodology described in this paper is directly applicable to the screening and acquisition of new generation resources.

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I. INTRODUCTION AND SUMMARY

A. Background

Electric utilities in the US have been engaging in wholesale electricity trading since well before the 1978 passage of the Public Utility Regulatory Policies Act (PURPA) that encouraged the development of qualifying cogeneration and small power production facilities and engendered the emergence of independent power producers (IPPs). The pre-PURPA trading was dominated by bilateral transactions largely comprising:¹

- (a) seasonal exchanges, where a winter-peaking utility supplies energy to a summer-peaking utility that returns the energy in the winter at a preset exchange ratio;
- (b) sales of economy energy by a utility with surplus generation and relatively low fuel cost to a utility with relatively high fuel cost, with the transacting utilities sharing the resultant fuel cost savings;
- (c) reserve sharing, whereby two or more utilities, likely with differing demand patterns and plant mixes, pool their reserves for reliability planning purposes, and
- (d) emergency support, where two or more utilities agree to supply each other when one experiences a real-time operation shortage.

These transactions were often the result of power pooling agreements among utilities.²

For example, the California Power Pool (CPP) was formed in 1961, with participation by Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E). The CPP agreement aimed to

¹ ENERGY INFORMATION ADMINISTRATION, ELECTRIC POWER ANNUAL 2000 VOLUME II 59, 60.

² PACIFIC GAS AND ELECTRIC COMPANY, AN ENCYCLOPEDIA OF UTILITY INDUSTRY TERMS 258-262 (1985).

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provide for the sale, pooling and sharing of energy sources both for reserve margins and emergency situations.

Fuel cost saving was the key driver for transactions under (a) and (b) above. Reliability and operational benefits rationalize transactions under (c) and (d). As these transactions delivered obvious benefits to both parties, regulatory approval at the federal and state levels was routine, without the fanfare of a contentious evidentiary hearing.

B. Price Benchmarking Based on Avoided Costs

The 1978 PURPA required a utility to purchase power output from a qualifying facility (QF). Section 210 of the PURPA requires that the rates paid to QFs be “just and reasonable” and “shall not discriminate against qualifying cogenerators.” However, the rates should not “exceed the incremental cost to the electric utility of the alternative electric energy” (i.e., the costs the utility avoided by purchasing from the QF).³ In general, PURPA delegated the responsibility for determining the utility’s avoided cost and enforcement of the utility’s purchase obligation to the states.

Armed with this PURPA authority, a state regulator decides the rate to be paid to a QF by a regulated utility that does not exceed the per-unit cost that the utility can avoid as a result of the QF purchase.⁴ For example, the California Public Utilities Commission (CPUC) in July 1985 issued Decision 85-07-022 stating that the total avoided cost is the difference between (a) the utility’s total cost without the QF purchase, and (b) the utility’s total cost with the QF purchase.⁵ Hence, implementation of PURPA necessitates

³ The Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, sec. 210.

⁴ RICHARD F. HIRSH, *POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM* 89 (The MIT Press 1999).

⁵ Dec. 85-07-022, *Long-Run Avoided Cost Methodology*, California Pub. Util. Comm’n (1985).

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the use of a price benchmark: the buying utility's per kWh of avoided cost due to a QF purchase. If the QF price is set at or below a utility's *ex post* per kWh avoided cost, which can vary continuously with actual operations, the utility's customers are *a priori* not disadvantaged by the QF purchases.⁶

However, a QF contract may have a fixed price term that lasts for up to 10 years in California, and longer elsewhere. When a long-term QF contract's price is capped at a utility's unbiased projection of avoided cost, the QF purchase should *ex ante* not increase the utility's expected rates. To be sure, as FERC observed in the preamble to its rules implementing PURPA,⁷ the QF price may turn out to be higher or lower than the utility's actual avoided cost. Nonetheless, an unbiased avoided cost projection is the commonly used benchmark by state regulators for capping the price of a long-term QF contract.⁸ Thus, QF pricing illustrates the important and relevant role of price benchmarking in ensuring that a utility's rates are "just and reasonable", as required by Section 210 of PURPA.

State regulators have extended cost-based price benchmarking beyond QF pricing, reflecting their oversight responsibility for cost prudence. A transaction is said to be prudent if its price is below the adopted benchmark, which is often a utility's per kWh

⁶ See C.K. Woo, *Inefficiency of Avoided Cost Pricing of Cogenerated Power*, 9:1 ENERGY JOURNAL 103-113 (1988).

⁷ 45 Fed. Reg. 12224 (Feb. 25, 1980).

⁸ Hirsh, *supra* note 4, at 97: "The interim [Standard Offer 4] SO4 contract called for payments to QFs based on the forecasted prices of fuel and capacity for the first ten years of a fifteen- to thirty-year contract period. According to conference participant Janice "Jan" Jamrin, director of the Independent Energy Producers Association, most people 'thought that gas and oil prices were going to the moon,' even though some fuel prices had already moderated slightly by the beginning of 1983. (While California wellhead crude oil prices had fallen from almost \$42 per barrel in 1981 to \$32 in 1983, the price of the state's natural gas, a premium fuel used in several cogeneration projects, was still heading up.) Rates paid to QFs for the first decade therefore reflected the view that fuel costs (and avoided costs) would escalate for the ten-year period. Under the terms of an SO4 contract offered by Southern California Edison, for example, energy payments rose from 5.6 cents per kWh in 1984 to 10.1 cents per kWh in 1993; capacity payments added another 1.42 to 2.07 cents per kWh."

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avoided cost. The types of transactions are diverse, ranging from utility-sponsored programs for conservation and demand-side-management (DSM) to the utility's long-term power procurement from wholesale markets.⁹ Indeed, in October 2002 the CPUC affirmed that “[t]o justify as cost-effective an IUE [inter-utility exchange] to reduce RNS [residual net short] (acting as a buyer), the utility will have to demonstrate that at the time of executing the IUE agreement the expected cost for repayment was less than the avoided incremental costs at the time of delivery.”¹⁰

By contrast, the Federal Energy Regulatory Commission (FERC) applies market-based price benchmarking to determine the price competitiveness of a utility's purchase from its affiliate generator. In a series of decisions to be discussed below, FERC held that a long-term contract between a utility and its affiliated generator that did not result from competitive solicitation (e.g., auction) can still be just and reasonable if it passes a price-benchmarking test. The test aims to foreclose self-dealing behavior by the affiliated buyer, whereby the utility might try to offer its affiliated generator an above-market price that leads to higher rates for the utility's customers.

C. Research Agenda

This paper analyzes the approaches to price benchmarking used by the FERC and a state regulator, exemplified by the CPUC. Our choice of the California example is motivated by the 2002 passage of state Assembly Bill (AB) 57, which reforms the

⁹ See Ren Orans, C.K. Woo and Brian Horii, *Targeting Demand Side Management for Electricity Transmission and Distribution Benefits*, 15 *MANAGERIAL AND DECISION ECONOMICS* 169-175 (1994). See also Ren Orans, C.K. Woo, Roger Pupp and Ira Horowitz, *Demand Side Management and Electric Power Exchange*, 16 *RESOURCE AND ENERGY ECONOMICS* 243-254 (1994).

¹⁰ Dec. 02-10-062, *Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Dev.*, California Pub. Util. Comm'n 33 (2002).

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recovery of electricity procurement costs incurred by PG&E, SCE and SDG&E.¹¹

Implementation of AB 57 by the CPUC diminishes the need for after-the-fact reviews of transactions whose price terms pass their respective benchmarks for price reasonableness.¹²

Our inquiry is substantive and relevant because, as discussed below, affiliate transactions appear to be on the rise. Absent long-term financing, investment in new generation evaporates. Nonetheless, a regulated utility must fulfill its obligation to serve. To meet growing load, it may pursue a long-term contract with its affiliate seller who can lean on the buying utility's predictable cash flow from retail sales to obtain long-term financing.

In May of 2003, FERC questioned eight long-term contracts signed by Entergy Services, saying that the New Orleans-based utility may have given improper preferential bidding treatment to its affiliates. Protesters in the case, including Dominion Virginia Power, Tractabel Energy Marketing, TECO Power Services Corporation, Electric Power Supply Association and Calpine Corporation, alleged that Entergy Services: (1) has not shown that the winning affiliate bids are the best alternative identified through the RFP process; (2) has not demonstrated that the RFP criteria are unbiased and that the selection process was fair and non-discriminatory; and (3) has not shown that it has taken steps to mitigate its generation market power.¹³ FERC stated that the power supply agreements "have not been shown to be just and reasonable, and may be unjust, unreasonable and

¹¹ Assemb. B. 57 § 454.5 of the Public Utilities Code (Cal. 2002).

¹² Dec. 02-10-062, California Pub. Util. Comm'n 53 (2002).

¹³ *Order Accepting and Suspending Power Purchase Agreements, Subject to Refund, Establishing Hearing Procedures, Denying Privileged Treatment, and Consolidating Dockets*, 103 F.E.R.C. ¶ 61,256 (May 30, 2003).

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unduly discriminatory or preferential, or otherwise unlawful.”¹⁴ Calpine told Reuters: “This has been a real issue that merchant companies have been facing around the country—apparent preferential treatment with utility affiliates.”¹⁵ Entergy has argued that the RFP process was fair, competitive and monitored by an independent consultant. Other recent examples of affiliate transactions that have come under FERC scrutiny include Southern Power, Ameren Energy Marketing and Cinergy Energy Services.¹⁶

Our inquiry is also motivated by the different emphases of the FERC and CPUC approaches. FERC’s focus is on self-dealing. If a long-term contract with an affiliate meets FERC’s standards for competitive procurement, the contract can be accepted as reasonable, irrespective of the contract’s price or other term, thus precluding the need for price benchmarking. Otherwise, the affiliate transaction’s price term will be subject to a benchmark based on contracts that are “comparable” to and “contemporaneous” with the affiliate contract. To prove that the affiliate transaction has terms as favorable as those of an arms-length transaction, the sample of contracts for price benchmarking should exclude contracts between the utility and its affiliate. As well, the utility and its affiliate must show that they do not have market power that can potentially influence market prices in general and the price terms in the sample contracts in particular. FERC does not require the affiliate contract’s price be at or below the utility’s state-set avoided cost (if any). In short, FERC’s price benchmarking is a market-price test. In *Ocean State II*, FERC clearly distinguished the market-based approach from the cost-based one: “[i]n the case of a market-based formula rate...neither the rate (which is the formula itself) nor

¹⁴ *Id.*, at 25.

¹⁵ *FERC Questions Entergy Affiliate Power Contracts*, REUTERS, June 2, 2003.

¹⁶ *Southern Power Company*, 104 F.E.R.C. ¶ 61,041 (2003). *See also Ameren Energy Marketing*, 99 F.E.R.C. ¶ 61,226 (2002). *See also Cinergy Energy Services, Inc.*, 102 F.E.R.C. ¶ 61, 128 (2003).

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any of its individual components has to be justified on a cost basis. Rather, if the Commission is satisfied that the rate results from competitive market forces or that the seller does not have market power over the buyer we do not examine the underlying cost structure of the seller.”¹⁷

The CPUC’s focus is cost prudence. In compliance with AB 57, each utility must file a procurement plan for approval by the CPUC that enables the utility to fulfill its obligation to serve at “just and reasonable” rates and minimizes the need for after-the-fact reasonableness reviews. Specifically, AB 57 requires each utility’s plan to have the following elements:¹⁸

- (1) An assessment of the price risk associated with the electric corporation’s portfolio.
- (2) A definition of each product, including support and justification for the product type and amount to be procured under the plan.
- (3) The duration of the plan.
- (4) The duration, timing, and range of quantities of each product to be procured.
- (5) Details of a competitive procurement process.
- (6) Details of the incentive mechanism, if one is proposed.
- (7) The upfront standards and criteria by which the acceptability and eligibility for rate recovery of a proposed procurement transaction will be known by the electrical corporation prior to execution of the transaction.
- (8) Procedures for updating the procurement plan.

¹⁷ *Ocean State Power II*, 69 F.E.R.C. ¶61,546 (1994).

¹⁸ Assemb. B. 57 § 2, § 454.5 (2002).

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(9) A plan that includes procurement of renewable resources, with the goal of ensuring that an additional 1 percent per year of the electricity sold by the electrical corporation is generated from renewable energy resources, until 20 percent of the portfolio is renewable.

(10) The creation or maintenance of a diversified electricity portfolio with both short-term and long-term products.

(11) The electrical corporation's risk management policy, strategy and practices.

(12) A plan to achieve appropriate increases in diversity of ownership and diversity of fuel supply of non-utility electrical generation.

(13) A mechanism for recovering reasonable administrative costs related to procurement in the generation component of rates.

The FERC and CPUC approaches to benchmarking employ very different data. The FERC approach uses market data on comparable and contemporaneous contracts. But ideal data are seldom readily available. As a long-term electricity contract can have idiosyncratic terms, there can be substantial debate over whether the comparison contracts are sufficiently comparable to the affiliate contract. Depending on the liquidity of the market, it may be difficult to find contracts that are both comparable to and contemporaneous with the affiliate contract. Moreover, the price terms in these comparison contracts should be competitive and not influenced by the seller's market power.¹⁹ The lack of ideal data necessitates the use of a sample of contracts determined to (a) have terms sufficiently similar to those of the affiliate contract, (b) be reasonably close (in time) to the affiliate contract's signing, and (c) have price terms not unduly

¹⁹ *Ocean State Power II*, 59 F.E.R.C. ¶ 62,337 (1992).

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influenced by market imperfections. This determination entails some degree of subjectivity and the choice of sample contracts can obviously affect the resulting price benchmark.

The CPUC's approach to price benchmarking does not require contract data. Rather, it uses publicly available cost data on generation capacity, financing, variable O&M, emissions, and fuel to calculate the long-run marginal cost (LRMC) of generation, the all-in per kWh cost of owning and operating new generation. In the case of California, the CEC publishes such cost data in its long-run market price projection. Such cost data and their implications are well-understood by the regulator and the regulated utilities because of their experience with avoided cost pricing and cost-effectiveness analyses in integrated resource planning. The resulting benchmark, being cost-based, is less vulnerable to the potential price distortions caused by electricity market imperfections.²⁰ The CPUC has used this approach to determine the cap for the formerly integrated utilities' long-run avoided cost for QF pricing under Section 210 of PURPA and to perform cost-effectiveness evaluations of resources.²¹ The California Energy Commission (CEC) has also used it to project the long-run price in California for guiding the state's resource planning.²²

Finally, the FERC and CPUC approaches can have very different results, even though economic theory suggests that in a competitive market with easy entry and exit,

²⁰ To be sure, a dominant firm can manipulate a fuel price such as natural gas. FERC found that El Paso Natural Gas was guilty of a "clear exercise of market power" when it withheld from Western markets as much as 696,000 Mcf/day during 2000-2001 winter heating season. *See FERC ALJ Rules El Paso Natural Gas Withheld Gas in West*, MEGAWATT DAILY, Sept. 24, 2002, at 1.

²¹ CALIFORNIA PUBLIC UTILITIES COMMISSION & CALIFORNIA ENERGY COMMISSION, STANDARD PRACTICE MANUAL (1987).

²² CALIFORNIA ENERGY COMMISSION, DOCKET # 01-EOR-1, 2002-2012 ELECTRICITY OUTLOOK REPORT (2002).

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the long-run market price should converge to the LRMC.²³ At times of market surplus, the FERC approach can result in a price benchmark below the LRMC based on owning and operating new generation. At times of market shortage, the converse occurs. Hence, the choice of a benchmarking methodology can affect one's decision as to whether the affiliate contract is price reasonable and whether full recovery of the contract's cost should be allowed.

D. Overall Conclusion

We conclude that given suitable data, the FERC approach is useful for gauging the price reasonableness of a long-term contract. However, data difficulties may impede the empirical implementation of the FERC approach in some instances. As well, low contract prices due to transitory surplus can discourage generation development because the resulting price benchmark for cost recovery prevents a buying utility from offering the affiliated developer a sufficiently high contract price that can yield a competitive return on and of investment. Strict adherence to the FERC approach can therefore precipitate subsequent shortages that could have been prevented by an LRMC-based benchmark. We recommend that FERC allow evidence of the LRMC/avoided cost approach to be considered where sufficient contemporaneous and comparable contract data are not available.

In May 2003, the CPUC affirmed our recommendation in its Proposed Decision implementing the California Renewables Portfolio Standard Program, which targets 20%

²³ ML KATZ & HS ROSEN, MICROECONOMICS 385-386 (Irwin 1991).

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of California's generation portfolio to come from renewable sources.²⁴ The CPUC determined that long-term contracts will not provide an accurate measure of market prices for new resources for the near future because of the lack of a usable quantity of such contracts. Rather, "the Commission is to determine a price based on the costs associated with new generating facilities. In theory, this price and the price established [by fixed price contracts] should converge, but...the electricity market in California is not in equilibrium, rendering such convergence less likely."²⁵

E. Organization

We proceed as follows. Section II illustrates FERC's benchmarking approach with PG&E's 2001 application seeking FERC's approval of a long-term contract with its affiliate generator that may emerge under its bankruptcy reorganization plan. Our choice of PG&E's FERC application is motivated by its significant role in PG&E's reorganization plan, a painful and useful reminder of the potential and actual risks of an ill-conceived market reform. It is also motivated by the unique resource mix (hydro and nuclear), sheer size and complexity of the contract, which created practical difficulties in implementing the FERC approach. Section III discusses LRMC as a benchmark for price reasonableness. It illustrates how one may apply the LRMC approach to determine if PG&E's affiliate contract is cost prudent, and therefore is also price reasonable. Section IV concludes.

II. PRICE BENCHMARKING BY THE FERC

²⁴ Rulemaking 01-10-024, *Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development*, California Pub. Util. Comm'n (Proposed Decision, May 20, 2003).

²⁵ *Id.* at 17-18.

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A. Market-based Rate Approval for an Affiliate Transaction

Under Section 205 of the Federal Power Act, a generator affiliated with a (buying) utility may submit a long-term electricity contract price for approval by FERC as a market-based rate.²⁶ In analyzing self-dealing between the affiliated seller and buyer who may gain at the expense of the utility's customers, FERC "must ensure that the buyer has chosen the lowest cost supplier from among the options presented, taking into account both price and nonprice terms (i.e., that it has not preferred its affiliate without justification)."²⁷

FERC specifies three criteria to demonstrate lack of affiliate abuse under the market-based standard: "(1) evidence of direct head-to-head competition between the seller and competing unaffiliated suppliers in either a formal solicitation or in an informal negotiation process; (2) evidence of the prices that nonaffiliated buyers were willing to pay for similar services from the seller; or (3) benchmark evidence of the market value, based on both price and nonprice terms and conditions, of contemporaneous sales made by nonaffiliated sellers for similar services in the relevant market."²⁸

According to the first criterion, the affiliate contract meets the market value standard if it is the winning response to the buying utility's request for offers (RFO) from competing sellers, and the RFO does not preferentially treat affiliate bidding. Implementation of an RFO by the utility may range from inviting sellers to submit sealed bids to having sellers participate in auctions of various forms.²⁹

²⁶ Federal Power Act, 16 U.S.C. § 824d(a) (1994).

²⁷ *Boston Edison Company Re: Edgar Electric Energy Company* (hereafter *Edgar*), 55 F.E.R.C. ¶ 62,168 (1991).

²⁸ *Ocean State II*, 59 F.E.R.C. ¶ 62,332-62,333 (emphasis added).

²⁹ See C.K. Woo, Michael Borden, Ron Warrington and Winston Cheng, *Avoiding Overpriced Risk Management: Exploring the Cyber Auction Alternative* 141:2, PUB. UTIL. FORTNIGHTLY, 30-37 (2003); See

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According to the second criterion, the seller submits evidence that the affiliated utility is not paying more for similar service than unaffiliated buyers. Thus, if an unaffiliated buyer had just signed a 5-year contract for X MW of firm power for \$Y/MWh, an affiliate 6-year firm power transaction with approximately X MW in size and almost \$Y/MWh in price would pass the market value standard.

However, benchmark evidence based on the first two criteria may not be available. With the first approach, an RFO with the affiliate seller as an invited respondent may discourage participation by other sellers who view the RFO as a “sham” exercise. More importantly, a buyer intending to transact with an affiliated seller would be unlikely to issue an RFO at all. Even if an RFO is issued, preferential treatment of affiliate bidding, if proven, can render the RFO outcome unacceptable. With the second approach, an affiliate seller with a limited resource portfolio (e.g., one 250-MW gas turbine) may not have recently signed contracts to provide the necessary benchmarking evidence. As a result, the third approach offers a feasible alternative, so long as the affiliate seller and buyer can (1) identify comparable and contemporaneous contracts in the relevant market, (2) collect the required contract information regarding price and non-price terms, and (3) perform a benchmarking analysis of the affiliate contract.

B. A Case Study of PG&E’s Affiliate Generation Contract Proposal

Before the western power crisis of 2000-2001, PG&E was a financially strong energy utility with an investment grade credit rating of A+ by S&P (May 2000).

However, beginning in June 2000, wholesale power prices rose far above the 5.47 cents

also C.K. Woo, Rouslan Karimov and Ira Horowitz, Managing Electricity Procurement Cost and Risk by a Local Distribution Company, 32:5 ENERGY POLICY 635-645 (forthcoming 2004).

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per kWh that PG&E was authorized to charge its retail customers for electricity, forcing the utility to borrow billions of dollars to cover its power purchases.³⁰ Downgrades to below investment grade by the major credit rating agencies prevented PG&E from continuing to borrow funds, eventually leading the utility to default on various loans and lose its ability to purchase power in the wholesale market in January 2001. On April 6, 2001, PG&E filed for Chapter 11 protection under the United States Bankruptcy Code.³¹ By that time, it had incurred \$8.9 billion of power purchase costs above the amount recoverable through rates, and had accumulated billions of dollars in defaulted debts and unpaid bills.³²

As part of its plan to emerge from bankruptcy as a healthy, creditworthy company, PG&E has proposed dividing the integrated utility into four separate, stand alone businesses and transferring a portion of utility's assets to each of them: retail gas and electric distribution; electric transmission; interstate gas transmission; and electric generation. The new companies will be known, respectively, as PG&E ("Reorganized PG&E"), ETrans LLC, GTrans LLC and Electric Generation LLC ("Gen"). One of the cornerstone agreements of PG&E's reorganization plan is a long-term Power Sales Agreement (PSA) developed by Reorganized PG&E and Gen while still under the parent

³⁰ PG&E's rate for generation was frozen by AB 1890, passed in 1996, which opened the door to California's electricity market reforms. Though projected as adequate for stranded cost recovery in 1996, this rate freeze contributed to PG&E's bankruptcy when wholesale market prices surged from under \$40/MWh in 1999 and early 2000 to over \$250/MWh in early early 2001. See C.K. Woo, Debra Lloyd, Rouslan Karimov & Asher Tishler, *Stranded Cost Recovery in Electricity Market Reforms in the US*, 28:1 ENERGY—THE INTERNATIONAL JOURNAL 1-14 (2003); C.K. Woo, Debra Lloyd & Asher Tishler, *Electricity Market Reform Failures: UK, Norway, Alberta and California*, 31:11 ENERGY POLICY 1103-1115 (2003); C.K. Woo, *What Went Wrong in California's Electricity Market?* 26:8 ENERGY—THE INTERNATIONAL JOURNAL 747-758 (2001).

³¹ "Plan of Reorganization under Chapter 11 of the Bankruptcy Code for Pacific Gas & Electric Company," Case No. 01 30923 DM (Bankr. N.D. Cal September 20, 2001).

³² *Application of Electric Generation LLC for Order Accepting Power Sales Agreement and Interim Code of Conduct, and Waiving Regulations* (F.E.R.C. No. ER02-456-000) [hereinafter *Application of Electric Generation*], at 6-8.

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PG&E umbrella. Under the plan, PG&E will transfer 7,100 MW of nuclear and hydroelectric generation assets to Gen, and Gen will sell all the capacity, energy and ancillary services back to Reorganized PG&E for eleven years. For the 12th and final year of the contract, Reorganized PG&E will have rights to the capacity, energy and ancillary services of approximately half of Gen's assets. Upon termination of the PSA, Reorganized PG&E and Gen may renegotiate or extend the agreement, but neither is obligated to do so.

Under the PSA, Reorganized PG&E will purchase from Gen the capacity, energy and ancillary services associated with hydroelectric projects (3,896 MW), the Diablo Canyon Nuclear Power Plant (2,174 MW), irrigation district and water agency power purchase contracts (1,048 MW), and the Grizzly hydro contract (20 MW).³³ In a normal year, these contracts are expected to supply about 40% of Reorganized PG&E's energy needs and 70% of its ancillary service requirements. Reorganized PG&E will have the authority to schedule and dispatch the generating resources and ancillary services to best meet its load. Gen will be responsible for safely and reliably operating the generation facilities, and for maintaining high levels of availability. Reorganized PG&E's payments to Gen under the PSA will largely be driven by the availability of the units. If Gen fails to meet certain availability levels, Reorganized PG&E's payments drop. Conversely, if Gen exceeds the availability targets, Reorganized PG&E's payments generally rise.³⁴

Assuming average water conditions and taking into consideration adjustments for forecast inflation, irrigation district contract expirations, and the 50% capacity phase-out

³³ PG&E would transfer its wholesale power obligations under the Grizzly Development and Mokelumne Settlement Agreement ("Grizzly") to Bucks Creek, LLC, one of Gen's subsidiaries. Among other things, the Grizzly contract provides for certain cost-based power sales to Silicon Valley Power.

³⁴ *Application of Electric Generation*, Ex. No. GEN-1 at 4-5 (direct testimony of Roy Kuga).

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in the 12th year of the contract, Gen estimates a levelized price of electricity of \$51.90/MWh over the life of the PSA.³⁵ This price includes all ancillary services that accompany the assets. Capacity payments under the PSA are weighted to encourage Gen to provide the highest levels of availability during the peak summer months (July and August).

Gen's application to FERC for approval of the PSA as a market-based rate under FPA Section 205 underscores the complexities of using market-based benchmarking analysis as the sole basis for determining abusive self-dealing. On the surface, it seems that FERC's *Edgar* and *Ocean State II* precedents clearly lay out the conditions an applicant must meet to demonstrate its affiliate contract is at least as favorable as others in the market. However, these FERC decisions were written in the context of a single, standard, gas-fired generation unit in markets with many similarly sized and fueled units. In order to satisfy the test for the PSA, a large, unique combination of hydro and nuclear assets that is not directly comparable to any individual assets or portfolio of assets in Northern California or any other part of North America, it was necessary for the applicant to focus on the product being sold (energy, capacity and ancillary services), not the source of the supply.

FERC issued its decision on *Edgar* in 1991 and its decisions on *Ocean State II* in 1991 and 1994, long before the widespread restructuring on the electric power industry that occurred in the late 1990s or the western power crisis of 2000-2001. Back then, merchant power companies had yet to take shape, there were relatively few exempt wholesale generators, and FERC had not yet issued Orders 888 and 2000 to create open

³⁵ *Application of Electric Generation*, Ex. No. GEN-43 at 6 (rebuttal testimony and exhibits of Eugene T. Meehan in response to June 12 Commission order).

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access on the nation's transmission system.³⁶ Whereas in the late 1980s and early 1990s, utilities still generally restricted their trading and contracting to seasonal exchanges and reserves sharing with adjacent control areas, by the late 1990s power traded across large regions by utilities and speculators alike, leading to a dramatic increase in volumes and volatility. Power companies also utilized sophisticated financial hedging instruments in addition to contracting directly with physical assets. None of these developments explicitly undermines the FERC's approach to disproving abusive self-dealing, but they do point to the potential challenges in developing a comparison group of benchmark contracts and a set of unbiased assumptions.

Gen submitted the PSA to FERC for approval on November 30, 2001, and it was set for hearing. An Initial Decision recommending approval was issued 10 months after it was filed.³⁷ The next part of this paper analyzes the PSA against each of FERC's benchmarking criteria from the perspectives of PG&E/Gen, the CPUC, FERC staff and the FERC Administrative Law Judge. These criteria include the relevant geographic market, relevant product market, contemporaneous contracts, price and non-price comparison of these contracts, and market power.

i. Relevant Geographic Market

FERC characterizes the "relevant market" in geographic and product-specific terms. In its *Ocean State Power II* order, FERC states:

"Ocean State II defines the relevant market as 'the market for delivered long-term baseload capacity and energy in New England in late 1987 through 1988.' We

³⁶ Energy Policy Act of 1992, Public L. No. 102-486. *See also* RICHARD F. HIRSH, POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM 240-247. The Energy Policy Act of 1992 encouraged competition among wholesale power producers and gave states the prerogative to introduce retail competition within their borders.

³⁷ Initial Dec., *Electric Gen LLC*, 101 F.E.R.C. ¶ 63,005 (October 10, 2002), approving Gen's PSA.

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agree that the market for long-term bulk power—the same product sold by Ocean State II—is the relevant product market.

A geographic market consists of those suppliers that can supply the relevant product to a buyer or set of buyers.... [that] have the same supply choices as the [applicant]. The relevant geographic market is determined by sellers that could supply [the relevant] buyers....³⁸

Given that the PSA is a long-term power contract with baseload and peaking components serving PG&E's service territory, Gen argued in its FERC filing that, to be relevant as a benchmark, "a contract had to be deliverable on a firm basis to the PG&E service territory in Northern California."³⁹ This interpretation led Gen to exclude from consideration as possible benchmarks all contracts in the Eastern Interconnection, eastern portions of the Pacific Northwest and the Rocky Mountains, even if they had similar product characteristics and were contemporaneous with the PSA.

The CPUC disagreed with Gen's analysis of what constitutes a relevant geographic market. Staff testimony argued that "the [Gen] analysis uses too narrow a definition of the geographic market by focusing on physical deliverability of power into PG&E's service territory."⁴⁰ The CPUC concluded that this approach was not consistent with the FERC's primary goal of protecting ratepayers from abusive self-dealing because limiting the comparison group to firm contracts deliverable to Northern California inflated the benchmark price. In other words, PG&E's low variable cost hydro and nuclear generation were benchmarked against high variable cost gas-fired generation

³⁸ *Ocean State II*, 59 F.E.R.C. ¶ 62,333.

³⁹ *Application of Electric Generation*, Ex. No. GEN-2 at 11 (direct testimony of Eugene T. Meehan in support of Gen's application).

⁴⁰ *Application of Electric Generation*, Ex. No. PUC-1 at 11 (direct and answering testimony of Gurbux K. Kahlon of the California Pub. Utils Comm'n).

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resources, biasing the analysis. Since there are no comparable nuclear or hydroelectric contracts in the defined geographic market, the CPUC argued that Gen's benchmarking analysis should have included nuclear contracts from elsewhere in the United States. To support its argument, the CPUC stated that pricing for long-term contracts was less dependent on regional factors than for shorter term contracts: "Indeed, market prices for contracts up to five years in length in various regions around the country have tended to converge in the months since FERC issued its June 19, 2001 Order."⁴¹

FERC staff did not support the CPUC's case for expanding Gen's definition of the relevant geographic market. They defined the "relevant" market as "that geographic area from which sellers can deliver similar quality product to the PG&E load at a price that is lower than, equal to, or not significantly greater than the price of the PSA product."⁴² Whereas the CPUC focused on the *cost* of comparable contracts, FERC staff's assessment emphasized the comparability of the *delivered price* that a California power purchaser would face, including transmission costs. This approach eliminated from consideration as comparable any generation resources that were not price competitive at the point of delivery to meet PG&E's load, no matter how low the price at

⁴¹ *Application of Electric Generation*, Ex. No. PUC-1 at 21 (Kahlon testimony). FERC's order imposed a must-offer requirement upon all sellers throughout the Western Electricity Coordination Council (WECC) (except hydroelectric resources and capacity needed to meet WECC minimum operating reserve criteria for control areas) whenever the reserve deficiency level for California dropped below 7 percent. Most importantly, FERC required "sellers that own generation to submit bids during reserve deficiencies that are no higher than the marginal cost to replace gas used for generation (i.e., what the seller would pay for gas at the last minute) plus variable O&M costs." See *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs. Into Mkts. Operated by the Cal. Indep. Sys. Operator and the Cal. Power Exch.*, 95 FERC ¶ 61,418 ("June 19th Order") at 7. In those deficiency hours, prices for WECC spot market sales could not exceed the independent system operator's (ISO's) hourly market clearing price without justification. In non-deficiency hours, spot prices could not exceed 85% of the highest hourly ISO market clearing price of the last Stage 1 deficiency period. This FERC order is significant to our proposed use of LRMC as a benchmark for price reasonableness in that FERC already endorses the use of short-run marginal cost (SRMC) to remedy market imperfections that cause unreasonable price spikes. It is a natural extension to apply LRMC to gauge price reasonableness in the absence of usable data to implement the FERC market-based approach.

⁴² *Application of Electric Generation*, Ex. No. S-12 at 14 (prepared direct and answering testimony of Sabina U. Joe, witness for the staff of the F.E.R.C.).

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the source of generation. At a minimum, according to FERC staff, this limited the relevant geographic market to generation facilities in the Western Electric Coordinating Council (WECC) area capable of serving PG&E's service territory. FERC Administrative Law Judge Jeffie Massey, in her October 2002 decision, concurred with FERC staff and Gen that suppliers could not be considered part of the geographic market unless they could physically "supply the relevant product to the buyer or buyers."⁴³

ii. Relevant Product Market

Those contracts that passed the geographic relevancy test were subjected to a product market screen. Gen only considered contracts "relevant" if they had a similar term and expected delivery pattern as the PSA. Given that the PSA is a 12-year contract with baseload and peaking components, Gen chose to define comparable transactions as long-term bulk power contracts of 10 to 15 years in length with at least eight years of overlap with the term of the PSA period. Although Gen did not disqualify any contracts on the basis of size or technology, it did require the contracts "to have an expected delivery pattern that could equal or exceed (on a scaled basis) the expected output, based on historical averages, of the PSA."⁴⁴ This condition eliminated the following types of transactions from consideration: (1) short- or medium-term transactions because the term was not comparable to the PSA; (2) back-loaded contracts that offered a steep discount to the forward market in early years in return for an above market price in later ones; (3) wind power because its generation profile does not match that of the PSA (unreliable capacity factor) and its contract cost is much more expensive.

⁴³ *Electric Generation LLC*, 101 F.E.R.C. ¶63,005 at 31.

⁴⁴ *Application of Electric Generation*, Ex. No. GEN-2 at 12 (direct testimony of Eugene T. Meehan).

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In the end, Gen's initial screening resulted in a comparison group of 11 contracts. Nearly all of them were long-term contracts signed by the California Department of Water Resources (DWR) in 2001, when the state's utilities were hobbled by the electricity crisis and did not have the credit strength to serve as counterparties. Recognizing that using DWR contracts would raise concerns of market power and extraordinary pricing because many of the DWR contracts were signed at the height of the crisis, Gen specifically excluded from its Comparison Group "contracts signed early in [2001 that] may reflect buying panic."⁴⁵ In response to FERC's order setting the case for hearing, it revised its set of comparable contracts to include only contracts signed or amended after FERC adopted its market mitigation plan for the spot market on June 19, 2001.⁴⁶

The CPUC fundamentally took issue with Gen's screening process for determining the product market relevancy, arguing that none of the contracts in Gen's comparison group had characteristics of the PSA. For example, none of the contracts individually was equal in size to the 7,100 MW capacity of the PSA. The CPUC also stressed that because Gen's comparison group did not include nuclear or hydro resources and did not provide ancillary services, Gen's benchmark analysis was flawed and therefore invalid.⁴⁷ Instead, the CPUC proposed a portfolio of 31 contracts, including short-term contracts, affiliate contracts, power marketer-to-power marketer contracts, and contracts for delivery outside of California and outside the WECC.

⁴⁵ *Application of Electric Generation*, Ex. No. GEN-2 at 61 (direct testimony of Eugene T. Meehan).

⁴⁶ *Application of Electric Generation*, Ex. No. GEN-43 at 8-9 (rebuttal testimony and exhibits of Eugene T. Meehan in response to June 12 Commission order).

⁴⁷ *Application of Electric Generation*, Ex. No. PUC-1 at 5 (Kahlon testimony).

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Ideally, FERC staff would have preferred the PSA to have been compared to like power projects and contracts. However, they disagreed with the CPUC's position that the lack of a comparable 7,100 MW long-term contract with a similar resource mix rendered Gen's benchmark analysis invalid. Staff concluded that "the principles in *Edgar* do not blindly require a one-on-one comparison of individual projects or transactions. The PSA generation profile can be viewed as a single, integral product which can be reasonably compared against the output of another group of comparable projects."⁴⁸ Judge Massey sided with FERC staff and Gen, stating: "[The CPUC's] evidence in support of their arguments consists solely of opinion testimony which has no corroborative support, and has been successfully rebutted by [Gen] on every point."⁴⁹

iii. Contemporaneous Contracts

Market conditions change constantly in the wholesale power market, driven by such factors as weather patterns, economic conditions, fuel prices, plant outages and transmission availability. To be comparable to the PSA under FERC's guidelines, other market-based contracts must not only be serving customers in the same region with a similar type of product, they must have been signed at roughly the same time. Given that many fewer long-term bulk power contracts are signed than short-term ones, it is difficult to find a sample of exactly contemporaneous contracts with comparable price and non-price terms. In the *Ocean State II* ruling, FERC defined the relevant time period for

⁴⁸ *Application of Electric Generation*, Ex. No. S-12 at 22 (prepared direct and answering testimony of Sabina U. Joe).

⁴⁹ *Electric Generation LLC*, 101 F.E.R.C. ¶ 63,005, at 37.

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purposes of the benchmark analysis to be about 18 months, “reflecting the period during which the purchasers made their decisions to contract with Ocean State II.”⁵⁰

Based on this precedent, Gen researched market transactions that occurred in the 18 months previous to its November 2001 FERC filing. This period overlapped the months from April to November 2001, during which PG&E internally negotiated the terms of the PSA and filed it with FERC. The CPUC disputed Gen’s definition of “contemporaneous” transactions, arguing that the PSA was not scheduled to take effect until 2003, and therefore was not contemporaneous with contracts that started delivery in 2001. Furthermore, it noted that the PSA was not filed until November 2001, a time when forward power prices were lower than they were when the benchmark contracts were signed. However, FERC Staff sided with Gen on the issue, and Judge Massey dismissed the CPUC’s arguments, stating that “the CPUC made several arguments...none of which have any support, either legally or factually.”⁵¹

iv. Price Comparison Analyses

Long-term bulk power contracts are usually custom designed to reflect the unique set of price and non-price terms agreed by the transacting buyers and sellers. They are not standard contracts (e.g., a 25 MW block with 6x16 firm, next-month delivery) traded on the open market; rather, they are negotiated bilaterally and are extremely illiquid. FERC’s *Edgar* decision, which rejected Boston Edison’s benchmark analysis for its Edgar power plant, placed the burden of proof squarely on the applicant:

⁵⁰ *Ocean State Power II*, 59 F.E.R.C. ¶ 61,360 at 62,334. The specific period defined for Ocean State was late 1987 to mid-1988, further extended into 1989 on the theory that some commitments made in 1987-1988 would not result in power contracts until 1989. One should note that by today’s standard, 18 months is a relatively long period in which the market price might have surged and dived substantially.

⁵¹ *Electric Generation LLC*, 101 F.E.R.C. ¶ 63,005, at 32.

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“A comparative analysis such as the one submitted by Boston Edison can be complicated because of the widely varying price structures, operating characteristics, and non-price terms of the numerous alternatives...Moreover, because most prices are formulaic, the analysis will rely to a great extent on projections of formula variables (e.g., fuel cost, plant factors and economic indices) over the life of each project. The assumptions underlying these projections and the significance ascribed to non-price factors are critical to the analysis.”⁵²

To ensure that the PSA did not fall into the same trap that Boston Edison’s Edgar plant did, Gen used a “nominal levelized price” methodology grounded in FERC’s *Ocean State II* decision.⁵³ Gen calculated a levelized dollar per MWh price for the PSA and for each comparative contract by taking the total anticipated payments and total anticipated MWh of generation and adjusting them for timing differences using a discount rate.⁵⁴ This form of present value analysis placed front-loaded contracts (with decreasing payments over time) on the same footing as back-loaded contracts (with increasing payments over time). Gen also used a common set of assumptions for gas prices, the discount rate, the value of ancillary services and transmission loss adjustment. This resulted in a single metric, the levelized price in \$/MWh, that Gen could use to compare prices of different contracts to the PSA individually and as a portfolio.

Gen used three separate price analyses to demonstrate that the PSA was as favorable to Reorganized PG&E as any other contract or combination of contracts

⁵² *Edgar*, 55 F.E.R.C. ¶ 61,382, at 62,169.

⁵³ *Ocean State Power II*, 59 F.E.R.C. ¶ 61,360 at 62,335.

⁵⁴ Gen added a levelized charge for ancillary services to the benchmark contracts for comparability because they did not include them but the PSA’s price did.

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defined that passed its criteria for comparability. In an individual contract price analysis, Gen compared the price of each individual contract to the price of the PSA, ignoring for the moment the differences in dispatchability, availability or delivery pattern. The PSA was superior to all but two of the contracts in every gas price scenario (low, base and high). Only in the low gas price scenario were two of the contracts less expensive than the PSA.

Gen also conducted a least-cost portfolio dispatch analysis. Assuming that each of the comparable contracts was “infinitely scalable”, notwithstanding individual contractual limits on capacity, Gen constructed an “optimal portfolio” using only the lowest priced baseload and peaking contracts in the Comparison Group to replicate the energy pattern of the PSA.⁵⁵ Under all gas price scenarios, Gen demonstrated that the PSA was less expensive than the optimal alternative portfolio.

A third analysis, which allowed for market purchases and sales by the buyer in addition to the dispatch of the least cost portfolio, yielded the same result as the least-cost portfolio dispatch analysis.

Gen tested the sensitivity of the results to changes in the discount rate, inflation, gas prices, and hourly market prices. Only in the “extreme low” gas price scenario was the optimal portfolio less expensive than the PSA, and then only by less than 1% of the PSA price.

The CPUC rejected nearly all of the assumptions underlying Gen’s benchmarking analysis and declared Gen’s comparative analysis invalid. The CPUC presented an alternative portfolio of 31 contracts, each of which it said was less expensive than the

⁵⁵ Gen did not consider two contracts in the Comparison Group to be scalable. *See Application of Electric Generation*, Ex. No. GEN-43 at 10-11 (rebuttal testimony and exhibits of Eugene T. Meehan in response to June 12 Commission order).

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PSA. These included short-term contracts, nuclear contracts from the Eastern Interconnection, affiliate contracts, power marketer-to-power marketer contracts, a contract with Bonneville Power Administration, and contracts for delivery outside of California. However, Judge Massey dismissed the CPUC’s benchmark analysis as unpersuasive and criticized it for not being based on a careful assessment of Gen’s benchmark evidence: “Overall, I found...[the CPUC’s] testimony to be unduly influenced by her apparent bias against PG&E and generally uninformed.”⁵⁶

With two reservations, FERC staff accepted Gen’s finding from its price benchmarking analysis that the PSA was the lowest cost alternative available to PG&E, considering price and non-price terms. The first reservation was whether additional contracts should be included in the benchmark analysis. However, during cross-examination, FERC staff agreed that no additional contracts merited consideration for inclusion.⁵⁷

More significantly, FERC staff and the CPUC questioned whether the financial risks associated with hydroelectric assets—the volatility in generation output from year to year and the market valuation of the risk—had been properly accounted for in Gen’s pricing analysis. FERC staff stated: “This defect is not mitigated by any argument that PG&E can manage the operation of the hydropower resources through the use of storage capability to compensate for low water years and to dispatch hydropower primarily in hours when the value of energy is high because I assume that such efficient management of hydropower storage is already reflected in the historical generation data that was used

⁵⁶ *Electric Generation LLC*, 101 F.E.R.C. ¶ 63,005 at 44.

⁵⁷ *Electric Generation LLC*, 101 F.E.R.C. ¶ 63,005 at 24 (note 13).

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to develop the forecasted average hydropower generation....”⁵⁸ FERC staff argued that whereas Gen’s benchmarking portfolio consisted of gas-fired generation with a consistent energy output from year to year, the energy from hydroelectric facilities could vary greatly, leading the market to assign it a lower value than that of a gas-fired plant. Staff noted that the PSA’s price did not accurately reflect this risk because approximately 83% of the annual payment under the PSA was for available capacity, not delivered energy. As a result, a low hydro year could expose Reorganized PG&E to “enormous” financial risk because it could end up paying close to double the market price for energy, taking into account the full payment for capacity plus full payment for replacement energy.⁵⁹ Both FERC staff and the CPUC argued that the price of the PSA should be lower to reflect that risk.

Gen’s view was that hydro flows would fluctuate over the course of the 12-year contract, but that on average hydro output would tend towards the long-term mean used to calculate the PSA’s price in the benchmark analysis. Moreover, “variations in value will be less than variations in energy” because in low water years, hydro can be stored for use in high value peak hours and used to produce more ancillary services for sale in those hours.⁶⁰ Gen performed two statistical analyses to demonstrate the financial impact of hydrological variation on the PSA price and compare the risks of the optimal portfolio (gas price, fuel availability, weather-related availability risk) to the risks of the PSA. Gen concluded with a 98% probability that even when using actual precipitation data under an extremely dry 12-year hydro cycle the PSA is as favorable to Reorganized

⁵⁸ *Application of Electric Generation*, Ex. No. S-12 at 41 (prepared direct and answering testimony of Sabina U. Joe).

⁵⁹ *Application of Electric Generation*, Ex. No. S-12 at 48 (prepared direct and answering testimony of Sabina U. Joe).

⁶⁰ *Application of Electric Generation*, Ex. No. GEN-2 at 61 (direct testimony of Eugene T. Meehan).

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PG&E as the optimal portfolio. Furthermore, there was a greater than 50% chance that the actual price per MWh of the PSA would be less than the \$51.90/MWh PSA price Gen used for benchmarking purposes.

Given that neither the CPUC nor FERC staff supported their criticisms of Gen's price terms with independent analyses that quantified their meaning or impact, Judge Massey concluded that she could not give them any evidentiary weight and instead accepted Gen's position.

v. Non-Price Terms

Gen was also required to benchmark the PSA's non-price contractual terms against the Comparison Group. This included analyzing the assignment of responsibilities and risks, and the consequences of non-performance by the parties. Gen based the PSA's structure on the Master Power Purchase and Sale Agreement developed by the Edison Electric Institute and the National Energy Marketer's Association, which is the industry standard for bilateral power contracts. Gen compared the non-price terms of its PSA with those of typical, arms-length bilateral sales agreements. Those terms included availability risk (a measure of reliability), fuel price risk, dispatch control, hydrologic risk, and Diablo Canyon facility security risk.⁶¹

Gen declared that the PSA is no riskier, and in some ways less risky, than the comparison contracts entered into by the DWR. Whereas all but one of the comparison contracts are fueled by natural gas, the PSA protects Reorganized PG&E from gas price volatility through its hydro and nuclear asset portfolio. Furthermore, while some of the DWR contracts carry a risk of asset development delays, all of the assets in the PSA are

⁶¹ *Application of Electric Generation*, Ex. No. GEN-2 at 77-81 (direct testimony of Eugene T. Meehan).

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operational. Reorganized PG&E's ability to dispatch the PSA's portfolio of units allows it the flexibility to follow load, minimizing costs and its exposure to the market for balancing energy. The low variable costs of the hydro and nuclear units protect Reorganized PG&E from uneconomic purchases, while the storable nature of some hydro energy allows PG&E to dispatch more when prices are high. In contrast, some of the contracts in the comparison group have must-take provisions and floating gas prices, creating open-ended price risk for the buyer.

Of course, while the PSA does not have fuel price risk, it is vulnerable to variations in hydrological conditions. FERC staff and the CPUC took issue with the PSA's definition of "availability" as the physical operating fitness of the units, irrespective of the amount of energy that could be produced.⁶² According to FERC staff, most of the contracts in the Comparison Group require certain levels of availability but make payments based on scheduled or delivered *energy*, whereas the PSA's availability is strictly related to mechanical operability (rather than conditional on the availability of hydro resources). Reorganized PG&E bears the risk that there might not be enough water in the rivers and behind the dams to generate the needed electricity, irrespective of the operational fitness of the units. FERC staff stated: "to the extent that [the units] are 'available' under the narrow PSA definition, the buyer PG&E must still pay full capacity payments even when there is significantly inadequate generation output from the hydropower units."⁶³

⁶² The standard definition of availability is the number of hours a power plant could potentially produce electricity if dispatched (less an allowance for planned outages) divided by the total number of hours in the year (8,760 in non-leap years).

⁶³ *Application of Electric Generation*, Ex. No. S-12 at 46 (prepared direct and answering testimony of Sabina U. Joe).

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However, FERC staff acknowledged that nearly all of the benchmark assets face fuel price risk. They did not offer any analysis to quantify the potential market value discount for PSA generation volatility due to hydro conditions. In her Initial Decision supporting Gen’s position, FERC Judge Massey wrote: “When taken out of context, any one of the price or non-price terms may be less favorable than its counterpart in one or more of the Comparison Group Contracts. However, I don’t believe that is what the Commission contemplated when it ordered a Benchmark Analysis in this proceeding. The PSA must be considered as a whole—almost like a living entity—its parts interact to make it what it is.”⁶⁴

vi. Market Power Test

FERC’s final test for abusive self-dealing in affiliate transactions examines whether the applicant or its affiliates have distorted the benchmark evidence through the exercise of market power. “In particular, when a seller...is seeking market-based prices for sales to one or more affiliated traditional utilities, our concern is that the transfer price—the price the seller charges its affiliated buyers for the seller’s power—is too high.”⁶⁵

Gen addressed this concern by first pointing out that neither it nor PG&E is a party to any of the benchmark contracts, so it could not have influenced their outcomes. Second, PG&E had no incentive to artificially raise prices because it was a net buyer of power even before it sold more than 6,000 MW of generation capacity in its 1998-1999 divestment. Although PG&E’s parent, PG&E Corporation, did have control over

⁶⁴ *Electric Generation LLC*, 101 F.E.R.C. ¶ 63,005 at 50.

⁶⁵ *Ocean State Power II*, 59 F.E.R.C. ¶ 61,360 at 62,337.

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independent power assets indirectly through its wholly-owned subsidiary PG&E National Energy Group (NEG), the output of the four NEG-related power plants operating in the West was committed to long-term, fixed rate contracts. Neither FERC staff nor the CPUC presented any evidence challenging Gen's position on this issue.

C. Challenges of Applying Edgar and Ocean State II to the Current Market

The analysis in the previous section highlights the challenges of applying the market-based benchmarking enshrined in *Edgar* and *Ocean State II* to determine whether a long-term contract between affiliates is just and reasonable. Unlike standard products with near-term delivery that are tradable on the open market, large long-term contracts are less common, usually negotiated bilaterally, and customized to particular assets and the needs of one buyer. Although Gen was able to find a variety of comparable contracts because many long-term contracts were executed in response to the California debacle, the sample of potentially comparable and contemporaneous contracts may be quite small in other situations, making it virtually impossible to avoid some subjectivity and ambiguity in defining the relevant market and contemporaneous time period.

Arbitrary assumptions on key parameters such as the minimum length of a “long-term” contract can have significant effects on whether the benchmark analysis “proves” that the contract in question is at or below the market price for similar transactions or far above it. Furthermore, contract prices for the comparison group can be unduly influenced by market imperfections. Such imperfections include:

- Poor market design as exemplified by California;

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- Market power abuse by large generators as alleged by the California Independent System Operator and Governor Gray Davis;
- Falsified price information, as Dynegy and AEP have admitted to providing to publishers;⁶⁶
- Information advantage enjoyed by affiliated generators in obtaining transmission access;
- Poor price discovery due to thin trading or lack of trading of spot energy and hedge instruments (e.g., options, futures and forward contracts);
- Poor risk allocation due to a lack of hedge instruments or thin trading of such instruments; and
- Incomplete market reflected by lack of trading of long-term contracts and other hedge instruments.

The restructuring of electricity markets and rapid expansion of power trading in the late 1990s increased the complexity of the power markets and the volatility of electricity prices. A fast moving market has highly volatile prices that can render a benchmark computed using a long sample period meaningless. For instance, the precedent set by *Ocean State II* and followed by Gen in application to FERC for the PSA with PG&E is an allowance for an 18-month window to cull benchmark transactions. Since the California energy crisis and the financial troubles of the merchant power sector, an even more debilitating problem has emerged: electricity trading has dwindled to such a degree that

⁶⁶ *CFTC Subpoenas Platts for Pricing Documents*, MEGAWATT DAILY, Oct. 14, 2002, at 1.

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even standard products for relatively short terms lack liquidity, not to mention long-term contracts.⁶⁷

The result of all this ambiguity is often an inconclusive analysis, which fails to produce consensus among the stakeholders on the justness and reasonableness of the contract in question. Without reliable comparable and contemporaneous long-term contracts, FERC's market price approach to benchmarking will face enormous challenges.

III. LONG-RUN MARGINAL COST ANALYSIS

A. Benchmarking and Least Cost Procurement

The purpose of FERC's hearing on the PSA was to evaluate if PG&E had engaged in abusive self-dealing. The Administrative Law Judge concluded that based on the evidence presented, the terms of the PSA were at least as favorable as terms of comparable transactions.

In the CPUC's testimony before FERC on the PSA, the CPUC attempted on several occasions to insert the notion of cost into FERC's benchmarking framework. CPUC staff stated: "The benchmark analysis in this case should focus on measuring cost and value of the PSA relative to comparable transactions."⁶⁸

Although both FERC and state regulators agree that benchmarking is necessary for gauging the price reasonableness of a long-term electricity contract, we question if market-based comparisons are sufficient, especially when approval for full cost recovery

⁶⁷ Ken Silverstein, *Trading Places*, (April 25, 2003) available at: <http://www.utilipoint.com/issuealert/article.asp?id=1658>.

⁶⁸ *Application of Electric Generation*, Ex. No. PUC-1 at 20 (direct and answering testimony of Gurbux K. Kahlon).

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by a state regulator is at stake. For instance, although the FERC Administrative Law Judge accepted Gen's price benchmarking analysis of the PSA, we do not believe that the CPUC, in the absence of additional information, could find the PSA prudent and qualified for full cost recovery from PG&E's retail customers under the CPUC's jurisdiction. Hence, long-run marginal cost analysis, which is already in use by most states, could serve as a complementary tool for price evaluation and remove much of the ambiguity that surrounds benchmarking solely based on "comparable and contemporaneous" transactions.

B. Price Benchmarking beyond Edgar and Ocean State

We have proposed LRMC as corroborative evidence in support of FERC's market-based benchmark, if contemporaneous benchmark transactions that are sufficiently comparable in both price and non-price terms to the long-term contract in question are not available. The LRMC approach, if used as an alternative to FERC's market-based benchmark, should possess the following desirable attributes:

- It should be theoretically sound and backed by a history of successful case work in order to be acceptable to all parties.
- It should be empirically conservative, i.e., it should generate future electricity prices that err on the low side of reasonable estimates to prevent predatory pricing.
- It should only use data that do not require significant manipulation.
- Its modeling and input data should be transparent, sourced from independent sources and easily verifiable.

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- Its cost of application error should be minimal. Consider a state regulator approving a contract whose price is below a conservatively estimated benchmark. The contract is unlikely to result in rates significantly above actual spot prices during the contract’s delivery period. In other words, even if the spot prices turn out to be unexpectedly low, a contract approved on the basis of the conservative benchmark does not create unacceptably high rates that may be deemed “unjust and unreasonable” *ex post*.

C. LRMC Defined

We believe that LRMC has all of these favorable attributes. We form our opinion by first recalling the standard economic definition of LRMC: “[t]he change in long-run total cost due to the production of one more unit of output.”⁶⁹ The long-run total cost is the result of a firm making a long-run production decision using a least-cost mix of inputs to produce a given level of output. The term “long run” refers to a time horizon whereby the firm’s decision assumes all inputs (e.g., capital, energy, labor, land, and material) are variable. Since the list of inputs includes capital, the total cost includes the cost of a competitive return on and of capital.

In the context of electricity generation, the LRMC is the cost of producing an incremental output with a specific time profile. The time profile is important because electricity cannot be economically stored and must be generated in real time to meet time-varying demand. An output profile with brief periods of very high production is more costly and commands a higher LRMC than one with relatively stable production.

⁶⁹ ML KATZ & HS ROSEN, MICROECONOMICS 297.

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The LRMC approach has a conceptually sound relationship to market prices for long-term contracts. In a competitive market, the LRMC is the minimum price required to yield competitive returns to investors in new supply. If the input data used in the LRMC estimation are reflective of today's market environment, the resulting LRMC estimate will provide a useful benchmark for today's minimum price for long-term contracts. To the extent that the LRMC is based on conservatively developed estimates of input prices, the LRMC provides a conservative lower bound benchmark for judging the price reasonableness of a long-term contract.

To be sure, one can find contract prices that deviate from the LRMC estimates. Such deviations can occur simply because of market imbalances at the time or non-price terms in those contracts that differ from those underlying the LRMC estimation. For long-term contracts with identical non-price terms, price deviations from the LRMC estimate cannot persist over long periods due to market entry and exit by suppliers. A rational supplier would not consistently enter into long-term power contracts that did not yield competitive returns. Similarly, a supplier could not consistently earn an excessive return (above the competitive level) because rational buyers of long-term contracts would seek alternative suppliers who would accept a competitive return.

D. State Regulatory Experience with LRMC

State public utilities commissions (PUCs), including the CPUC, have adopted the *economic concept* of LRMC to gauge the reasonableness of a utility's power procurement plan. They have also adopted empirical estimates of LRMC based on the capacity and financing costs for a suitable mix of new gas-fired plants, the fuel efficiency of that plant

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mix, and the long-term cost of gas used to run the plants to meet the non-price terms of the utility's procurement plan.

PUCs use LRMC to determine a utility's *avoided cost*. For example, a utility has an existing plan for providing service to its customers. A utility can modify the existing plan by adopting an alternative (e.g., power purchase, construction of a new plant, and implementation of energy efficiency and demand side management programs) only to the extent that the alternative is less expensive than the utility's avoided cost. Suppose implementing a specific alternative at cost \$A would help the utility to cut \$B from the existing plan's total cost. The alternative is said to be *cost-effective* if its implementation cost of \$A is less than its avoided cost of \$B. Implementing the alternative would result in a cost saving $\$(A - B)$.

This principle has its root in the Public Utility Regulatory Policies Act (PURPA) passed by the US Congress in 1978. Section 210 of PURPA requires that the rates paid to qualifying small power production facilities (QFs) not exceed the utility's avoided (or "incremental") cost. Otherwise, they would not be "just and reasonable" to ratepayers.

States have often used LRMC to infer the long-term average price of electricity. The California Energy Commission relies on the LRMC to project the long-term average price of electricity in the state.⁷⁰ The Texas Public Utilities Commission used LRMC estimates to predict the long run market clearing prices of electricity under market competition.⁷¹ The resulting price prediction was used to forecast the levels of "Excess Costs Over "[stranded costs] in Texas. In addition, the State of Washington requires

⁷⁰ See Cal. Energy Comm'n, *2002-2012 Electricity Outlook Report*, (February 2002).

⁷¹ See Order No. 14 Ruling on Category A Issues, *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA Section 39.201 and Public Utility Commission Subst. R.25.344*, Pub. Util. Comm'n of Texas (Docket No. 22344) (2000).

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electric utilities to regularly develop and file long-range, “least cost plans” which imply the LRMC for these utilities. These plans and the LRMC guide each utility’s short-term (e.g. two-year) planning efforts and acquisition decisions, as well as help to “evaluate the performance of the utility in rate proceedings, including the review of avoided cost determinations...”⁷² According to the National Association of Regulatory Utility Commissioners’ (NARUC) *Compilation of Utility Regulatory Policy in the United States and Canada*, LRMC is used by a majority of U.S. utilities as the basis for calculating avoided costs.⁷³

The CPUC undertakes an avoided cost / LRMC view of both affiliated and unaffiliated transactions. A transaction that passes the FERC market-based benchmark does not necessarily receive the CPUC’s approval for full cost recovery. A case in point is the procurement prudence review of local distribution company Bear Valley Electric Service (BVES), a subsidiary of Southern California Water Company (SCWC).⁷⁴ On March 16, 2001, at the height of the California energy crisis, SCWC signed a five-year, \$95/MWH fixed price contract for 15 MW with 24-hour-a-day delivery. Even though SCWC’s contract was the result of competitive responses to its Request for Offers (which would have passed the FERC’s benchmark test) and the price was comparable to that of similar contracts signed by DWR, SCWC settled with the CPUC and an intervenor, resulting in a significant disallowance of the SCWC’s contract cost.

⁷² See Washington Administrative Code (W.A.C.) 480-100-238, Least Cost Planning.

⁷³ NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS, *NARUC COMPILATION OF UTILITY REGULATORY POLICY IN THE U.S. AND CANADA, 1995-1996* (1996).

⁷⁴ See C.K. Woo, Debra Lloyd and William Clayton, *Did a Local Distribution Company Procure Prudently in the California Energy Crisis?*, ENERGY POLICY (forthcoming 2004). Paper presented at Second Asian Energy Conference, “Energy Market Reform: Issues and Problems,” at Hong Kong Baptist University (Aug. 2003).

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Since then, California has signed Assembly Bill 57 into law. The bill directs “the Public Utilities Commission to review each electrical corporation’s procurement plan in a manner that assures creation of diversified procurement portfolio, assures just and reasonable rates, provides certainty to the electrical corporation in order to enhance its financial stability and credit worthiness, and eliminates the need, with certain exceptions, for after-the-fact reasonableness reviews of an electrical corporation’s prospective electricity procurement performed consistent with an approved procurement plan.”⁷⁵

On October 24, 2002, the CPUC issued Decision 02-10-062 that implements AB 57. In particular, the Decision requires California’s three large utilities to submit procurement plans for the CPUC’s approval. This should minimize litigation over cost recovery and present a reasonable allocation of procurement risk between a utility’s customers and shareholders. Furthermore, the legislation reinforces the importance of the need for a transparent benchmark for evaluating the reasonableness of long-term contracts *ex-ante* at the state level, as one of the goals of establishing cost-recovery mechanisms is to “diminish the need for after-the-fact reasonableness reviews of procurement procedures.”⁷⁶

In a recent proposed decision, the CPUC bluntly indicated its preference for cost-based benchmarking over market-based comparison. It states that “the record does not indicate that there are contracts in sufficient number or comparability to provide a basis for setting a market price. Accordingly, while the Commission will certainly consider any such contracts in determining a market price, we cannot rely significantly upon them at

⁷⁵ Assemb. B. 57 § 454.5 § 1 (c)

⁷⁶ Dec. 02-10-062, *Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Dev.*, California Pub. Util. Comm’n 53 (Interim Opinion, October 24, 2002).

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this time.”⁷⁷ Neither will the CPUC rely in any significant way on bids and unaccepted quotes as a basis for the market price referent. Rather, it will consider the LRMC of a new combined-cycle gas turbine (CCGT) as a proxy for benchmarking the value of a baseload resource, and the costs of a combustion turbine (CT) as a proxy for the value of a peaking product. In the absence of comparable long-term fixed-price natural gas contracts, the CPUC will use the cost of long-term gas hedges.

The CPUC rejected the notion that using the LRMC of proxy plants to establish the market price benchmark was inconsistent with statutory requirements or federal law. Indeed, the CPUC is of the opinion that FERC permits state commissions flexibility regarding the procedures selected to determine avoided costs. The CPUC quotes a 1995 FERC decision stating: “The Commission [FERC] has not, and does not intend in the future, to second-guess state regulatory authorities’ actual determinations of avoided costs (i.e., whether the per-unit charges are no higher than incremental costs). Rather, the Commission believes its role is limited to ensuring the process used to calculate the per unit charge (i.e., implementation) accords with the statute and our regulations.”⁷⁸ The CPUC believes that this means that even if the LRMC approach yields long-run prices that exceed a utility’s short-run avoided cost, FERC will not dispute the numbers.

E. LRMC in the Context of FERC’s Edgar and Ocean State Precedents

LRMC is a natural extension of the FERC doctrines already in place. In *Edgar*, FERC states that “the Commission must ensure that the buyer has chosen the lowest cost

⁷⁷ Rulemaking 01-10-024, *Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development*, California Pub. Util. Comm’n 16 (Proposed Decision, May 20, 2003).

⁷⁸ Rulemaking 01-10-024, 24-25, quoting *Southern California Edison Company*, California Pub. Util. Comm’n (2003), 70 F.E.R.C. ¶ 61,125 at 61,667 (1995).

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supplier from among the options presented, taking into account both price and non-price terms.”⁷⁹ To eliminate concerns about preferential pricing, FERC applies the standard of “... a benchmark of the market value of similar services based on contemporaneous data.”⁸⁰

LRMC forms such a benchmark for the following reasons. First, LRMC is conceptually a minimum price that a hypothetical supplier operating in a competitive market would charge to meet the non-price terms of the contract under review. If the contract price is close to a conservatively estimated LRMC benchmark, it is not the result of self-dealing.

Second, the input data in an LRMC estimation comes from independent sources (e.g., state and federal governments). LRMC estimates do not rely on contract price data that might have arisen from a dysfunctional market. On the contrary, they form an objective and unbiased benchmark of the all-in cost of new generation based on the available cost data for generation equipment, financing, fuel and emission offsets. Finally, LRMC estimates are based on assumptions reflective of the most recent input market conditions. Thus, LRMC estimates are contemporaneous with the contract in question.

LRMC estimates also accord with the criteria for benchmark evidence set out in *Ocean State II*. The relevant market considered in an LRMC estimation is the market for long-term contracts that replicates the output profile of the contract in question. The contemporaneousness of an LRMC estimation is self-evident from its use of the most recent input price data. Comparability is inherent in LRMC estimates because the

⁷⁹ *Edgar*, 55 F.E.R.C. ¶ 62,168.

⁸⁰ *Id.* at ¶ 62,168.

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estimates are based on the least-cost mix of CTs and CCGTs to meet the non-price terms of the contract they are being compared to. Finally, the input price data used in an LRMC estimation comes from public and independent sources, preempting the possibility that the benchmark data may be skewed by market power of a contract seller or its affiliates. *Ocean State II*, in its application to FERC, argued that a traditional cost-of-service study supported its position that it is “entitled to a higher-than-average [return on equity] because it faces greater risks than the average utility.”⁸¹

One inherently attractive feature of the LRMC approach is that the cost of error in approving a contract based on a conservatively estimated LRMC is small. For example, assume that a regulatory body approves a contract based on LRMC with an assumed natural gas price of \$3.00 per MMBTU, which is considered conservative at the time of writing when the spot and futures gas prices hover round \$5.00 per MMBTU. The question becomes: what is the effect of gas prices declining to \$2 or \$1 per MMBTU over the life of the contract, versus the effect of fuel or non-fuel price factors raising the spot price of electricity above the LRMC price? The unlikely gas price decline implies that ratepayers might end up paying slightly more than spot market purchasers. However, a spot price spike, such as the one that occurred in the California electricity crisis, can translate into a long-term rate increase and financial insolvency of utilities.

F. Case Study: LRMC Analysis of PSA’s Output Profile

We have estimated LRMC as a supplemental benchmark to gauge the price reasonableness of the PSA. The PSA’s price is said to be reasonable (from the LRMC perspective) if it is very close to the estimated LRMC using input assumptions that are

⁸¹ *Ocean State II*, 59 F.E.R.C. ¶ 62,326.

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reflective of today's market environment. These LRMC estimates quantify the minimum price that a hypothetical supplier would charge for a contract with non-price terms (e.g., contract duration, annual MW and MWh profile, and delivery location) comparable to those of the PSA. This minimum price is the price at which the supplier would earn a competitive return on its investment, given contemporaneous market prices for the inputs used to meet the PSA's non-price terms.

i. Model Assumptions

The following assumptions characterize our LRMC estimation:

- *Technology.* The output of the plants included under the PSA can be reasonably estimated using a combination of combustion turbine (CT) and combined-cycle (CCGT) units.
- *Cost and performance data.* The Energy Information Association (EIA), California Energy Commission (CEC) and Electric Power Research Institute (EPRI) have developed unbiased and reasonably accurate estimates of the plant cost and performance data for these technologies.
- *Hedging behavior.* The hypothetical competitive supplier using CT and CCGT to meet the PSA non-price terms would purchase gas futures to stabilize and improve the quality of its cash flows and earnings.⁸²

⁸² This assumption also encompasses the contract alternative known as "tolling", whereby an electricity supplier would lease generation capacity to an electricity buyer who would provide the gas and own the output of the unit. Under this alternative arrangement, it is reasonable to assume that the buyer needs to lock in a fixed price for gas to provide a fixed price agreement comparable to the PSA. Since the gas futures prices apply to both electricity suppliers and buyers, the contract alternative does not have a different LRMC. However, the assumption eliminates cases involving an electricity buyer procuring gas at spot because the fluctuating fuel cost would contradict the fixed price provision of the PSA.

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- *Financing.* The financing costs of the new plants would be consistent with the Standard and Poor's (S&P) guideline for debt to equity ratios for project developers and conservative estimates of the costs of debt and equity.
- *Supply competition.* Even though California's electricity market structure is still in flux, competing suppliers make supply-price bids based on LRMC in response to an RFO for long-term contracts with non-price terms similar to those in the PSA.

ii. Conservative Input Data

The LRMC estimates in this analysis are *quantitatively conservative* because they assume conservative input data. These assumptions include:

- *Capacity level.* The new gas-fired generation would only need to provide enough capacity to produce the estimated simultaneous peak output of the plants. This amount is almost always lower than the sum of the non-simultaneous nameplate capacity ratings. For example, the PSA includes about 7,100 MW of hydro and nuclear plants, based on the capacity ratings of the plants, but only 6,162 MW of gas fired generation (excluding ancillary service requirements), would be required in 2003 to provide the 31,708 GWh of output in the PSA.⁸³
- *Energy output level.* The output of the plants under the PSA varies from year to year. In particular, when the Diablo Canyon unit is down for planned refueling and maintenance, the PSA output drops substantially. Our hypothetical supplier's gas plant mix does not have the same long plant shut down. Normally, this drop in plant output would increase the cost per kWh of the LRMC, due to the fact that the fixed

⁸³ The recorded hourly load shape from the output of PG&E's hydro and nuclear plants in 1999 is assumed to be a normal year output shape. To account for planned changes in plant output that are already projected by PG&E, we adjusted the normal year output to match the total plant output in each of the 12 years covered by the PSA.

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costs of the gas fired plants would be spread over less output. However, in this analysis, we have made the conservative assumption that the hypothetical supplier would sell any excess power (above the PSA's output) at the LRMC. Keeping the gas plant mix's output at a level higher than the PSA's during Diablo refueling has the net effect of lowering the LRMC.

- *No site development and interconnection cost.* The LRMC estimates do not include any costs of gas, electric or water interconnection, which would typically increase the LRMC of a greenfield power project developer.
- *No gas price escalation in the later years of the PSA.* The forecasted cost of gas equals the July 2002 market prices (concurrent with the timing of the FERC hearings on the PSA) for gas futures quoted by NYMEX for delivery during January 2003 to July 2008.⁸⁴ The forecast does not include any escalation in the cost of gas for the last seven years of the contract.
- *Stable emission cost.* Estimated costs of environmental compliance are limited to market prices (current as of July 2002) for purchasing air emission offsets for planned, permitted or installed plants in California. Thus, the analysis excludes the scenario of escalating emission costs due to tightening air pollution regulations.
- *Minimal ancillary services.* The analysis assumes that the new gas-fired generation can provide the same amount of ancillary services as currently provided by the plants under the PSA by simply adding 10 percent of additional capacity to the gas-fired

⁸⁴ The NYMEX futures market provides the futures price for the cost of gas delivered to Henry Hub. We have added the historical basis point difference between Henry Hub and the PG&E City Gate during 1998 and 1999 to provide an estimated cost of gas in Northern California. We did not use the basis point spreads during 2000 and 2001 because they were much larger than historical levels. *See also Application of Electric Generation*, Ex. No. GEN-2 at 40-41 (direct testimony of Eugene T. Meehan). Gen developed its base case gas forecast from the 2001 Annual Energy Outlook gas forecast published by the Energy Information Administration. Meehan applied a levelized 47-cent basis differential based on the quoted forward basis price on Nov. 9, 2001, from Henry Hub to PG&E City Gate.

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generation portfolio. The 10 percent is comprised of seven percent for operating reserves and three percent for regulation. This conservatively assumes that the new gas fired plants do not incur variable costs in providing regulation or spinning reserves (which is normally about 50% of the total reserves cost). The resulting ancillary services cost is 2.4% of the LRMC estimate. In contrast, the actual average ancillary services cost paid by the California Independent System Operator exceeded 5% of the per MWh energy cost from 1998-2001.⁸⁵

- *No real power loss.* The analysis does not include any provision for real power losses in calculating the LRMC. The PSA establishes a price for power *delivered* to Reorganized PG&E load.⁸⁶ Under the terms of the California ISO tariff, each generator in the California control area is required to provide an additional amount of power to compensate for real power losses on the transmission system. The actual loss factor varies hourly, but can be as high as 4% of generator output. This analysis does not assume any additional generation to provide real power losses.
- *No risk premium charged by the seller.* The financing assumptions used in these LRMC estimates do not include any risk premium that can be observed in long-term contracts in the Western markets. We have used financing assumptions that reflect a well functioning bulk power market with less risk than exists today. When faced with market reality (e.g., transmission constraints, long-lead time and uncertainty in regulatory approval and plant construction), a rational supplier would add a risk premium to its required return to derive the LRMC as the minimum price for a long-

⁸⁵ California Independent System Operator, *Market Analysis Report for November and December 2002*, Table 10, available at <http://www.caiso.com/docs/2000/07/27/2000072710233117407.html>.

⁸⁶ *Application of Electric Generation*, Ex. No. GEN-1 at 4-6 (direct testimony of Roy Kuga).

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term contract. This analysis assumes that merchant generators have ready access to capital markets at reasonable costs, two conditions that do not apply today.

iii. Computation Method

The process to quantify the LRMC of replicating the output of the assets included in the PSA involves the following steps:

- (1) Establish the normal hourly profile of output for the assets included in the PSA.
- (2) Find a suitable least-cost mix of new generators that can produce the same output profile.
- (3) Compute the cost per MWh of the mix, with the result being the LRMC of producing the energy from the plants included under the PSA.
- (4) Add the cost of providing capacity for contingency reserves and regulation to develop a final LRMC estimate.
- (5) Add the cost of acquiring the necessary emissions offsets.⁸⁷
- (6) Test the sensitivity of the LRMC estimates to each of the cost input assumptions.

Figure 1 below shows how the key data assumptions are used to compute the LRMC estimate. The top of the figure shows the PSA hourly output pattern based on the 1999 recorded generation pattern (consistent with Gen's testimony) and the annual output under the PSA. The five categories of publicly available cost data used in the analysis are:

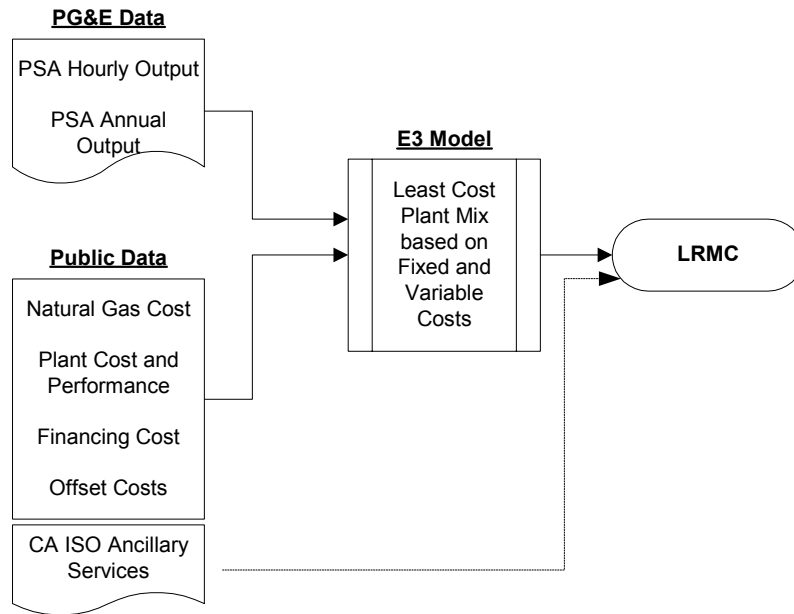
⁸⁷ Since the costs of emissions offsets vary with plant output, they are included in the dispatch analysis in step (2).

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- (1) Gas futures prices. These are used to forecast the energy cost component of the LRMC. We also use historic data from 1998 until 1999 to calculate the differences in gas cost by location.
- (2) Gas-fired generation plant cost and performance data. Along with the financing cost, the plant cost data are used to compute the capacity cost component of the LRMC. When applied to the gas price data, the performance data help derive the energy cost component of the LRMC.
- (3) The cost of financing.
- (4) The cost of purchasing emissions offsets.
- (5) Ancillary service requirements. This is the amount of additional capacity needed to “self-provide” operating reserves and regulation requirements for the gas-fired plant output.

Using the cost data, we selected the mix of CT and CCGT to produce the least cost output profile, i.e., the minimum sum of the fixed costs for plant purchase, financing and fixed O&M that do not vary with the MWh output of the installed capacity, and the variable costs for fuel, variable O&M and emission offset that vary with the MWh output. We included additional generation plant to provide the ancillary services for the load that is currently served by PG&E’s hydro facilities. Hence the total long-run cost is (a) the cost of meeting the output profile plus (b) the cost of providing ancillary services. The LRMC is this total cost levelized over the annual MWh output of the assets under the PSA.

Figure 1: LRMC Estimation Process



iv. Major Finding

Our estimates of the LRMC of replicating the output and ancillary services self-provided by the generation assets included under the PSA range from a low of \$53.67 per MWh using the *EPRI advanced* turbines, to a high of \$57.84 per MWh using the *EIA advanced* turbines. Table 1 below summarizes the levelized cost (in Year 2003 dollars) for each of the five CT-CCGT pairs.

Table 1: LRMC using Alternate Generation Plant Cost and Performance Data.

CT-CCGT specification by data source	LRMC Levelized Cost (\$/MWh. Year 2003 dollars)
EIA Conventional Turbines	\$55.80
EIA Advanced Turbines	\$57.84
EPRI Conventional Turbines	\$53.99
EPRI Advanced Turbines	\$53.68
CEC Turbines	\$55.10

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Gen estimates that the levelized rate under the PSA would be \$51.90 per MWh. This rate is 3% below the LRMC values shown in the table above.⁸⁸ In light of these LRMC estimates, our major finding is that the PSA rates are reasonable under an LRMC benchmark because they are lower than the per MWh cost of building and operating the least-cost mix of new generation facilities capable of replicating the output profile of the facilities covered under the PSA.

v. Sensitivity Analysis

The finding that the PSA is price reasonable when compared to conservatively estimated LRMC is robust across a wide range of reasonable input assumptions. It would take an unlikely combination of extremely low cost forecasts to bring the LRMC below the rates in the PSA. Adopting a reasonably low cost forecast for a single input (construction, gas, or financing) would not alter the conclusion that the rates in the PSA are below a conservatively estimated LRMC.

For example, generation capital costs would have to decline by about 11% below the already low plant cost assumption from the *EPRI advanced* case to make the LRMC estimate equal to the cost of the PSA. In other words, one would have to be able to buy the *EPRI advanced* CTs for less than \$342 per kW and CCGTs for less than \$456 /kW in order for the LRMC to compare with the PSA rates. Alternatively, the levelized 12-year gas price would have to drop by more than 5.8%, or \$0.25/MMBtu, to bring the LRMC down to the cost of the PSA. Finally, the after-tax financing cost would have to drop from a weighted average cost of capital (WACC) of 9.62% to 8.27%, which is comparable to the WACC for regulated utilities, in order for the LRMC to converge to

⁸⁸ 3% [= (1.0 – (51.90/53.68))] to 10% [= (1.0 – (51.90/57.84))].

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the PSA rates.⁸⁹ It is very unlikely that a new gas-fired generation project could be developed and financed to supply power in California under any one of these low cost assumptions.

IV. CONCLUSION

Price benchmarking is here to stay, irrespective of the future direction of the electricity sector. A continuation of the *status quo* requires benchmarking of affiliate transactions by FERC and both affiliate and non-affiliate transactions by state regulations. An acceleration of market reform and deregulation does not remove the need for price benchmarking due to concerns of market imperfections. Reversal of market reform and deregulation expands regulatory control and oversight, including price benchmarking.

At the state level, the price reasonableness test aims to determine procurement prudence. Whether prudence is based on an *ex ante* benchmark, as mandated by AB 57 in California, or an *ex post* reasonableness review, LRMC at contract signing is a commonly used benchmark. As we have shown, states use LRMC for a wide range of purposes, including benchmarking avoided cost, determining the most cost-effective mix of generation resources in utility integrated resource planning, and setting renewable resource price benchmarks.

At the federal level, price benchmarking is mainly used to determine if self-dealing has occurred in affiliate transactions. Absent competitive procurement and arms-length negotiations, the benchmark is the price of the contracts that are contemporaneous and comparable to the one in question, assuming the non-price terms of the contract in

⁸⁹ The regulated utility WACC in Major Rate Case Decisions: January to March 2002 (study by Regulatory Research Associates) was 8.51 percent.

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question are at least as favorable as those of similar arms-length contracts and the utility has not manipulated the benchmark through the exercise of market power. As a market-based test, it makes no direct reference to cost, including LRMC.

Our proposal of an LRMC-based benchmark provides a clear and easy-to-understand test: If the contract's price is less than a conservatively estimated LRMC, the contract is *per se* price reasonable. It aligns the federal and state approaches to price benchmarking of long-term contracts.

This alignment should occur because FERC has already shown that it is not averse to using marginal cost in determining price reasonableness. In its June 19, 2001, West-wide market power mitigation order, FERC invoked a single market clearing price with must-offer and short-run marginal cost bidding requirements for sales in the California ISO's spot markets in reserve deficiency hours, i.e., when reserves are below seven percent in California.⁹⁰ It would be but one small and natural step to extend FERC's use of short-run marginal costs for price capping to long-run marginal costs for benchmarking a long-term contract, when the FERC's extant market-based approach is impractical due to lack of suitable data.

Today's wholesale electricity prices are highly volatile and uncertain. This makes FERC's market-based benchmark test for long-term contracts also highly uncertain. However, for short-run contracts (less than 5 years), we concur that there is no practical substitute for the market-based benchmark, when comparable and contemporaneous contracts exist. Longer run contracts (beyond 10 years) tend to have much more stable prices. In one sense, this can make benchmarking based on market prices easier, if a liquid, workably competitive market for long-term contracts exists. However, if such a

⁹⁰ 95 F.E.R.C. ¶ 61,148 at 7.

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market is not available, a conservatively estimated LRMC can provide an effective surrogate benchmark to determine the reasonableness of long-term contract prices between affiliates.