PUBLIC VERSION
PROTECTED MATERIALS REDACTED

Exh. No. CAL-634

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Public Utilities Commission of the State of California	)	
Complainant,	)	
v.	)	
Sellers of Long-Term Contracts to the California Department of Water Resources	)	
Respondents.	)	Docket Nos. EL02-60-007 and EL02-62-006 (Consolidated)
	)	
California Electricity Oversight Board	)	
Complainant,	)	
v.	)	
Sellers of Energy and Capacity under Long-Term Contracts with the California Department of Water Resources	)	
Respondents.	)	
	)	

PREPARED DIRECT TESTIMONY OF METIN CELEBI, PH.D.
ON BEHALF OF THE CALIFORNIA PARTIES

May 19, 2015

I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

Q. What is your name and what is your business address?

A. My name is Metin Celebi. My business address is 44 Brattle Street, Cambridge, MA.

Q. By whom are you employed and in what capacity?

A. I am a Principal at The Brattle Group, an economic and management consulting firm with four offices in the United States (Cambridge, Massachusetts; Washington, D.C.; San Francisco, California; and New York, New York) and three in Europe (London, Rome and Madrid).

Q. Would you please summarize your educational and professional qualifications and experience?

A. I hold a Ph.D. in Economics from Boston College with a dissertation on transmission investment and power system modeling, a Masters in Economics from Bilkent University in Ankara, Turkey, and a Bachelor of Science in Industrial Engineering from Middle East Technical University (METU) in Ankara, Turkey. For the last fifteen years, I have been employed as a consultant in the electric power industry. My primary expertise is in forecasting of energy and capacity prices, resource planning, and analysis of environmental and climate policy. My resume is attached as Exh. No. CAL-635.

Q. What is the purpose of your direct testimony?

A. I analyze the "down the line" economic burden on California consumers caused by the Shell Contract[1] and Iberdrola Contract,[2] as well as the entire portfolio of CDWR Long-Term Contracts executed during the Crisis in Western energy markets. I also summarize the key terms of the Shell and Iberdrola Contracts.

Q. What do you understand the phrase "down the line" burden to mean in the context of this proceeding?

A. I understand that one of the issues the Commission has set for hearing is whether the prices in the Shell and Iberdrola Contracts harmed the public interest, as measured by the "difference 'down the line' between having the contracts at issue in effect and not having them in effect."[3] I further understand that the Supreme Court has defined this "down the line" burden to mean the "the disparity between the contract rate and the rates consumers

---

[1] "Shell Contract" refers to the long-term energy contract the California Department of Water Resources (CDWR) entered into with Coral Power L.L.C. (Coral), now known as Shell Energy North America (US), L.P., on May 25, 2001. References to either Shell or Coral are to the same entity.

[2] "Iberdrola Contract" refers to the long-term energy contract CDWR entered into with PacifiCorp Power Marketing, also known as PPM Energy, Inc. (PPM), and now known as Iberdrola Renewables, LLC, on July 6, 2001. References to either Iberdrola or PPM are to the same entity.

[3] *Public Utilities Commission of the State of California v. Sellers of Long-Term Contracts to the California Department of Water Resources*, 149 FERC ¶ 61,127 at P 20 (2014) (*Order on Remand*).

would have paid (but for the contracts) further down the line, when the open market was no longer dysfunctional."[4]

Q. Would you please briefly summarize the conclusions of your analyses?

A. I conclude that the Shell and Iberdrola Contracts, negotiated and executed before resolution of the Crisis, each imposed an excessive "down the line" economic burden on California consumers relative to prices CDWR could have obtained for substitute power after the elimination of the pervasive market failures. I quantify the down the line burden as $2.14 billion ($1.37 billion principal plus FERC interest) for the Shell Contract and $875 million ($601 million principal plus FERC interest) for the Iberdrola Contract. My conclusions are supported by three separate analyses, summarized in turn below.

First, I confirmed that the Shell and Iberdrola Contract prices were substantially higher than the prices in comparable contracts executed in the September 2001 – December 31, 2002 post-Crisis period. [redacted]

[4] *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County*, 544 U.S. 527, 552-53 (2008).

[redacted]

Next, I quantified the "down the line" economic burden caused by the Shell and Iberdrola Contracts by comparing CDWR's actual payments to the payments it would have made under post-Crisis forward market prices for comparable energy products and delivery volumes. The forward prices reported by energy brokers during trading days in September 2001 – adjusted to account for differences in non-price terms in the CDWR contracts – represent my best estimate of the market prices that would have been available to CDWR for substitute power after the Crisis ended, and thus serve as the most appropriate reference point for quantifying consumer harm. Based on the forward prices reported in September 2001, I derived market prices for products comparable to those delivered under the Shell and Iberdrola Contracts for each month from October 2001 through the end of their terms. I then evaluated CDWR's actual payments for energy delivered October 2001 onward in relation to the payments it would have made under the post-Crisis forward market prices for the same deliveries.

[5] The California IOUs are Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE).

For the Shell Contract, I estimate a down the line economic burden of $2.14 billion ($1.37 billion principal plus FERC interest) (see Figure 12). For the Iberdrola Contract, the down the line burden is $875 million ($601 million principal plus FERC interest) (see Figure 13).

I then corroborated my down the line findings with a separate analysis comparing the Shell and Iberdrola Contract prices with estimated prices based on the underlying cost elements of producing electric power as of the contract execution dates (May 25, 2001 for Shell and July 6, 2001 for Iberdrola). In a well-functioning market, a seller could not reasonably expect to receive substantially more than such a fundamentals-based price. I used market simulation software to estimate locational marginal prices for near-term deliveries (2001 – 2004), and developed prices consistent with the costs to build and operate a new gas-fired combined-cycle plant (long-run marginal costs) for the later year deliveries (2005 – 2012). Comparing projected payments under these fundamentals-based prices to payments under the contract prices, I estimate a burden of $779 million for the Shell Contract (see Table 8), and $371 million for the Iberdrola Contract (see Table 9) (both figures with FERC interest through May 2015).

Finally, to demonstrate in fuller extent the burden placed on California by the Crisis, I extended my post-Crisis forward market price analysis to the approximately 50 long-term contracts CDWR executed when the markets were dysfunctional. I estimate the economic burden caused by all CDWR Long-Term Contracts relative to post-Crisis prices as $24.49 billion ($15.93 billion principal plus FERC interest) (see Figure 24).

Q. How is the remainder of your testimony organized?

A. My testimony is organized as follows: In Section II, I summarize the key terms in the Shell and Iberdrola Contracts, and describe the actual costs and energy deliveries under the contracts. Section III sets forth my "down the line" economic burden analysis for the Shell and Iberdrola Contracts. Finally, in Section IV, I calculate the burden imposed on California consumers by all CDWR Long-Term Contracts executed in the Crisis. My conclusions are summarized in Section V.

II. SUMMARY OF SHELL AND IBERDROLA CONTRACTS

A. The Shell Contract

Q. When did CDWR enter into its long-term contract with Shell?

A. The Shell Contract[6] was executed on May 25, 2001 and ran for a term of eleven years, ending June 30, 2012. Exh. No. CAL-636 provides a detailed description of the key terms in the Shell Contract with references to the applicable contract provisions. I summarize some of those key terms below.

[6] Exh. No. CAL-31.

Q. What were the Shell Contract prices?

A. Prices were fixed through 2005, but consisted of different prices for different periods as follows:

May 24, 2001 – May 31, 2001:	$169/MWh
June 1, 2001 – Oct. 31, 2001:	$249/MWh
Nov. 1, 2001 – June 30, 2002:	$115/MWh
July 1, 2002 – Dec. 31, 2003:	$169/MWh
Jan. 1, 2004 – Dec. 31, 2005:	$72.87/MWh

Starting January 1, 2006, the contract converted to an indexed pricing arrangement with a $25.16/MWh fixed charge (applied to fixed energy deliveries) plus fuel costs. The fuel costs were indexed to gas prices at a contract heat rate of 7.25 MMBtu/MWh.

Q. What energy products and quantities were to be delivered under the Shell Contract?

A. The contract provided for delivery of up to 850 MW of firm energy at various quantities at different points in time as described in Exh. No. CAL-636. The base contract quantities included between 100 and 400 MW of energy during each "peak hour"[7] for the entire contract term, and starting in

[7] "Peak hour" energy, also known as "6x16" product, refers to energy delivered during the hours 07:00 through 22:00 Monday through Saturday, excluding NERC holidays.

July 2002, 100MW of “clock hour”[8] energy for the remainder of the contract term. In addition to the base quantities, Shell had the option to increase peak hour volumes by 175 MW from July 2003 through the remainder of the contract term, and another 175 MW from July 2004 onward, for a total increase of 350 MW for each peak hour. During the months of November, December, March, April, and May of each year (excluding 2001), deliveries for each component of the base and additional quantities reduced by 50%. The contract provided flexibility to both Shell and CDWR to adjust delivery quantities on a pre-scheduled basis, as discussed later in my testimony and summarized in Exh. No. CAL-636.

Q. What delivery locations were specified in the Shell Contract?

A. The contract specified three delivery locations: NP-15[9], SP-15[10], and ZP-26.[11] Shell retained substantial flexibility in choice of delivery location, as discussed later in my testimony and summarized in Exh. No. CAL-636.

---

[8] “Clock hour” energy, also known as “7x24” product, refers to energy delivered 24 hours per day, seven days per week, including holidays.

[9] NP-15 refers to North of Path 15, or that part of the ISO north of the major transmission link called Path 15.

[10] SP-15 refers to South of Path 15, or that part of the ISO south of the major transmission link called Path 15.

[11] ZP-26 refers to the area between Path 15 and Path 26 in California.

Q. What was the generation source for energy delivered under the Shell Contract?

A. The contract was not tied to any specific generation source, meaning that Shell could fulfill its delivery obligations solely from the market, with the exception that CDWR could require Shell to deliver 500 hours of energy annually from each of the five 43 MW natural-gas-fired combustion turbines (CTs) known as the Wildflower Peaking Units. Prior to Shell's negotiations with CDWR, Shell had entered into agreements with the California Independent System Operator Corporation (ISO) in late 2000 to install the Wildflower units. Due to Shell's concerns with the ISO's creditworthiness, the units eventually became part of Shell's contract with CDWR,[12] and CDWR took on the obligation to pay Shell a capacity payment of $358,000 per month (or approximately $100/kW-yr) from July 2002 – December 2005 for each Wildflower unit that was online during that period. For each facility that failed to achieve commercial operation by August 1, 2002, CDWR had sole discretion to reduce the contract quantity by 43 MW. If CDWR exercised this discretion, Shell then had the right to determine the product (6x16 or 7x24) to which the reduction was applied.

---

[12] Prepared Supplemental Direct Testimony of Ronald O. Nichols on behalf of the California Parties, Exh. No. CAL-200 at 14.

Q. Do you know the actual payments and energy volumes delivered under the Shell Contract for its entire term?

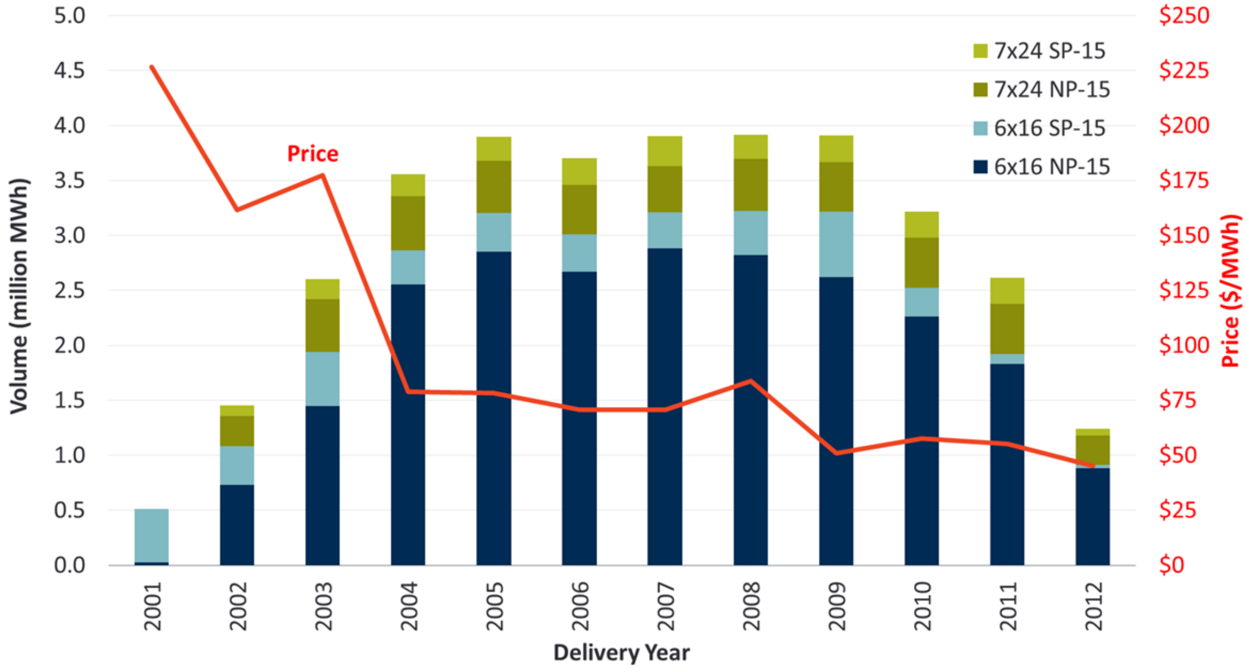
A. Yes, CDWR paid Shell approximately $2.85 billion for 34.5 million MWh of energy at an average "all-in" cost of $82.51/MWh.[13] "All in" cost means total costs for all payments under the contract, divided by total energy deliveries. Deliveries consisted of both on-peak (6x16) and clock-hour (7x24) products. 82% of planned deliveries were to NP-15, with the remaining energy delivered to SP-15.[14] Figure 1 shows the annual delivery volumes by product and location, along with average annual prices.

---

13 Prepared Direct Testimony of John Pacheco on behalf of the California Parties, Exh. No. CAL-214 at 16 (Pacheco Direct Testimony); Exh. No. CAL-216 (summary of Shell contract deliveries and payments).

14 Exh. No. CAL-216.

Figure 1
Annual Volume and All-in Prices in Shell Contract



B. The Iberdrola Contract

Q. When did CDWR enter into its long-term contract with Iberdrola?

A. The Iberdrola Contract[15] was executed on July 6, 2001. The delivery term ran from July 29, 2001 through June 30, 2011. Exh. No. CAL-637 provides a detailed description of the key terms in the Iberdrola Contract with references to the applicable contract provisions. I summarize some of those key terms below.

---

[15] Exh. No. CAL-41.

Q. Please describe the Iberdrola Contract prices.

A. Prices were fixed at $70/MWh through December 2002. Starting January 2003, the entire contract converted to a dispatchable arrangement with various fixed charges, as well as fuel and other variable costs dependent on the energy volumes CDWR scheduled for delivery. As part of this arrangement, CDWR paid a fixed "capacity charge" of $15/kW-month (or $180/kW-yr) at the "Contract Delivery Rate," as defined in the contract, regardless of the quantity of power actually delivered. While referred to as a "capacity charge," the $15/kW-month charge is better viewed as a component of the fixed portion of the total energy payment once the contract converted to a dispatchable arrangement. Capacity charges in the typical sense are costs paid by a buyer to have a specific unit owned by the seller available to meet the buyer's energy requirements. Capacity charges thus are typically associated with contracts tied to a specific generation unit which allow the buyer control over the unit providing the generation. As explained below, the Iberdrola Contract was not tied to a specific generation unit; the contract power could come from multiple resources.

Q. What energy products and quantities were to be delivered under the Iberdrola Contract?

A. The Contract Delivery Rate was set at 150 MW from the start of the term through June 30, 2002; 200 MW from July 1, 2002 through June 30, 2004;

and 300 MW for the period July 1, 2004 through the end of the contract term. Prior to January 1, 2003, deliveries were for the full Contract Delivery Rate on a flat 7x24 basis. Starting January 2003, when the contract converted to a dispatchable arrangement, CDWR could request adjustments on a monthly, daily and hourly basis, subject to certain restrictions and additional costs. The contract also provided Iberdrola various options to reduce delivery volumes which are discussed in more detail later in my testimony and summarized in Exh. No. CAL-637.

Q. What delivery locations were specified in the Iberdrola Contract?

A. The contract specified COB[16] as the primary delivery location, with an allowance for Iberdrola to deliver up to 50 MW of energy to NP-15 on a monthly scheduled basis, at Iberdrola's election, and another 50 MW on a daily pre-scheduled basis.

Q. What was the generation source for energy delivered under the Iberdrola Contract?

A. The Klamath Cogeneration Facility, a 484 MW natural-gas-fired combined-cycle plant located in Klamath, Oregon (Klamath Falls) was specified as one potential energy source; however, the contract expressly stated that Iberdrola could provide the energy from other resources as well.

---

[16] COB refers to the California Oregon Border interface with the ISO.

Q. Do you know the actual payments and energy volumes delivered under the Iberdrola Contract for its entire term?

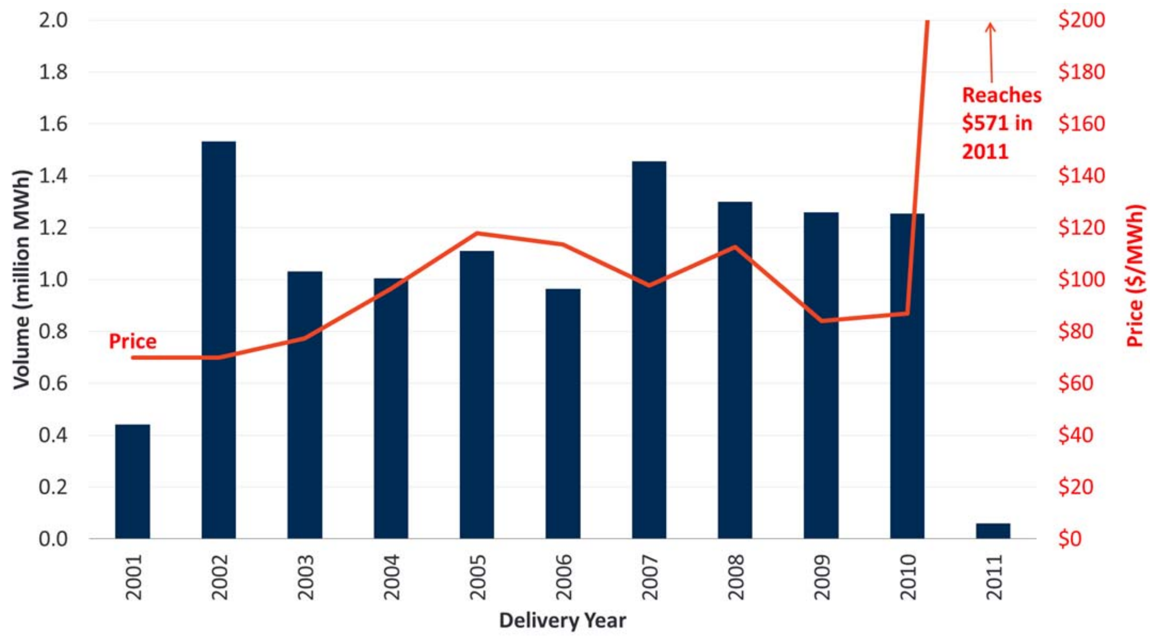
A. Yes, CDWR paid Iberdrola approximately $1.10 billion for 11.53 million MWh of energy at an average all-in cost of $95.50/MWh.[17] Almost half ($495 million) of the total costs were in the form of fixed capacity and fixed operations and maintenance (O&M) charges.[18] I understand that most (if not all) of the deliveries were made at COB.[19] The products delivered until December 2002 were flat clock-hour deliveries (7x24), while delivery volumes starting in January 2003 were dispatchable and subject to reductions by both CDWR and Iberdrola. Figure 2 shows the annual delivery volumes and all-in prices. Note that the all-in levelized price in 2011 was high at $571/MWh as a result of significantly lower volumes of energy delivered while CDWR continued to pay the same monthly fixed charges.

[17] Pacheco Direct Testimony, Exh. No. CAL-214 at 16-17; Exh. No. CAL-217 (summary of Iberdrola Contract deliveries and payments).

[18] Exh. No. CAL-217.

[19] Pacheco Direct Testimony, Exh. No. CAL-214 at 17.

Figure 2
Annual Volume and All-in Prices in Iberdrola Contract



III. ANALYSIS OF THE "DOWN THE LINE" ECONOMIC BURDEN CAUSED BY THE SHELL AND IBERDROLA CONTRACTS

Q. Please describe the methods you used to analyze the "down the line" economic impacts of the Shell and Iberdrola Contracts.

A. I analyzed the economic impacts caused by the Shell and Iberdrola Contracts using three separate methods. I first compared the Shell and Iberdrola Contracts to long-term contracts executed when the Western markets were no longer dysfunctional. Next, based on forward prices reported by brokers after the markets normalized, I derived post-Crisis forward market prices for the products delivered under the Shell and Iberdrola Contracts, and compared CDWR's actual payments to the payments it would have made under the post-Crisis prices for the same deliveries. Finally, I examined the difference between the contract prices and estimated prices for comparable products based on expected market fundamentals in the underlying cost elements that go into producing electric power as of the contract execution dates.

A. Comparison to Post-Crisis Long-Term Contracts

Q. Let's begin with your assessment of other long-term contracts. What types of long-term contracts did you look for to compare to the Shell and Iberdrola Contracts?

A. I looked for long-term contracts with non-price terms similar to the Shell and Iberdrola Contracts executed in the months immediately following the end of the Crisis. Specifically, I searched for contracts that satisfied the following minimum comparability criteria:

- Execution date between September 1, 2001 and December 31, 2002;
- Term of one year or longer;
- Product type of on-peak (6x16), clock-hour (7x24) or dispatchable energy (products provided under the Shell and Iberdrola Contracts);
- Delivery location of NP-15, SP-15, ZP-26, or COB (delivery locations specified in the Shell and Iberdrola Contracts).

I excluded from consideration non-firm energy sales, contracts sourced by renewable energy sources, and contracts providing less than year-round power (e.g., contracts providing energy for summer months only). Within the data set returned by my search criteria, I further considered additional non-price terms such as fixed price versus tolling, delivery location flexibility and volumetric options.

Q. Why did you limit your review to long-term contracts executed between September 2001 and December 2002?

A. I chose September 2001 as the start date based on my observations set forth later in this section that the dysfunction that pervaded Western energy markets when the Shell and Iberdrola Contracts were negotiated and executed had subsided by that time. I chose December 31, 2002 as the end date for my analysis based on my assessment that the period through 2002 was a reasonable period against which to compare contracts executed in May and July 2001.

Q. What data sources did you review to locate potentially comparable long-term contracts?

A. I reviewed three separate data sets: (1) other long-term contracts produced by Shell and Iberdrola in discovery in this proceeding; (2) long-term contracts executed by the California IOUs; and (3) information publicly available in the FERC EQR database. I describe my findings from each of these data sets below.

Q. Did Shell execute any comparable post-Crisis long-term contracts?

[redacted]

---

20 Exh. No. CAL-638 (PROTECTED); Exh. No. CAL-639 (PROTECTED).

[redacted]

Q. Did Iberdrola execute any comparable post-Crisis long-term contracts?

[redacted]

[redacted]

[redacted]

Q. Did the California IOUs execute any comparable post-Crisis long-term contracts?

[redacted]

[redacted]

[redacted]

[redacted]

Q. You previously stated that you also reviewed the FERC EQR database for comparable post-Crisis contracts. What is the FERC EQR database?

A. Per Order No. 2001, the Commission required public utilities and power marketers that engaged in sales transactions to file quarterly reports that summarize all contracts, products and transaction information for short-term and long-term market-based and cost-based power sales.[22] The

[22] Revised Public Utility Filing Requirements, Order No. 2001, 67 FR 31043, FERC Stats. & Regs. ¶ 31,127 (April 25, 2002).

reported information is maintained in a searchable and downloadable online format known as the EQR database.[23]

Q. Did you query the EQR database for data related to post-Crisis long-term contracts?

A. Yes. My search of the EQR database identified 32 potentially comparable contracts. The reported information for these contracts demonstrated all-in prices (on average $60/MWh during the period 2002 – 2013) significantly lower than the Shell and Iberdrola Contract prices. However, due to various observed anomalies and gaps within the EQR data, I did not consider the reported information a reliable metric to compare against the Shell and Iberdrola Contracts. I observed three significant problems with the EQR data set. First, the reported information was incomplete for many of the contracts. Second, certain of the reported energy prices were unrealistically low or high (all-in prices ranged from $3.69/MWh to more than $1,000/MWh). And finally, the database lacked key data points such as whether the contracted energy was supplied by renewable generation sources, or whether the energy was must-take or dispatchable.

[23] See http://www.ferc.gov/docs-filing/eqr/data/database.asp

Q. Have you quantified the economic burden caused by the Shell and Iberdrola Contracts based on the post-Crisis long-term contracts that you reviewed?

A. No. My review of post-Crisis long-term contract data confirmed that the Shell and Iberdrola Contracts were very highly priced as compared to long-term contracts executed in the September 2001 – December 2002 period (including the contracts Shell executed with other buyers). However, due to limitations in the number and type of contracts executed during the relevant post-Crisis period, and the available data concerning them, I did not attempt to determine a cost of substitute power in the absence of the challenged contracts based solely on these post-Crisis contracts. I instead calculated a cost of substitute power based on forward prices reported by the major brokers after the Crisis ended. The forward prices reported during trading days in September 2001 – adjusted to account for differences in non-price terms in the CDWR contracts – represent my best estimate of the market prices that would have been available to CDWR for substitute power when the markets were no longer dysfunctional.

B. Comparison to Post-Crisis Forward Market Prices

Q. Please define the term "post-Crisis forward market prices" as used in your testimony.

A. Post-Crisis forward market prices are my estimate of the prices that would have been available to CDWR for products comparable to those delivered under the Shell and Iberdrola Contracts after the elimination of the pervasive market failures of the Crisis period.

1. Derivation of Post-Crisis Forward Market Prices

Q. How did you derive post-Crisis forward market prices?

A. I derived post-Crisis forward market prices for the products in the Shell and Iberdrola Contracts based on the forward prices of block strip products reported by the major brokers active in the Western electricity markets – TFS Energy (TFS) and Natsource – during trading days in September 2001. The forward prices reported by TFS and Natsource in September 2001 represented the brokers' assessment of where the market was at the end of each trading day based on their discussions with market participants about potential or actual transactions and other information they deemed relevant. Separate prices were reported each trading day for different products (e.g., on-peak or off-peak) at various delivery locations (e.g., NP-15, SP-15, COB) for different delivery periods. As of September 2001, TFS reported forward prices for monthly deliveries for September 2001 – January 2002, quarterly deliveries for Q4 2001 – Q4 2002, and annual deliveries for 2003 – 2005.

Q. Why do you consider reported forward prices an appropriate measure of the cost of substitute power "down the line" once the open markets were again functional?

A. Reported forward prices represent a reasonable estimate at a particular point in time of the market price for future deliveries of energy products at a specified delivery location and date. Of course, these prices change from day to day as shifting market conditions and beliefs about the future affect the expectations of the participants. But by averaging forward market prices across each trading day in all of September 2001 for standardized forward products for each delivery location and delivery date in the Shell and Iberdrola Contracts, I was able to calculate a reasonable cost of substitute power as of September 2001 for the deliveries under those contracts for the period October 2001 forward, subject to potential adjustments to account for differences in non-price terms in the CDWR contracts. Reliance on forward market prices to derive or build up contract prices for more complex patterns of future deliveries of energy is commonplace in the electric power industry. For example, at the time Shell and Iberdrola were negotiating their long-term contracts with CDWR, each utilized reported forward prices in their assessment of the contracts' prices.[24]

Q. Have you considered that there are differences in non-price terms between many of the contracts underlying the reported forward prices and the Shell and Iberdrola Contracts?

A. I have considered this point, and accounted for it in my analysis. The forward contracts most actively traded generally specify delivery of a fixed amount of energy at a flat rate over a specified delivery period at a single location. In contrast, the Shell and Iberdrola Contracts included options which provided both the seller and buyer certain flexibility concerning delivery volumes, times or periods of delivery, and location. As explained in more detail later in my testimony, I conclude that on net the options in the Shell Contract benefited Shell more than CDWR, making my comparison of the Shell prices to forward market prices conservative. [redacted]

[24] See Prepared Direct Testimony of Gerald A. Taylor on behalf of the California Parties, Part II, Exh. No. CAL-319 at Sections III.A.2, III.B.2; Prepared Direct Testimony of Richard E. Goldberg, Ph.D. on behalf of the California Parties, Exh. No. CAL-604 at 43-44 (Goldberg Direct Testimony).

Q. Why did you choose September 2001 forward prices to compare against the Shell and Iberdrola Contracts?

A. As shown in Figure 5 below, and as further described by my colleague Dr. Goldberg,[25] forward prices in California were high and volatile in the first part of 2001 due to inadequate competition and extensive market manipulation by wholesale energy suppliers. My review of market data suggests that dysfunction persisted in the forward markets through July and into the first part of August, but that by September 2001, the forward markets had returned to competitive levels, as demonstrated by the following:

- TFS forward prices for Q1 2002 on-peak deliveries at COB came down substantially from more than $250/MWh in April 2001 to less than $50/MWh in September 2001 (see Figure 5). Similar price trends were observed for other forward products as shown in Figure 6.
- Forward market liquidity also improved by fall 2001 as indicated by lower bid-ask spreads. This is important because the willingness to contract over long horizons depends in part on participants' confidence in the ability to move in and out of their positions with other traders over time.

[25] Goldberg Direct Testimony, Exh. No. CAL-604 at 16-23.

- Market heat rates[26] implied by forward market prices for near-term power and gas were substantially lower in September 2001 trading days compared to May 2001, and largely consistent with the heat rates of gas units expected to be on the margin in California in 2001. For example, the annual average market implied heat rate as of September 2001 trading days for peak-hour (6x16) product at NP-15 was approximately 9,200 btu/kWh for 2002-2004 delivery years, which is consistent with the typical heat rates of existing gas-fired units.
- And finally, forward market prices for future deliveries remained stable around the September 2001 averages for the rest of the trading days in 2001.

Based on these observations, I determined that the dysfunction that pervaded the markets when the Shell and Iberdrola Contracts were negotiated and executed had subsided by September 2001, and therefore it was appropriate to develop post-Crisis forward market prices based on prices reported during trading days in that month.

---

[26] For a discussion of "heat rate" and "implied heat rate," see Prepared Direct Testimony of Peter S. Fox-Penner on behalf of the California Parties, Exh. No. CAL-513 at 61-63.

Figure 5
Daily TFS Forward Market Prices for Q1 2002 at COB

Figure 6
Daily TFS Forward Market Prices for Q1 2002 at NP-15 and SP-15

Q. For which products did you derive post-Crisis forward market prices?

A. For the Shell Contract, I derived post-Crisis forward market prices for on-peak (6x16) and clock-hour (7x24) energy delivered at NP-15 and SP-15. For the Iberdrola Contract, I derived post-Crisis forward market prices for clock-hour energy delivered at COB through December 2002. Because the dispatchable energy delivered under the Iberdrola Contract from January 2003 forward was more likely to be scheduled during on-peak hours, I derived post-Crisis forward market prices for on-peak deliveries at COB for the remainder of the contract term.

Q. Please describe your methodology to derive post-Crisis forward market prices for products delivered through 2005.

A. I derived post-Crisis forward market prices for on-peak deliveries by averaging the on-peak forward market prices for each relevant delivery period reported by TFS during September 2001 trading days. Separate prices were calculated for each delivery location (NP-15, SP-15 and COB) for each delivery month through 2005. I assigned monthly shapes to the quarterly and annual prices reported by TFS based on monthly shapes reported by another broker, NatSource, for the period October 2001 through September 2002.

TFS forward market prices were not available for September 2001 trading days for clock-hour or off-peak energy; only on-peak contracts were traded or recorded. I therefore developed clock-hour prices based on the relationship between on-peak and off-peak prices reported by NatSource. As shown in Figure 7, on-peak forward market prices for Q1 2002 deliveries reported by TFS and NatSource were very close to each other during trading days in September 2001. Prices for off-peak monthly products reported by Natsource in September 2001 for the delivery period October 2001 – September 2002 traded at an 18-41% discount to the corresponding on-peak prices reported by NatSource for the same period depending on delivery location (NP-15, SP-15 and COB) and month. By applying the percentage differences between off-peak and on-peak prices in the NatSource data for each delivery location to the on-peak TFS prices for the same delivery location, I calculated equivalent TFS-based off-peak forward market prices for NP-15, SP-15 and COB. I then estimated clock-hour (7x24) prices for each delivery location by taking the hour-weighted average of on-peak and off-peak prices. Figure 8 sets forth my on-peak and clock-hour post-Crisis forward market prices for deliveries through 2005.

Figure 7
Daily Forward Market On-Peak Prices Reported by TFS and NatSource for Q1 2002 Delivery Period

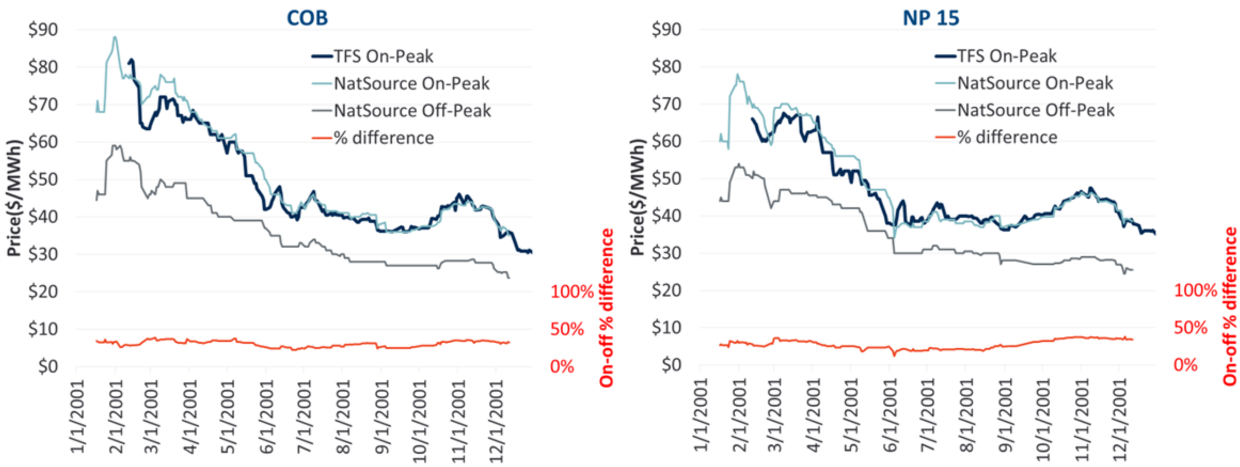
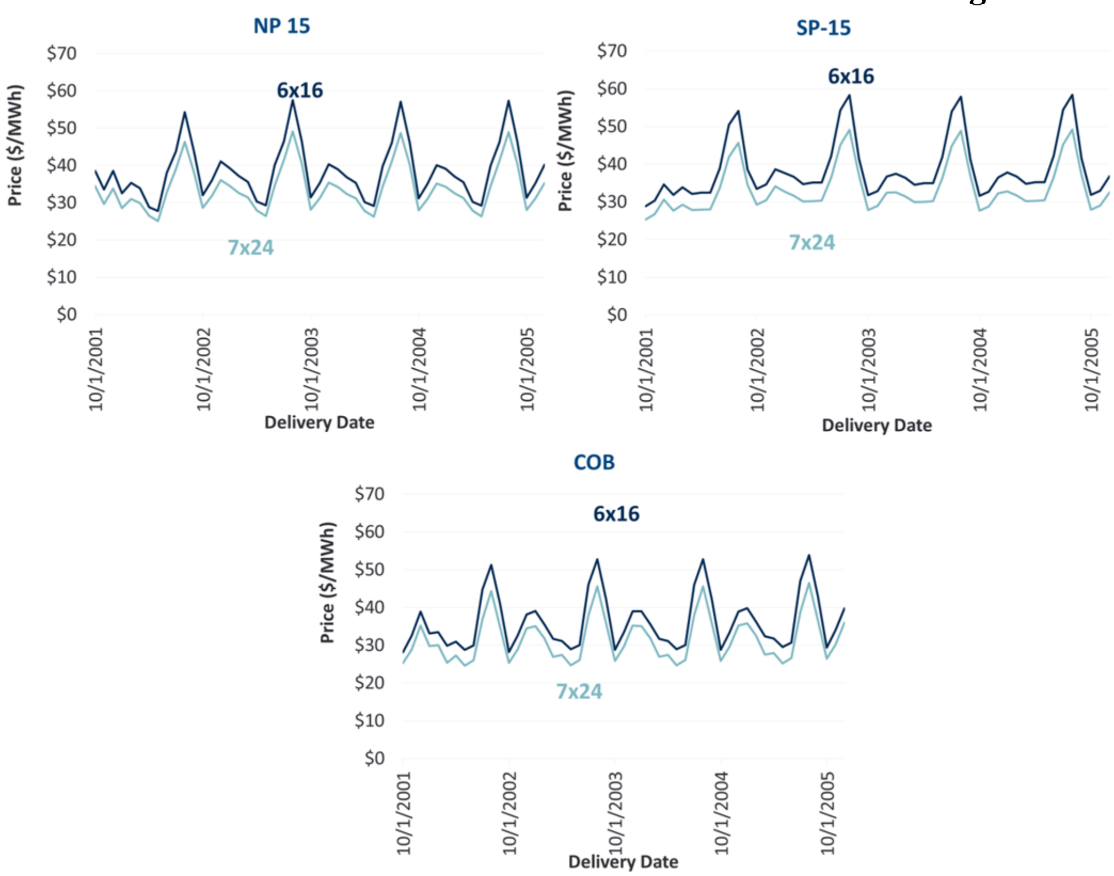


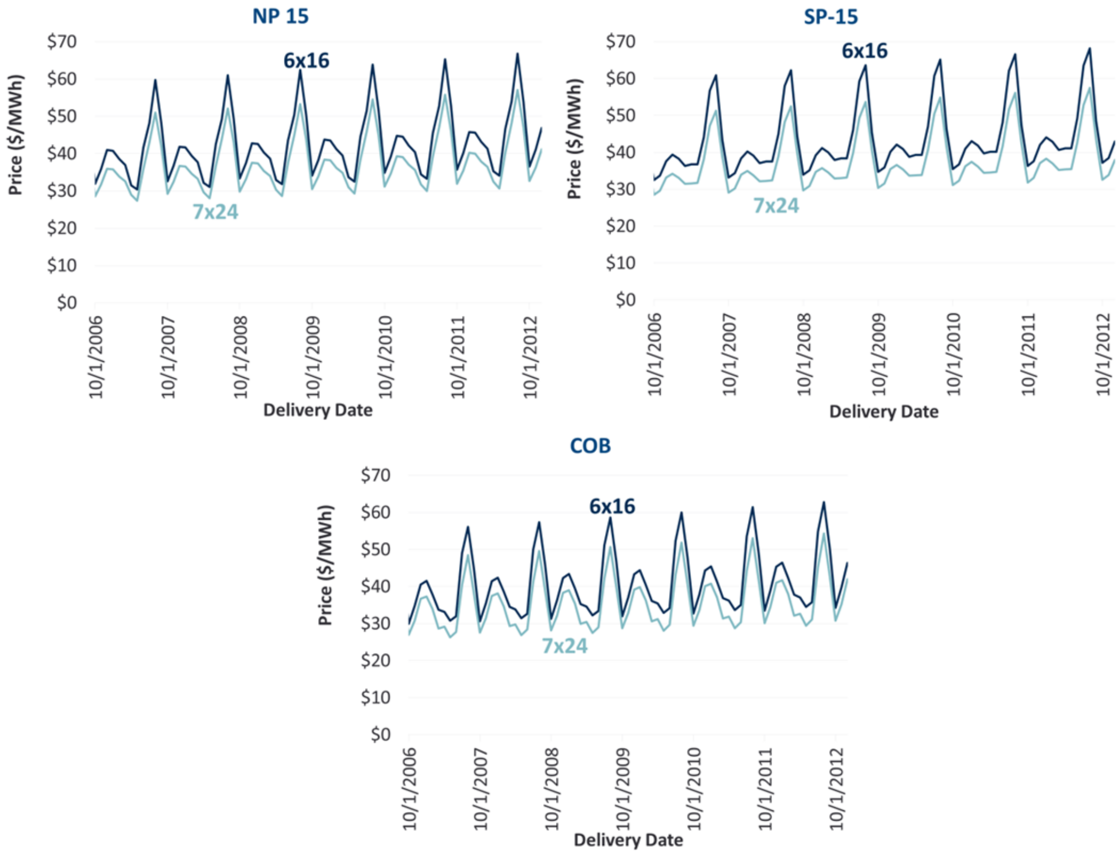
Figure 8
Post-Crisis Forward Market Prices For Deliveries Through 2005



Q. How did you derive the post-Crisis forward market prices for later delivery periods in the Shell and Iberdrola Contracts (2006-2012)?

A. In both TFS and NatSource data, forward prices as of September 2001 were reported through 2005 deliveries only. In order to calculate market prices for each month from 2006 through 2012, I escalated the prior year's monthly post-Crisis forward market prices for the same month by the growth rate implied by natural gas price forecasts as of September 2001 at Henry Hub. This approach is based on the observation that gas-fired generation units are typically on the margin in California energy markets, and thus gas price is a major driver of California's energy prices. My approach also implies that market heat rates remain constant after 2005 at their then-prevailing levels. Since gas prices were projected to increase from 2005 onwards as of September 2001, the projected forward market energy prices increase comparably beyond 2005. Figure 9 sets forth my on-peak and clock-hour post-Crisis forward market prices for 2006-2012 deliveries.

Figure 9
Post-Crisis Forward Market Prices For Deliveries During 2006 - 2012



Q. **Please describe how you estimated the payments CDWR would have made under the post-Crisis forward market prices.**

A. This is a very simple step of multiplying the actual monthly delivery volumes by the monthly prices I just described. That is, for each month of contract deliveries, I multiplied the actual volumes delivered under the Shell and Iberdrola Contracts for each product (in MWh) by the reported or estimated post-Crisis forward market price for that product, starting in October 2001. I excluded from my analysis volumes delivered (and associated contract payments) prior to the end of August 2001, when the markets were still dysfunctional, as well as volumes delivered in September 2001, the month I used to establish post-Crisis forward market prices.

Q. What would CDWR have paid under the post-Crisis forward market prices for the energy volumes delivered under the Shell Contract from October 2001 through the end of the contract term?

A. $1.40 billion, at an average all-in price of $40.85/MWh (nominal $s).

Q. What would CDWR have paid under the post-Crisis forward market prices for the energy volumes delivered under the Iberdrola Contract from October 2001 through the end of the contract term?

A. $440 million, at an average all-in price of $38.89/MWh (nominal $s).

Q. How do the actual annual average contract prices compare to the post-Crisis forward market prices?

A. Actual prices in the Shell and Iberdrola Contracts exceeded the post-Crisis forward market prices for all years. The Shell Contract prices exceeded post-Crisis forward market prices by more than $100/MWh for the initial few years, with a decreasing difference in later years (see Figure 10 and Table 2). The Iberdrola Contract prices exceeded post-Crisis forward market prices by roughly $30/MWh in the initial years, and the difference increased to more than $50/MWh in later years (see Figure 11 and Table 3).

Figure 10
Actual Shell Contract Prices vs. Post-Crisis Forward Market Prices ($/MWh)

Table 2
Actual Shell Contract Prices vs. Post-Crisis Forward Market Prices ($/MWh)

Year	Volume	Actual Price	Forwards-Based Price
	(MWh)	*($/MWh)*	*($/MWh)*
2001	166,400	$185	$31
2002	1,450,900	$161	$38
2003	2,600,482	$177	$40
2004	3,555,554	$79	$39
2005	3,894,482	$78	$39
2006	3,703,762	$71	$39
2007	3,901,024	$71	$41
2008	3,916,624	$84	$42
2009	3,907,616	$51	$43
2010	3,215,952	$58	$43
2011	2,614,032	$55	$44
2012	1,237,774	$45	$41

Figure 11
Actual Iberdrola Contract Prices vs. Post-Crisis Forward Market Prices
($/MWh)

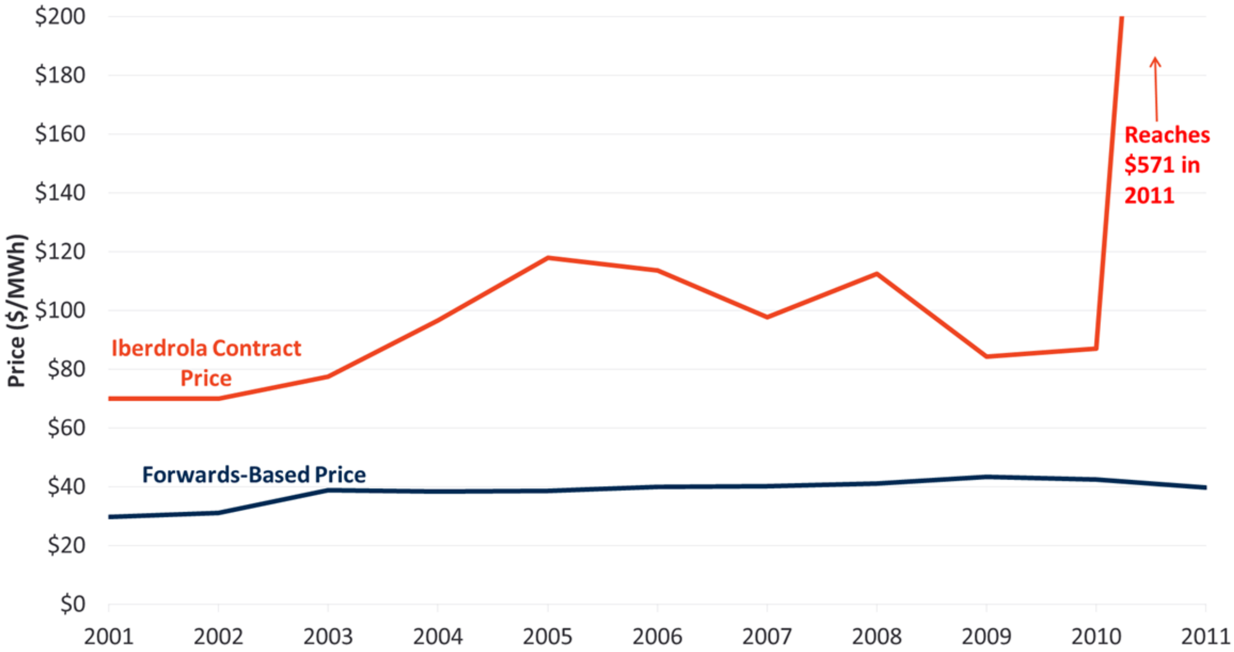


Table 3
Actual Iberdrola Contract Prices vs. Post-Crisis Forward Market Prices
($/MWh)

Year	Volume	Actual Price	Forwards-Based Price
	(MWh)	*($/MWh)*	*($/MWh)*
2001	331,000	$70	$30
2002	1,532,180	$70	$31
2003	1,031,004	$77	$39
2004	1,005,695	$96	$38
2005	1,110,580	$118	$39
2006	963,279	$114	$40
2007	1,456,195	$98	$40
2008	1,299,741	$113	$41
2009	1,260,083	$84	$43
2010	1,253,622	$87	$42
2011	60,644	$571	$40

2. Quantification of the "Down the Line" Economic Burden Caused by the Shell and Iberdrola Contracts

Q. Based on your analysis, what is the "down the line" economic burden on California consumers caused by the Shell and Iberdrola Contracts?

A. The Shell Contract caused a down the line burden of $1.37 billion compared to payments for the same energy deliveries under post-Crisis forward market prices. ($2.762 billion in actual payments - $1.396 billion in forwards-based payments = $1.37 billion). This is depicted in Figure 12. The down the line burden caused by the Iberdrola Contracts totals $601 million. ($1.085 billion in actual payments - $485 million in forwards-based payments = $601 million). This is depicted in Figure 13. While the overall Iberdrola burden is smaller than the overall Shell burden, the delta between average contract prices and average post-Crisis forward market prices was actually higher for the Iberdrola Contract ($53.14/MWh) than for the Shell Contract ($40.01/MWh). All of these figures are expressed in nominal dollars, [redacted] This "down the line" burden is calculated from October 2001 onward, and does not include energy deliveries or payments under the contracts from May – September 30, 2001.

Figure 12
Actual Shell Contract Payments vs. Post-Crisis Forward Market-Based Payments (Nominal $s)

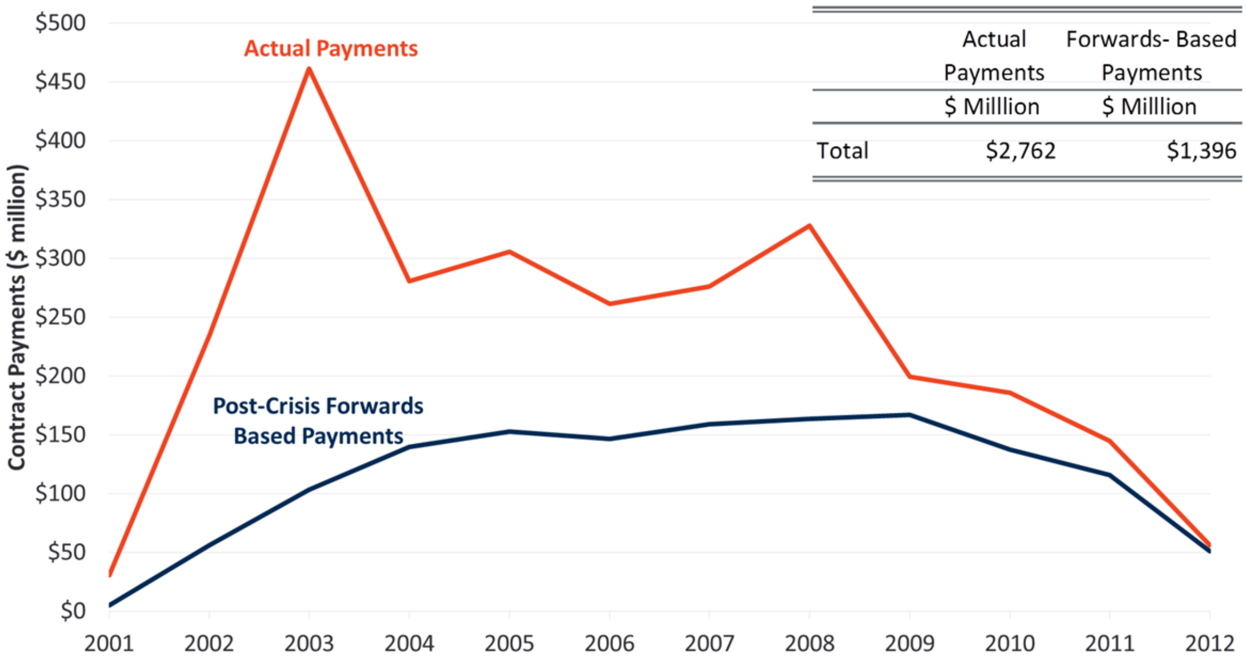
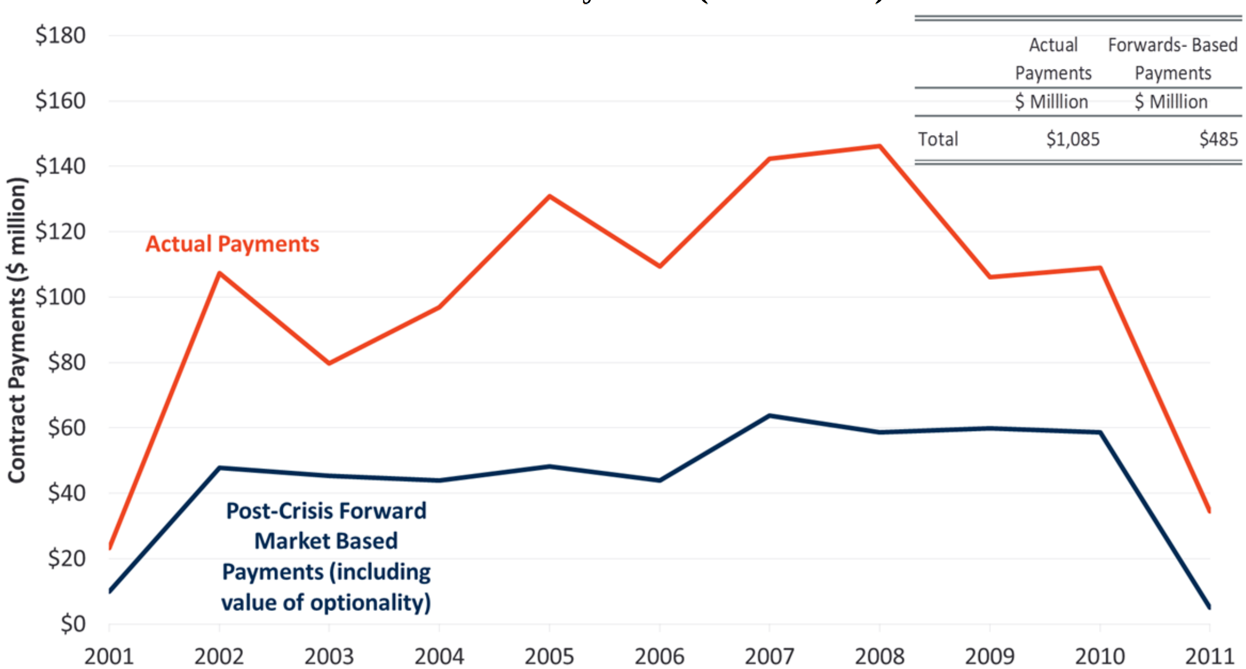


Figure 13
Actual Iberdrola Contract Payments vs. Post-Crisis Forward Market-Based Payments (Nominal $s)



Q. Have you also calculated the economic burden with interest to May 2015?

A. Yes, with FERC quarterly interest rates applied through May 2015, the down the line economic burden increases to $2.14 billion for the Shell Contract and $875 million for the Iberdrola Contract.

Q. Did you make any adjustments to the estimated payments under the post-Crisis forward market prices to account for the value of non-price terms in the Shell Contract?

A. Based on my review of the Shell Contract, as well as Shell's own internal analyses, I concluded that on net the non-price terms in the contract benefitted Shell more than CDWR. I did not reduce payments under the post-Crisis forward market prices to account for these benefits to Shell.

Q. What were the key non-price terms in the Shell Contract?

A. The key non-price terms in the Shell Contract, which are summarized in Exh. No. CAL-636, are related to volume and delivery location flexibility. After 2006, CDWR had the option to reduce volumes by 25 MW per quarter for the 7x24 product delivered under the contract. Starting in 2002, CDWR also had the option to schedule dispatch of each of the five Wildflower Peaking Units up to 500 hours each calendar year through 2005. Shell, in turn, had much greater volume optionality than CDWR. Shell could reduce peak-hour and clock-hour volumes and increase peak-hour volumes by 10% annually. In addition, Shell had the option to increase peak-hour volumes by 175 MW from July 2003 through the remainder of the contract term, and another 175 MW from July 2004 onward, for a total increase of 350 MW. The contract also afforded Shell significant flexibility on delivery location. With the exception of 2001, Shell had the option to deliver 75% of the contracted energy (base and additional quantities) to its choice of any of the three designated delivery locations (NP-15, SP-15, or ZP-26).

Q. Did Shell quantify the value of these non-price terms?

A. Yes. In an analysis dated May 10, 2001, Shell estimated its ability to adjust volumes up or down by 10% to be worth roughly $24 million to Shell over the life of the contract, and the combined present value of the option value of adding the additional energy volumes in 2003 and 2004 to be $89 million.[27] Shell estimated the value of its delivery location flexibility as approximately $40 million.[28] In contrast, Shell estimated the value of CDWR's ability to reduce volumes by 25 MW starting in 2007 as $11 million.[29] All but the $11 million of these benefits would accrue to Shell, not CDWR.

---

[27] Exh. No. CAL-647i; Exh. No. CAL-647ii (see "Summary - CDWR" tab).

[28] Exh. No. CAL-648.

[29] Exh. No. CAL-647ii (see "Summary - CDWR" tab).

Q. How did delivery location flexibility add value to Shell?

A. It allowed Shell to deliver energy to the location with the lowest price. Since Shell could supply the contract power from any source including market purchases, this meant that Shell could lower its costs, and therefore increase its profits, through buying power from the market at the lowest-price location and delivering to CDWR at that low-price location while obtaining the same price under the contract.

Q. Have you also analyzed the key non-price terms in the Iberdrola Contract?

A. Yes. The Iberdrola Contract also provided volume and delivery location flexibility as summarized in Exh. No. CAL-637. Starting in January 2003, CDWR could reduce monthly schedule volumes and/or make daily or hourly adjustments to delivery volumes. This dispatch flexibility for CDWR, however, was subject to various restrictions as well as additional cycling, start-up, and fuel costs.[30] The contract also afforded Iberdrola substantial flexibility. Iberdrola could reduce up to 12% of delivery volumes annually due to forced outages and scheduled maintenance, and up

[30] For example, Iberdrola was not required to accept schedules that required Klamath Falls to operate below the Minimum Generation Level, or in a manner inconsistent with the ramp rate, or in a manner that conflicts with the schedules of other purchasers of Klamath Falls' output. Schedule changes were also subject to cycling costs and increased costs resulting from an increased heat rate (see Exh. No. CAL-41, Articles 6.2.2-6.2.4).

to 3% of delivery volumes could be curtailed for any reason except during the period June 15 through October 15. This meant that Iberdrola could potentially reduce or cut deliveries during a portion of the most valuable 15% of hours in a given year (except for hours during forced outages that would have been outside Iberdrola's control). Like the Shell Contract, the Iberdrola Contract also provided delivery location flexibility. Iberdrola could deliver to COB at any time, 50 MW to NP-15 on a monthly scheduled basis, and another 50 MW on a daily pre-scheduled basis.

Q. Did Iberdrola quantify the value of these non-price terms?

[redacted]

---

[31] Exh. No. CAL-649i (PROTECTED); Exh. No. CAL-649ii (PROTECTED) (see "Jun 28, 2002 Old Contract" tab).

[32] Exh. No. CAL-650 (PROTECTED).

[redacted]

Q. Have you tested your "down the line" burden estimate based on September 2001 forward market prices against prices from later trading dates in 2001?

A. Yes. I conducted additional analyses using average forward market prices in each month during the period October – December 2001 to assess the sensitivity of the results to choosing different trading dates for "post-Crisis" prices. For consistency in the monthly comparisons, I limited my analysis to actual payments and delivery volumes for the period starting January 2002. The difference between actual payments and payments under the average forward market prices in October, November, and December 2001 for delivery volumes from January 2002 through the end of contract terms

[33] Exh. No. CAL-649ii (PROTECTED) (see "Jun 28, 2002 Old Contract" tab).

ranged from $1.96 – $2.13 billion for the Shell Contract and $801 – $877 million for the Iberdrola Contract.

If September 2001 forward market prices are applied to those same deliveries, the price differential is $2.09 billion for the Shell Contract and $849 million for the Iberdrola Contract. This sensitivity analysis confirmed that using forward market prices from the October – December 2001 period would result in similar burden estimates compared to those based on September 2001 forward market prices.

C. Comparison to Fundamentals-Based Prices

Q. Dr. Celebi, have you also calculated prices for the products delivered under the Shell and Iberdrola Contracts based on expected market fundamentals?

A. Yes, to further corroborate my burden findings based on post-Crisis forward market prices, I conducted a separate analysis to estimate prices expected as of the Shell and Iberdrola Contract execution dates (May 25 and July 6, 2001) based on then-existing market fundamentals in the underlying cost elements of producing electric power. I then compared payments under the Shell and Iberdrola Contract prices to payments under the fundamentals-based prices for the entire contract terms.

Q. What were the results of this analysis?

A. I determined that the Shell and Iberdrola Contract prices significantly exceeded any reasonable price that could have been expected by a good faith seller in an arms-length transaction from an uncoerced buyer based on market fundamentals at the time the contracts were executed.

Q. Please describe the methodology you used to determine fundamentals-based prices.

A. I employed a two-step process. First, for the near-term years (2001 – 2004), I utilized market simulation software to estimate marginal prices based on expected conditions of supply and demand as of the contract execution dates. Then, for the later years (2005 – 2012), I developed prices consistent with long-run equilibrium conditions by projecting the costs to build and operate a new gas-fired combined-cycle plant as of the contract execution dates, and translating those costs to a $/MWh figure for each product delivered under the contracts.

Q. Why did you use a different approach to estimate prices in the near term than you used for the later years?

A. In a functioning competitive market, expected energy prices in the near-term should reflect the short-run marginal costs of generation, i.e., the marginal production cost of available, existing units on the margin.[34] My estimate of prices for the initial years based on market simulations provides recovery of these short-run marginal costs for existing units and newly announced units. However, applying these same short-run marginal cost estimates to the later years of the Shell and Iberdrola Contract terms would not necessarily provide the efficient price signals required to attract new generation to meet load growth. In the long-run, and under equilibrium conditions of having the amount of capacity in place to balance customer needs for reliability against the costs of additional entry, competitive energy prices should be high enough to provide recovery of capital and operating costs (or all-in costs) of new generation units. I refer to these all-in costs as long-run marginal cost (LRMC). The expected period of time to reach long-run equilibrium depends on how quickly new generation units can be built to meet the increased need for generation. Here, I assumed transition to long-run equilibrium conditions would occur in 2005 because in the early 2000s, it took approximately four years to develop a new gas-fired combined-cycle generation plant in California.[35] Thus, starting in

[34] In economics, the "short run" is defined as the timeframe within which the available supply is fixed, i.e. new entry cannot occur.

[35] This is based on a sample of six California combined-cycle plants that came online between 2003 and 2006. Sources include: http://www.energy.ca.gov/sitingcases/all_projects.html#approved, and various CPUC Siting Cases (for example: http://www.energy.ca.gov/sitingcases/elkhills/index.html).

(Continued …)

2005, my estimated prices are based on the projected cost to build and operate a new gas-fired combined-cycle plant.

1. Fundamentals-Based Prices in the Near Term (2001-2004)

Q. How did you calculate fundamentals-based prices for the period 2001-2004?

A. I used a market simulation software package developed by Cambridge Energy Solutions (CES) known as DAYZER (Day-Ahead Locational Market Clearing Prices Analyzer) [36] to replicate system conditions and market operations in the Western Electricity Coordinating Council (WECC) wholesale power markets, including the California market, as they were known as of the execution dates for the Shell and Iberdrola Contracts, and to estimate marginal Day Ahead energy prices as of those dates through the end of 2004 for the products specified in the Shell and Iberdrola Contracts.

Q. Please explain DAYZER and how it works.

A. DAYZER is a chronological hourly simulation model that optimizes the mix of output from generation resources (subject to physical constraints on

---

In Annual Energy Outlook 2001, EIA assumed a 3-year lead time for a generic gas CC in the United States. See Energy Information Administration, "Assumptions to the Annual Energy Outlook 2001," Table 43, December 2000.

In CEC's June 2003 study, a 3-year lead time was assumed for a new gas CC in California. See California Energy Commission, "Comparative Cost Of California Central Station Electricity Generation Technologies," Appendix C, June 5, 2003.

[36] More information about the DAYZER model is available in Exh. No. CAL-643 and at http://www.ces-us.com/product-dayzer.asp.

generation operations and transmission flows) to serve load in a system such as the WECC, and calculates hourly marginal cost of energy at each pricing location.[37] In short, DAYZER mimics the dispatch procedures adopted by independent system operators (ISOs), for example the California ISO, and approximates the calculations made by the ISOs in solving security-constrained, least-cost unit commitment and dispatch in the day-ahead markets. The DAYZER package I used simulates the dispatch of the entire WECC system, and accurately models the security, reliability, economic and engineering constraints on generating units and transmission system components in the system based on input assumptions and data. In this instance, I used DAYZER to replicate WECC system conditions as they were known as of the execution dates of the Shell and Iberdrola Contracts based on input assumptions concerning then-reigning market fundamentals. The marginal costs resulting from these simulated operations are the short-run marginal cost prices that I would expect in a competitive market for energy. And since forward prices are derived from expected Spot Market prices, the DAYZER simulations can be used as

[37] The optimization involves security-constrained unit commitment and economic dispatch of generation units. It determines the optimal commitment and dispatch of generation sources, taking into consideration constraints to assure that the transmission flows are physically feasible both with and without contingencies (i.e., outages) at transmission elements (lines and transformers).

proxies for those forwards, had traders expected a competitive market outcome in the future.

Q. What were the key market fundamentals in the WECC at the time the Shell and Iberdrola Contracts were executed?

A. As of 2001 the key fundamentals affecting future energy prices in the Western markets were: (1) natural gas forward market prices; (2) hydroelectric conditions; (3) generation capacity; (4) load growth; (5) generation outages; (6) environmental constraints; and (7) transmission constraints.

Q. What assumptions did you make concerning these market fundamentals in estimating near term prices?

A. Exh. No. CAL-643 provides a detailed description of all input assumptions and source data for my DAYZER simulations, as well as a more detailed description of the DAYZER model and how it works. I summarize the key assumptions below, and also provide a brief description of why each fundamental was important to Western forward energy prices in 2001.

Natural gas forward market prices: Natural gas prices are a major driver of power prices because gas generators tend to be the marginal units providing energy in California, and dispatch costs of gas units are directly proportional to the daily market cost of gas burned as fuel. For my future natural gas price assumptions, I used forward market prices reported by major brokers.

Hydroelectric conditions: Future availability of energy from hydro generation units (with their low variable production costs) determine how much additional energy needs to be provided by more expensive fossil-fuel generators to meet load. Hydro conditions in California and the Northwest United States were showing less than normal snow pack and reservoir levels as of the spring of 2001, and hydroelectric generation for the rest of 2001 was expected to be lower than the historically normal levels.[38] Therefore, I assumed the hydro output for the rest of 2001 to reflect the dry hydro conditions in 1994 (the lowest hydroelectric generation year in the WECC system during the period 1994 – 2000). For 2002 – 2004, I developed scenarios for base, dry and wet hydro conditions based on historical hydro generation information, and ran DAYZER simulations based on each scenario.

Generation capacity: Future additions and retirements of generation units influence energy prices by changing the shape of the generation supply curve used to determine energy market-clearing prices. The basis for my assumptions for net new generation capacity expected in California from the contract execution dates through year end 2004 are

[38] "CAISO Summer 2001 Assessment," March 22, 2001, page 9.

detailed in Exh. No. CAL-643. I have concluded that total generation capacity in California was expected to increase from 64 GW in 2001 to 76 GW by 2004.

Load growth: Future load conditions affect which generation units need to be dispatched, and higher load tends to increase the market price of power, especially in the short run. For my analysis, I assumed that as of early 2001 California peak load was expected to grow from 56 GW in 2001 to 60 GW in 2004 (or slightly less than 1 GW per year of growth).

Generation outages: Expected outages at generation units affect how much total generation will be available in the future to meet load, and thus tend to increase power prices. Some of the Qualified Facility (QF) capacity in California was unavailable due to economic factors in 2001, and the ISO was expecting in March 2001 that approximately 3 GW of QF capacity would continue to be unavailable in summer of 2001. I conservatively assumed that 3 GW of QF capacity in California remained unavailable for all years during the period 2001 – 2004.

Environmental constraints: Certain of the generation units in California (such as the ones located in the South Coast Air Quality Management District) were subject to fees for NOx emissions in 2001. These fees have the effect of increasing the marginal cost of generators with NOx emissions. I assumed that all California units would face NOx emission fees of $5/lb ($10,000/ton) during the period May 2001 through December 2004 based on the mid-point of $0 - 10/lb range of NOx fees in 2001 that were faced by a subset of generation units in California. My assumption for NOx emissions costs for May 2001 through 2004 is consistent with the assumption used by Dr. Tabors for the similar period in testifying on behalf of Dynegy, a respondent in this proceeding in 2002.[39]

Transmission constraints: Transmission system limitations influence market prices by dispatching otherwise uneconomic generating resources to maintain the system's overall energy balance. These limitations can cause transmission system congestion, which can lead to price separation between different pricing nodes on the transmission system. For my analysis, I developed the WECC transmission system for 2001 – 2004 by starting with the 2005 default power flow data from DAYZER database, and adjusting it to reflect conditions for each year from 2001 through 2004 based on reported transmission interface and line data for those years, as described in Exh. No. CAL-643.

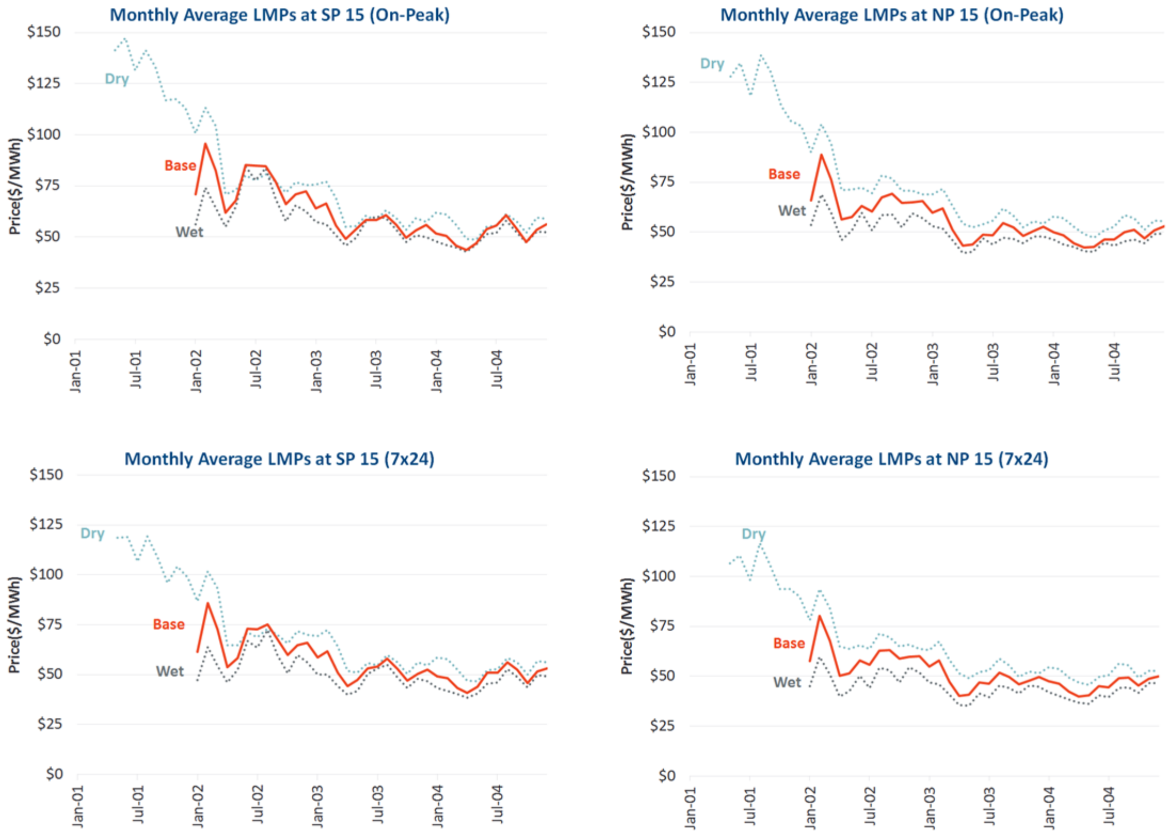
---

[39] Exh. No. DYN-34 at 5.

Q. Based on your DAYZER analysis, what were the fundamentals-based prices for products delivered under the Shell Contract for the period 2001-2004?

A. I estimate monthly on-peak prices at NP-15 and SP-15 in the range of $103 – 147/MWh for the rest of 2001, and $40 – 113/MWh for years 2002 – 2004. I estimate monthly clock-hour prices at the same locations in the range of $90 – 119/MWh in 2001, and $35 – 102/MWh for years 2002 – 2004. All estimates include a $5/MWh adder described later in my testimony. The price ranges result from the different hydro condition assumptions explained previously in my testimony. Figure 14 demonstrates the prices under each of my three hydro scenarios (base, dry, and wet). The higher prices in 2001 are driven primarily by higher natural gas prices.

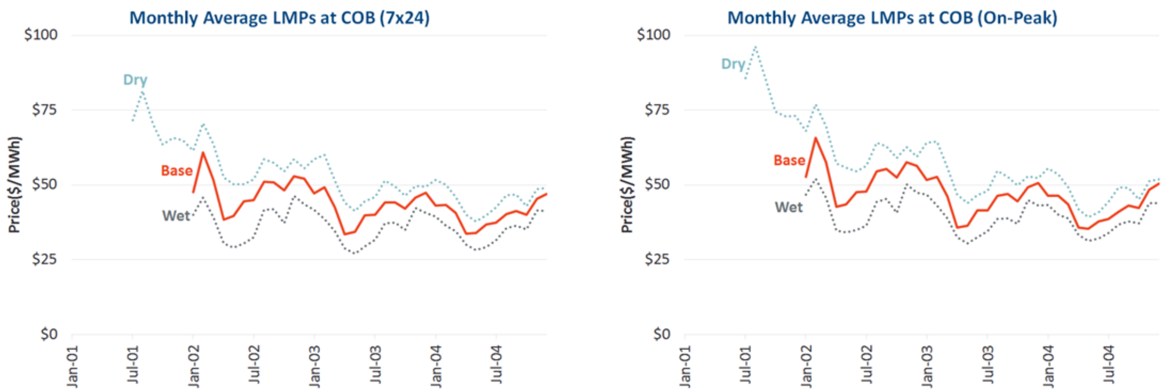
Figure 14
Estimated Fundamentals-Based NP-15 and SP-15 Prices as of Shell Contract Execution ($/MWh)



Q. What were the estimated fundamentals-based prices for products delivered under the Iberdrola Contract for the period 2001-2004?

A. I estimate monthly on-peak prices at COB in the range of $73 – 96/MWh for the rest of 2001, and $30 – 77/MWh for years 2002 – 2004. I estimate monthly clock-hour prices at the same location in the range of $64 – 82/MWh for the rest of 2001, and $27 – 71/MWh in years 2002 – 2004. As with the Shell Contract, all estimates include a $5/MWh adder. Figure 15 demonstrates the prices under each of my three hydro scenarios (base, dry and wet). I explain how my DAYZER-simulated prices compare to the Shell and Iberdrola Contract prices later in my testimony, after I introduce fundamentals-based prices for the contracts' later years.

Figure 15
Estimated Fundamentals-Based COB Prices as of Iberdrola Contract Execution ($/MWh)



Q. Have you tested the DAYZER model against actual market prices in a properly functioning market?

A. Yes. I tested DAYZER-simulated prices for 2005 against actual 2005 prices in California (daily average Day Ahead on-peak and off-peak prices for NP-15 and SP-15 as reported by Intercontinental Exchange (ICE)) to show that DAYZER was able to approximate actual market prices in a functioning market. For this simulation, I used actual natural gas prices, actual hydro conditions and actual outages at California generation and transmission facilities in 2005.

Q. What were the results of your analysis?

A. The simulated prices are very close to the actual prices, as detailed in Table 4. Across all hours in 2005, annual average DAYZER prices and actual prices were approximately the same.

Table 4
Average Prices in DAYZER Backcast vs. 2005 Actual Prices ($/MWh)

	NP 15			SP 15		
	Peak	Off-Peak	All Hours	Peak	Off-Peak	All Hours
DAYZER Backcast	$66.79	$57.07	$62.61	$69.26	$57.20	$64.13
2005 Actual	$72.48	$53.34	$64.61	$73.00	$53.13	$64.83

Figure 16 and Figure 17 further demonstrate the accuracy of the DAYZER model by showing the close relationship between simulated and actual prices on a daily basis throughout 2005.

Figure 16
Simulated vs. Actual SP-15 and NP-15 On-Peak Prices ($/MWh)

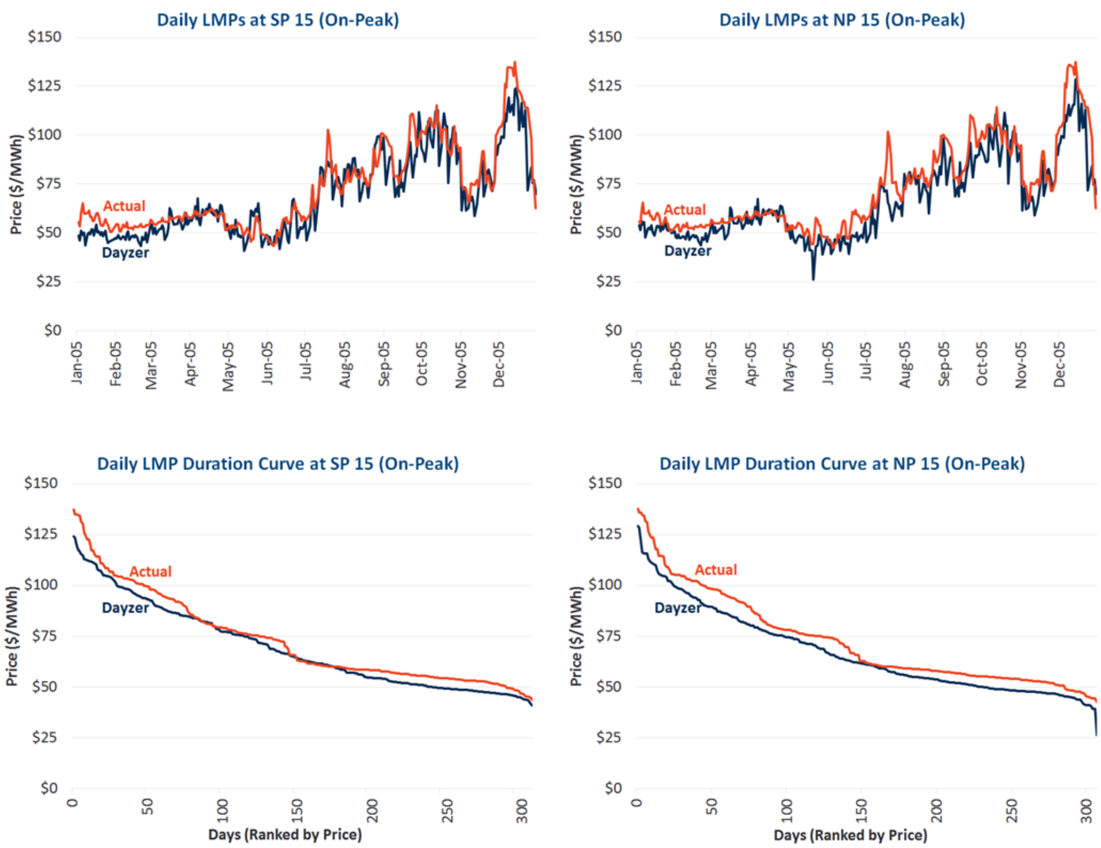
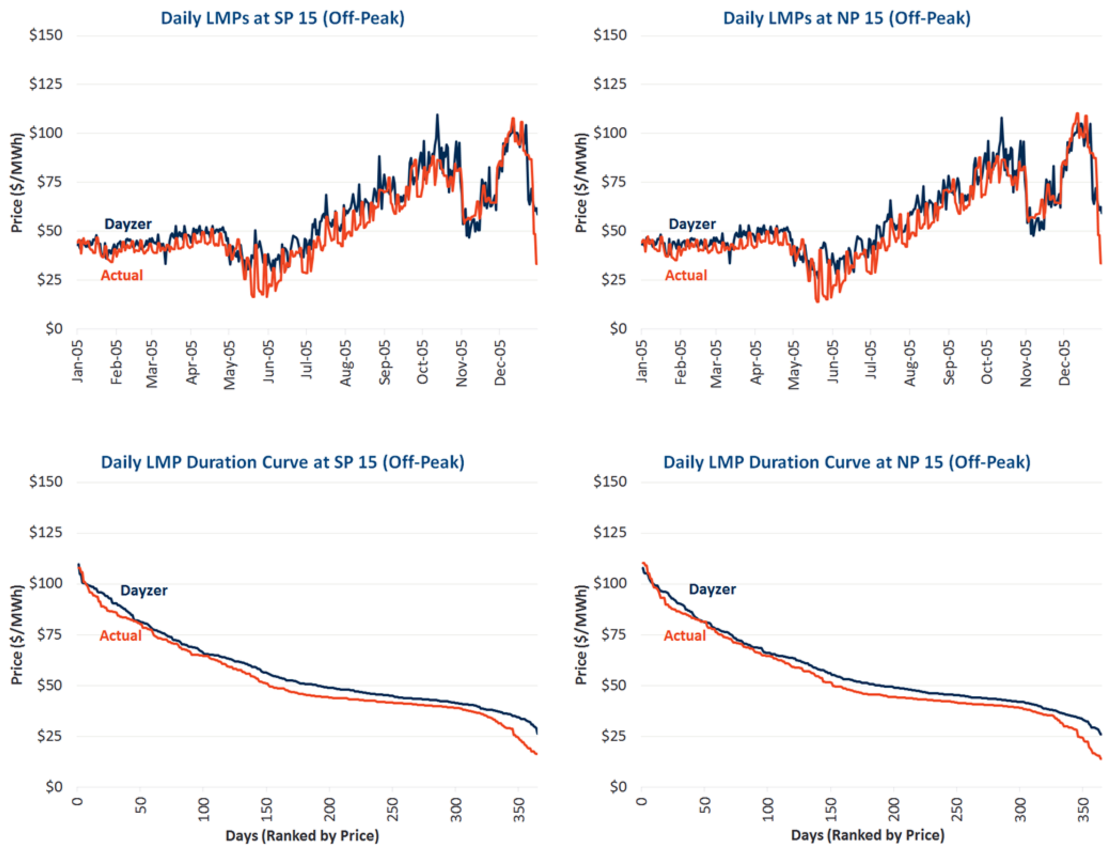


Figure 17
Simulated vs. Actual SP-15 and NP-15 Off-Peak Prices ($/MWh)



Q. Is your market simulation approach an accepted method of estimating energy prices?

A. Yes. Market simulations are routinely used to forecast future power prices as a function of expected market fundamentals and policy drivers by traders, electric utilities and analysts in evaluating economics of contracts and generation plants, economic benefits of new transmission, and resource planning studies among others. Indeed, Dr. Tabors, testifying in this proceeding in 2002 on behalf of Dynegy, used a similar simulation model (GE-MAPS) of the Western electric system to estimate future energy prices. He used information available on projected market fundamentals as of the execution date of Dynegy's long-term contract with CDWR (March 2, 2001).[40] Dr. Tabors simulated SP-15 prices for the period 2002 - 2004.[41] I also simulated SP-15 forward market prices based on March 2, 2001 market conditions with DAYZER, and my results were similar to Dr. Tabors' estimates. As shown in Figure 18, for the period 2002 - 2004, my simulated all-hour prices at SP-15 were on average \$55.20/MWh compared to Dr. Tabors' estimate of \$53.10/MWh, and my simulated on-peak prices at SP-15 were on average \$61.30/MWh compared to Dr. Tabors' estimate of 60.50/MWh. This comparison to Dr. Tabors' price projections further validates my DAYZER results.

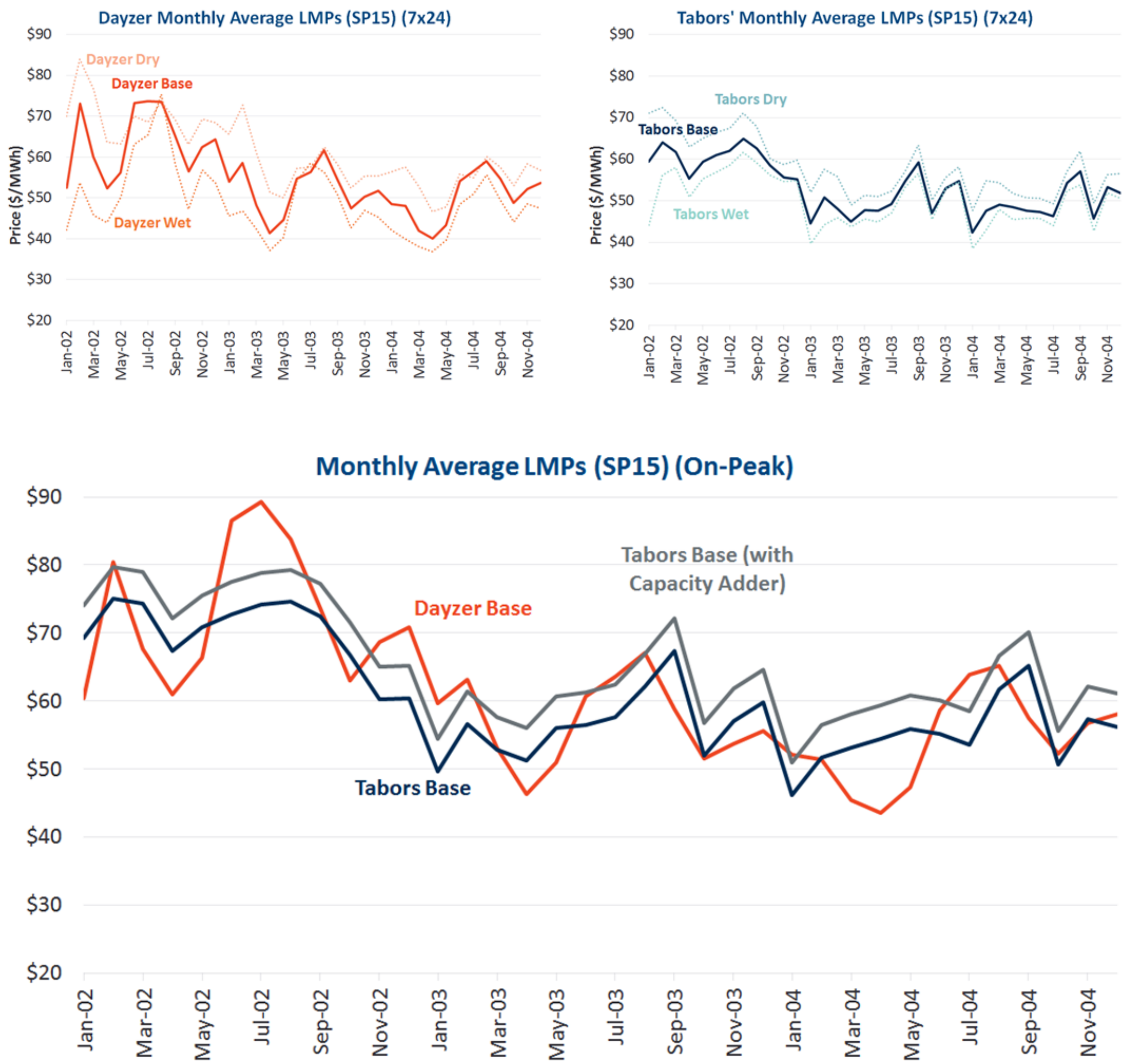
Dr. Tabors also implemented a capacity adder of approximately \$5/MWh to his on-peak simulated prices. With that adder, Dr. Tabors' estimate of average on-peak SP-15 prices during the period 2002 - 2004 increases to \$65.29/MWh, approximately \$4/MWh higher than my estimate for on-peak prices.

---

[40] Prepared Direct Testimony of Richard D. Tabors on Behalf of Dynegy Power Marketing, Inc., Exh. No. DYN-24 at 4.

[41] Exh. No. DYN-35 at 1, and workpaper "SP15 Prices All MAPS Scenarios.xls".

Figure 18
Projected Fundamentals-Based SP-15 Prices as of March 2001 ($/MWh)



Q. **Have you made any adjustments to your DAYZER-simulated prices for the period 2001-2004?**

A. Yes. Even though my DAYZER backcasting to 2005 produced prices consistent with actual average prices, I implemented a $5/MWh adder in all hours of my DAYZER-simulated prices to build in a cushion, or conservative margin for error, thereby potentially overstating my estimates of fundamentals-based pricing in favor of Shell and Iberdrola.

Q. Would your DAYZER-simulated prices allow for recovery of the all-in costs of a hypothetical new gas CC that came online in 2001?

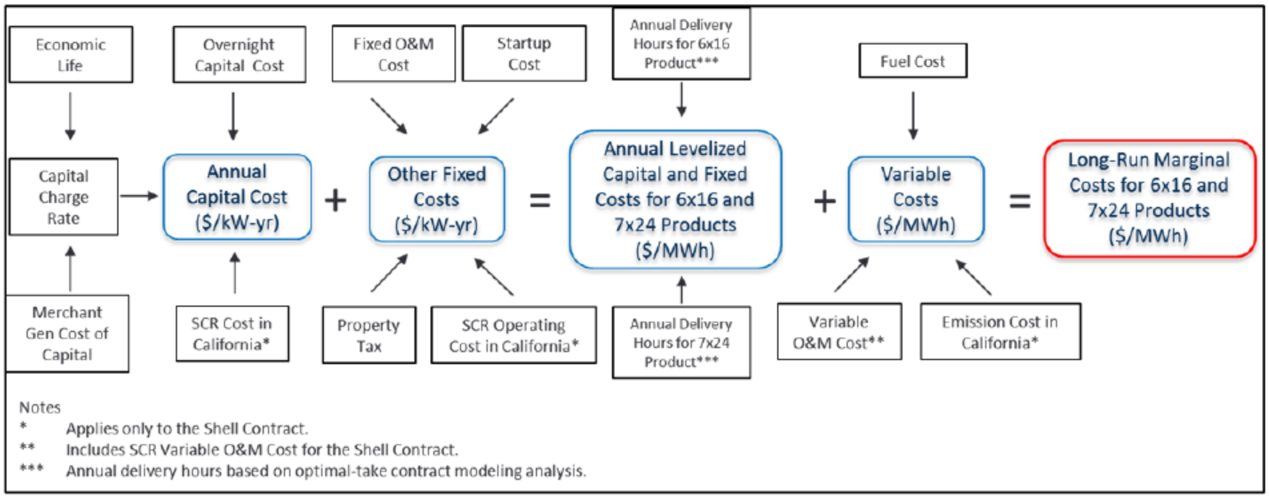
A. Yes. My DAYZER-simulated prices were approximately the same on average as the projected all-in costs of a new gas CC that came online during the period 2001 through 2004, levelized to an annual $/MWh figure. I will explain this in more detail later in my testimony after I introduce my LRMC analysis and results.

2. Fundamentals-Based Prices for the Later Years (2005-2012)

Q. You previously explained that you used an approach other than DAYZER market simulations for the later years in the Shell and Iberdrola Contracts. How did you estimate fundamentals-based prices for the period 2005-2012?

A. I calculated fundamentals-based prices for the years 2005 - 2012 consistent with long-run equilibrium conditions. Specifically, I estimated prices based on the expected cost of building and operating a new generation plant, or long-run marginal cost (LRMC). As I illustrate in Figure 19 and explain below, I estimated LRMC for each of the 6x16 (peak-hour) and 7x24 (clock-hour) products in the Shell and Iberdrola Contracts as the sum of levelized capital and fixed charges, and variable costs of operating a new generation plant. Further details on my approach are provided in Exh. No. CAL-646.

Figure 19
LRMC Estimation Methodology



Q. What type of generation plant did you use in your estimates?

A. I estimated capital and operating costs for a new gas-fired combined-cycle plant (gas CC) because a gas CC, as opposed to a simple-cycle gas turbine (gas CT), would provide the products delivered under the Shell and Iberdrola Contracts at the lowest cost. A gas CT would be better suited to provide the lowest costs only during the hours with the highest load conditions.

Q. What were your capital costs assumptions for a new gas CC plant?

A. I calculated capital costs based on data in the Energy Information Administration (EIA) Annual Energy Outlook 2001 (AEO2001) study, adjusted by a regional multiplier depending on the location of the plant.

For the Shell Contract, I assumed the plant would be located in California, with capital costs of $722/kW (in 2001 $s). I also included for the Shell Contract the cost of installing a Selective Catalytic Reduction (SCR) to control NOx emissions, as required for new plants in California, based on the California Energy Commission's (CEC) estimates. For the Iberdrola Contract, I assumed the plant would be located in Oregon (since COB was the main delivery point under the contract), with capital costs of $672/kW (in 2001 $s).

Q. How do your capital costs assumptions compare to actual reported capital costs for the relevant time period?

A. My assumed capital costs generally exceed the actual reported capital costs of gas CCs built in the WECC during the period 2001 - 2005. They also generally exceed the cost estimates in other published economic studies conducted in the 2001 - 2003 period. Table 5 displays these comparisons.

Table 5
Comparison of Estimates for Capital Cost of a New Gas CC[42]

Shell (2001 $/kW)	**Iberdrola** (2001 $/kW)	**Actual Units** (2001 $/kW)	**Other Studies** (2001 $/kW)
722	672	425-749	540-617

Q. What is your estimate of the projected annual capital costs for a new gas CC to provide the products in the Shell and Iberdrola Contracts?

A. The annual capital costs are $81/kW-yr for the Shell Contract (in the range of $76-89/kW-yr depending on the assumed economic life) and $75/kW-yr for the Iberdrola Contract (in the range of $71-83/kW-yr depending on the assumed economic life). These estimates are derived by using a 9% after-tax cost of capital to estimate the carrying charges for a merchant generation developer as of 2001 to recover capital cost and financing costs. I calculated the annual carrying charges in level-real terms (i.e., flat annual

42 Actual costs from CEC Database of Proposed Generation Within the Western Electricity Coordinating Council (multiple 2001 vintages), combined with Interconnection Costs from the CPUC Revised 2004 Market Price Referent Staff Report.

Other studies summarized in Table 5 are:

CEC, "Comparative Cost of California Central Station Electricity Generation Technologies," June 5, 2003. Page 6.

MIT, "The Future of Nuclear Power, An Interdisciplinary MIT Study," 2003. Pages 43 & 145.

Note: Costs are expressed in 2001 $s by using Bureau of Labor Statistics CPI Inflation Calculator.

recovery in real dollars) over the economic life of the plant, which I assumed to be in the range of 20 to 30 years (with a base assumption of 25 years).[43]

Q. How do your assumptions on cost of capital, economic life of the new plant and annual capital costs compare to those used by Shell and Iberdrola in evaluating their long-term contracts with CDWR?

A. My assumption on cost of capital (9%) is similar to Shell's own assumptions for the discount rate in its evaluations of the economics of the CDWR contract and its gas CTs (the Wildflower Peaking Units), which ranged from of 9.5 - 10%.[44] My assumed range of 20 - 30 years for the economic life of a new gas CC is also consistent with Shell's own assumption for a gas CT (20 years)[45] and the typical range of 20 - 40 years assumed in other studies from the period. [redacted]

---

[43] The assumed economic life of 20-30 years is supported by the following studies:

CEC, "Comparative Cost of California Central Station Electricity Generation Technologies," June 5, 2003. Page 6.

CEC Staff, "Market Clearing Prices Under Alternative Resource Scenarios," 2000. Page 43.

MIT, "The Future of Nuclear Power, An Interdisciplinary MIT Study," 2003. Pages 43 & 145.

[44] Exh. No. CAL-651i; Exh. No. CAL-651ii (see "CashFlow" tab); Exh. No. CAL-652i; Exh. No. CAL-652ii (see "SUMMARY" tab).

[45] Exh. No. CAL-651ii (see "Inputs" tab).

[redacted] I also note that my estimate of annualized capital costs for a new gas CC in California exceeds the estimates developed by Dr. Tabors in his 2002 testimony in this proceeding on behalf of Dynegy.[47]

Q. In addition to capital costs, what other fixed costs did you include in estimating the annual costs to operate a gas CC?

A. I included fixed O&M costs, SCR operating costs, property tax expenses, and start-up costs. I calculated annual fixed costs as the sum of: (a) fixed O&M costs of $15/kW-yr (in 2001 $s) from AEO2001; (b) $2.1/kW-yr (in 2001 $s) for operating an SCR in California (for the Shell Contract only); (c) property tax expenses as 1% of capital costs; and (d) start-up costs as $1.1/kW-yr based on my analysis of expected annual starts per year. My estimates for non-capital annual fixed costs for a new gas CC are shown in Table 6.

---

[46] Exh. No. CAL-416 (PROTECTED).

[47] As described in Exh. No. DYN-34 at 4, Dr. Tabors estimated the annual capital cost of a new gas CC as $78/kW-yr.

Table 6
Estimated Annual Fixed Costs (excluding capital) of a New Gas CC

Year	**Shell ($/kW-Yr)**	**Iberdrola ($/kW-Yr)**
2005	27.89	24.74
2006	28.56	25.35
2007	29.26	25.98
2008	29.97	26.62
2009	30.71	27.28
2010	31.47	27.96
2011	32.26	28.66
2012	33.06	

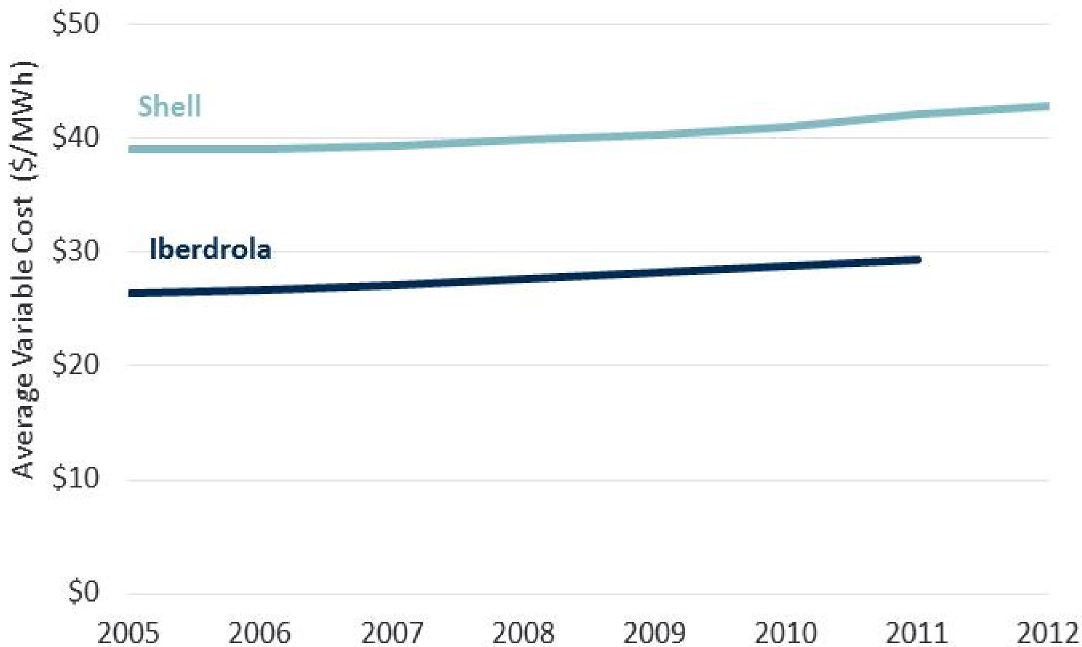
Q. What did you assume for variable costs to operate a gas CC?

A. For variable costs, I estimated fuel costs and variable O&M (VOM) costs. In addition, for the Shell Contract, I estimated the costs of operating SCR control equipment, and emission allowance costs for each MWh of energy output. For fuel costs, I relied on reported natural gas forward prices, and the typical heat rate for a new gas CC (6,970 Btu/kWh).[48] For variable O&M costs, I assumed $2.11/MWh for Shell and $2/MWh for Iberdrola based on: (1) $2/MWh VOM assumption for CCs, and (2) for Shell only,

[48] The assumed heat rate for a new gas CC was derived as the average of heat rates assumed in various studies including CEC studies, AEO2001, CPUC 2004 Market Price Referent Report, and Dr. Tabors' 2002 testimony.

SCR VOM cost estimate from EPA.[49] My estimates for the variable costs to operate a new gas CC are shown in Figure 20.

Figure 20
Variable Costs for a New Gas CC ($/MWh)



Q. How did you calculate the annual LRMC for each product in the Shell and Iberdrola Contracts based on your gas CC cost estimates?

A. The annual LRMC for each product equals annual variable costs plus levelized annual fixed costs for each product. To levelize the annual fixed costs for each product, I divided the annual fixed costs (in $kW-yr as

49 Analysis of Multi-Emissions Proposals for the U.S. Electricity Sector. EPA. Table A.1.3.c, Page 37.

described above) by the annual hours for that product, and multiplied by 1000 to express the costs in $/MWh.

Q. How did you determine the expected annual deliveries for each product in the Shell and Iberdrola Contracts?

A. As I described in Section II, the delivery volumes in the contracts were subject to several options for both buyer and seller. Therefore, I estimated the expected delivery volumes on a monthly basis as of the contract execution dates by comparing the expected market prices (based on TFS and Natsource data) against the expected avoidable (variable) prices under the contracts. In general terms, where the seller had optionality, I assumed that the seller would choose to sell not to CDWR, but to the market if the expected market price for the month was higher than the contract price for that month. Similarly, where CDWR had optionality, I assumed that CDWR would choose to buy not from the seller, but from the market when the expected market price was lower than the contract price. Exh. No. CAL-644 provides a more detailed description of the approach and assumptions I used in modeling volumes and prices for the Shell Contract; Exh. No. CAL-645 provides the same information for the Iberdrola Contract.

Q. Based on your analysis, what was the estimated annual LRMC for each product delivered in the Shell and Iberdrola Contracts?

A. The annual LRMC (in nominal $s) for each product in the Shell and Iberdrola Contracts are shown in Table 7 under each of my three different economic life assumptions.

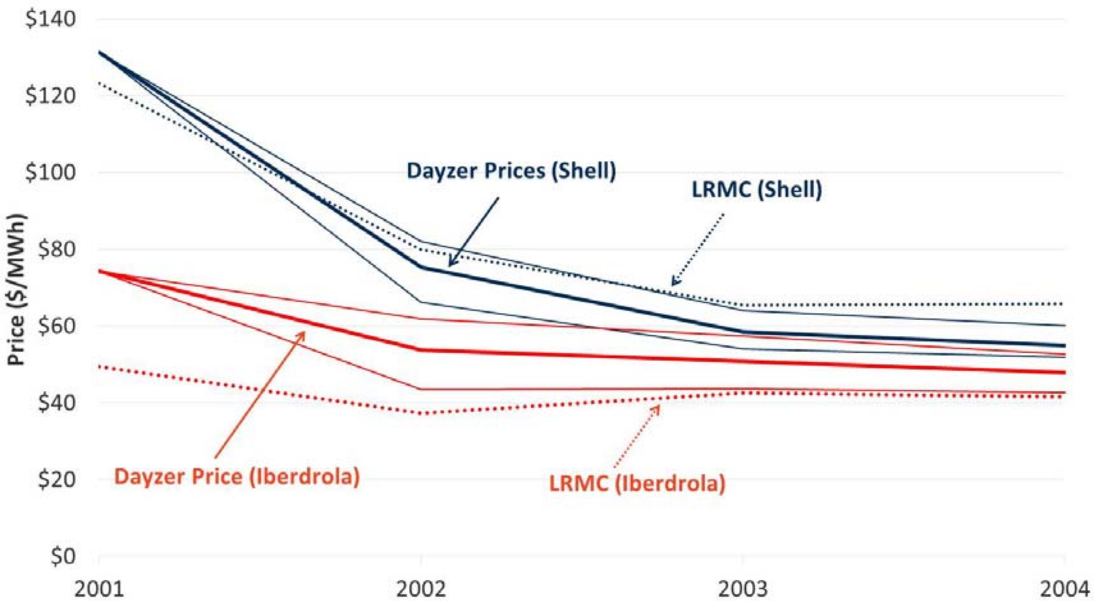
Table 7
Annual Long-Run Marginal Costs for Shell and Iberdrola Contracts
($/MWh)

Seller	Shell						Iberdrola		
Economic Life	20	25	30	20	25	30	20	25	30
Product	(7x24)	(7x24)	(7x24)	(6x16)	(6x16)	(6x16)	(7x24)	(7x24)	(7x24)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
2005	57.32	55.99	55.17	71.70	69 33	67.87	44.18	42.87	42.06
2006	57.87	56.51	55.67	72.68	70 24	68.75	45 00	43.66	42.84
2007	58.60	57.20	56.35	73.64	71.15	69.62	46 83	45.38	44.50
2008	59.51	58.08	57.20	74.84	72 30	70.74	47.78	46.31	45.40
2009	60.59	59.12	58.22	76.32	73.70	72.10	48 84	47.33	46.40
2010	61.77	60.26	59.34	78.03	75 34	73.70	49 93	48.37	47.42
2011	63.45	61.91	60.96	80.13	77 37	75.68	103.36	97.93	94.61
2012	89.05	85.69	83.63	124.80	118.85	115 20			

Q. You previously stated that your DAYZER-simulated prices would allow for recovery of the all-in costs of a hypothetical new gas CC that came online in 2001. Did you conduct an analysis of long-run marginal costs for the period 2001-2004 to support this finding?

A. Yes. As Figure 21 shows, I estimated the LRMC of a hypothetical new gas CC unit coming online in 2001 using the same methodology I described above for a new gas CC unit coming online in 2005. The main difference between the two LRMC estimates is that the assumed variable fuel costs for the 2001 - 2004 period were higher than the post-2005 period due to higher natural gas forward prices for the earlier years. Figure 21 demonstrates that the DAYZER-simulated prices for 2001 – 2004 (solid lines) are similar to the LRMC-based prices for the same period (dashed lines).

Figure 21
Estimated Prices for the 2001-2004 Period
(DAYZER Range vs. LRMC)

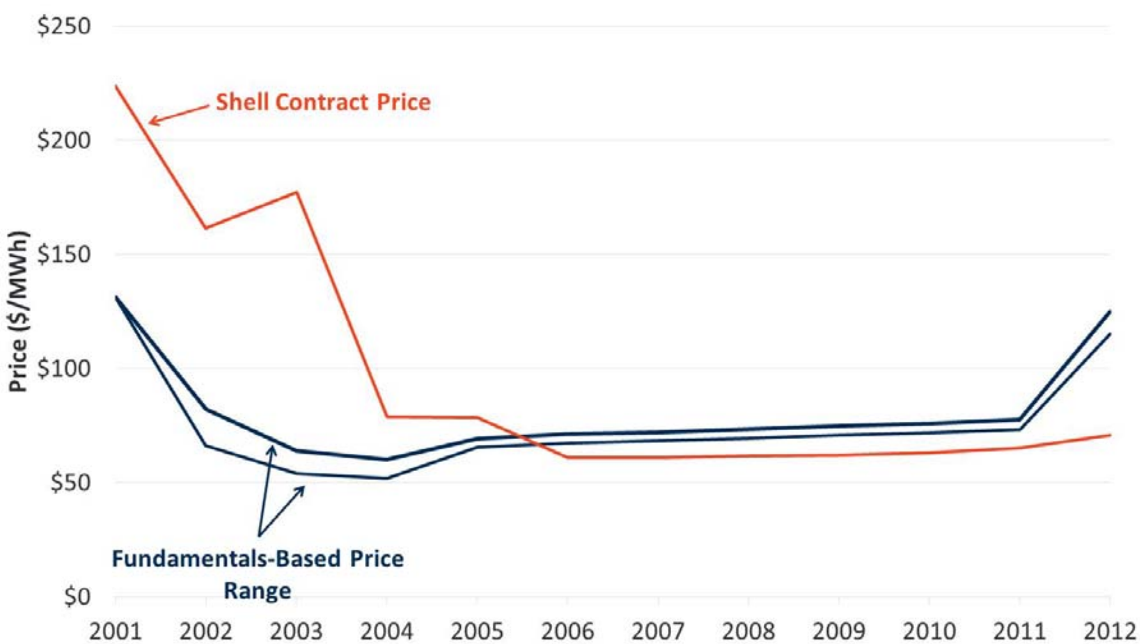


3. Costs of the Shell and Iberdrola Contracts Relative to Fundamentals-Based Prices

Q. Please compare your fundamentals-based prices to the Shell Contract prices for the entire contract term.

A. Figure 22 compares Shell Contract prices (in red) against the estimated range of fundamentals-based prices (in blue) during the period 2001 – 2012 (DAYZER simulations for the near term and the LRMC projections for the later years). Contract prices were substantially higher than fundamentals-based prices during the initial years, but close to fundamentals-based prices in the later years. Both contract prices and fundamentals-based prices were projected based on expected delivery volumes as described in Exh. No. CAL-644.

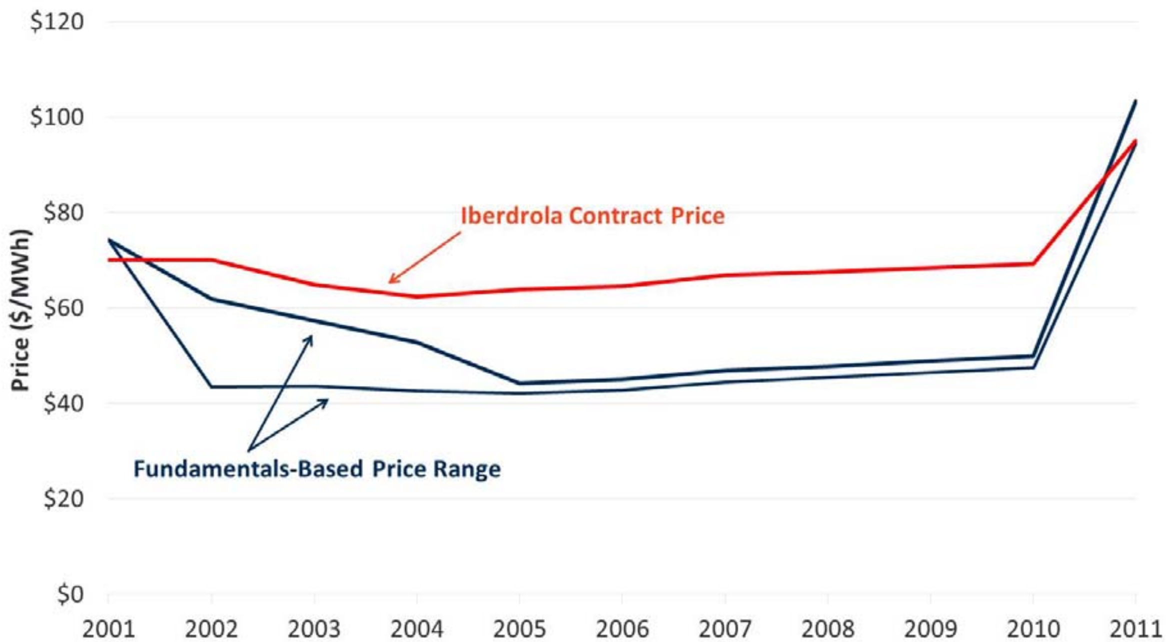
Figure 22
Shell Contract Prices vs. Fundamentals-Based Prices ($/MWh)



Q. **Please compare your fundamentals-based prices to the Iberdrola Contract prices for the entire contract term.**

A. As shown in Figure 23, Iberdrola Contract prices (in red) exceeded fundamentals-based prices (in blue) in all years except 2001 and 2011. DAYZER simulations were used for the near term and the LRMC projections for the later years, and both contract prices and fundamentals-based prices were projected based on expected delivery volumes as described in Exh. No. CAL-645.

Figure 23
Projected Iberdrola Contract Prices vs. Competitive Prices ($/MWh)



Q. How did you calculate the difference in payments under the contract prices and fundamentals-based prices?

A. I estimated the payment differential (in nominal $s) in each contract by multiplying the difference between contract and fundamentals-based prices for each month by the monthly projected volume in that month. [redacted] I then applied FERC quarterly interest through May 2015.

Q. Based on your analysis, what was the cost of the Shell Contract in comparison to fundamentals-based prices?

A. I estimate that projected payments under the Shell Contract prices exceeded the projected payments under fundamentals-based prices by $779 million (in the range of $624 million to $890 million), including FERC interest to May 2015. The range in estimates results from use of different assumptions concerning hydro conditions in the DAYZER analysis, and different assumptions of the new gas CC's economic life expectancy in the LRMC analysis. Table 8 shows the burden by year under the various assumptions.

Table 8
Burden in Shell Contract Compared to Fundamentals-Based Prices
(Million $)

	Economic Burden (Nominal)			Economic Burden (FERC Interest as of May 31, 2015)		
Economic Life	**25**	**30**	**20**	**25**	**30**	**20**
Hydro Assumption	**Base**	**Wet**	**Dry**	**Base**	**Wet**	**Dry**
Units	**$Million**	**$Million**	**$Million**	**$Million**	**$Million**	**$Million**
2001	**45.5**	45.5	45.5	**87.4**	87.4	87.4
2002	**125.1**	138.3	115.2	**225.8**	249.6	207.8
2003	**308.8**	320.3	294.3	**532.2**	552.1	507.3
2004	**85.4**	96.4	66.8	**141.3**	159.6	110.5
2005	**44.5**	49.7	36.0	**70.4**	78.7	56.9
2006	**-28.2**	-23.1	-36.5	**-41.8**	-34.3	-54.1
2007	**-30.8**	-25.6	-39.3	**-42.2**	-35.0	-53.8
2008	**-33.4**	-28.0	-42.1	**-42.3**	-35.5	-53.3
2009	**-36.6**	-31.1	-45.5	**-44.3**	-37.7	-55.1
2010	**-29.3**	-24.9	-36.5	**-34.4**	-29.2	-42.8
2011	**-22.5**	-18.9	-28.4	**-25.6**	-21.5	-32.2
2012	**-43.7**	-40.4	-49.1	**-48.0**	-44.4	-54.0
With FERC Interest (as of May 31, 2015)				**778.6**	889.7	624.4

Q. What was the cost of the Iberdrola Contract in comparison to fundamentals-based prices?

A. I estimate that payments under the Iberdrola Contract exceeded payments under fundamentals-based prices by $371 million (in the range of $295 to $445 million), including FERC interest to May 2015. As with the Shell Contract, the range in estimates results from use of different assumptions concerning hydro conditions in the DAYZER analysis, and different assumptions of the new gas CC's economic life expectancy in the LRMC analysis. Table 9 shows the burden by year under the various assumptions.

Table 9
Burden in Iberdrola Contract Compared to Fundamentals-Based Prices
(Million $)

	Economic Burden (Nominal)			Economic Burden (FERC Interest as of May 31, 2015)		
Economic Life	**25**	**30**	**20**	**25**	**30**	**20**
Hydro Assumption	**Base**	**Wet**	**Dry**	**Base**	**Wet**	**Dry**
Units	**$Million**	**$Million**	**$Million**	**$Million**	**$Million**	**$Million**
2001	**-2.3**	-2.3	-2 3	**-4.5**	-4.5	-4 5
2002	**25.0**	40.7	12.4	**45.1**	73.5	22.4
2003	**12.2**	21.2	4 2	**21.1**	36.5	7 2
2004	**19.4**	28.2	11.1	**32.2**	46.7	18.4
2005	**36.0**	37.6	33.4	**56.9**	59.4	52 8
2006	**35.6**	37.2	32 9	**52.8**	55.2	48 9
2007	**34.9**	36.6	32 2	**47.8**	50.0	44.1
2008	**34.5**	36.2	31.7	**43.7**	45.9	40 2
2009	**34.1**	35.8	31 2	**41.3**	43.4	37 8
2010	**33.6**	35.4	30.7	**39.4**	41.5	36 0
2011	**-4.3**	-2.4	-7 2	**-4.8**	-2.8	-8 2
With FERC Interest (as of May 31, 2015)				**371.0**	444.9	295 2

IV. ANALYSIS OF THE ECONOMIC BURDEN CAUSED BY ALL CDWR LONG-TERM CONTRACTS

Q. Were the Shell and Iberdrola Contracts the only long-term contracts CDWR negotiated and executed during the Crisis?

A. No, besides the Shell and Iberdrola Contracts, CDWR executed approximately 50 additional long-term contracts in 2001.

Q. What were the actual volumes of energy delivered under all CDWR Long-Term Contracts for the period October 2001 through December 2014?

A. Approximately 480 million MWh. The annual contract volumes started at 34 million MWh in 2002, peaked at 63 million MWh in 2004, and reduced to 0.31million MWh by 2013.[50]

Q. What were the actual costs paid under all CDWR Long-Term Contracts for the period October 2001 through December 2014?

A. $36.47 billion, at an average "all-in" price of $75.92/MWh (nominal $s).[51]

Q. Have you analyzed the burden imposed on California consumers by the entire portfolio of CDWR Long-Term Contracts?

A. Yes. Similar to the methodology I described above for the Shell and Iberdrola Contracts, I compared the actual payments under all CDWR

---

[50] Pacheco Direct Testimony, Exh. No. CAL-214 at 17; Exh. No. CAL-216; Exh. No. CAL-217; and Exh. No. CAL-218 (summary of CDWR Long-Term Contract deliveries and payments).

[51] *Id.*

Long-Term Contracts to the payments that CDWR could have made for the same volumes under the forward market prices available in September 2001, when the markets were no longer dysfunctional. One key difference is that I did not attempt to match the exact product characteristics in each CDWR contract other than the Shell and Iberdrola Contracts. Instead, I conservatively assumed that deliveries were made in the form of on-peak (6x16) products at the California trading hub with the highest price in each month, even though some of the CDWR contracts delivered less valuable products (e.g., off-peak or clock-hour) at delivery locations with lower prices.

Q. What would CDWR's payments have been for the actual volumes of energy delivered under all CDWR Long-Term Contracts for the period October 2001 through December 2014 at the post-Crisis forward market prices?

A. $20.50 billion, at an average price of $42.66/MWh (nominal $s).

Q. Based on your analysis, what was the burden imposed on consumers by all CDWR Long-Term Contracts?

A. $15.93 billion (nominal $s), with a resulting price difference of $33.16/MWh. With FERC quarterly interest charges through May 2015, the burden increases to $24.49 billion. Figure 24 shows the annual actual payments under all CDWR Long-Term Contracts against the payments under post-Crisis forward market prices. Figure 25 and Table 10 demonstrate the annual averages of actual contract prices against post-Crisis forward market prices.

Figure 24
Actual Payments under all CDWR Long-Term Contracts vs. Post-Crisis Forward Market -Based Payments (Nominal $s)

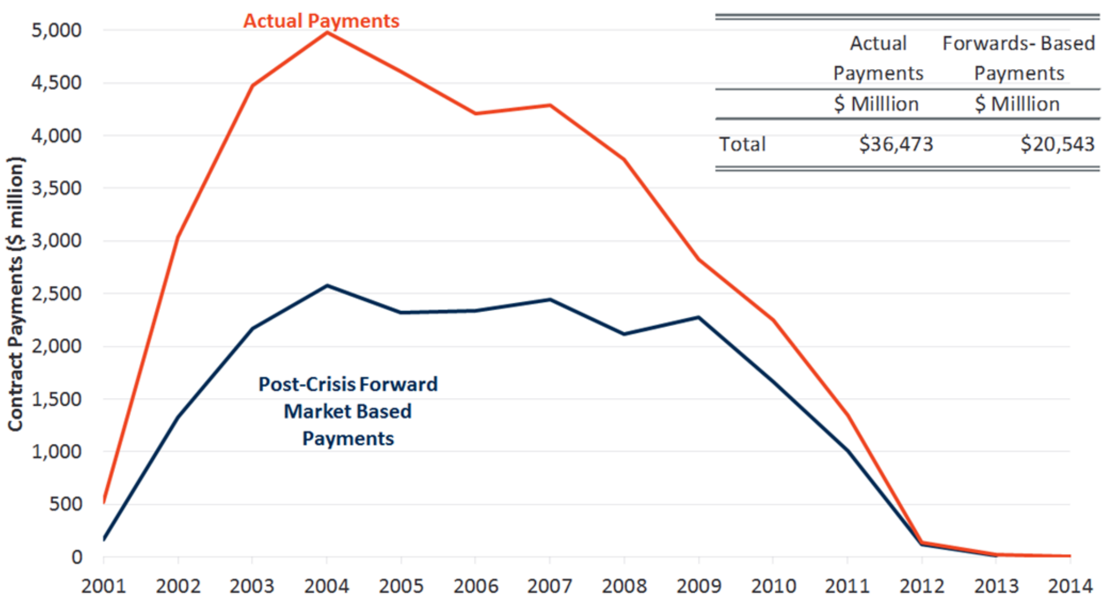


Figure 25
Actual Average Prices under all CDWR Long-Term Contracts vs. Post-Crisis Forward Market Prices (Nominal $s) [52]

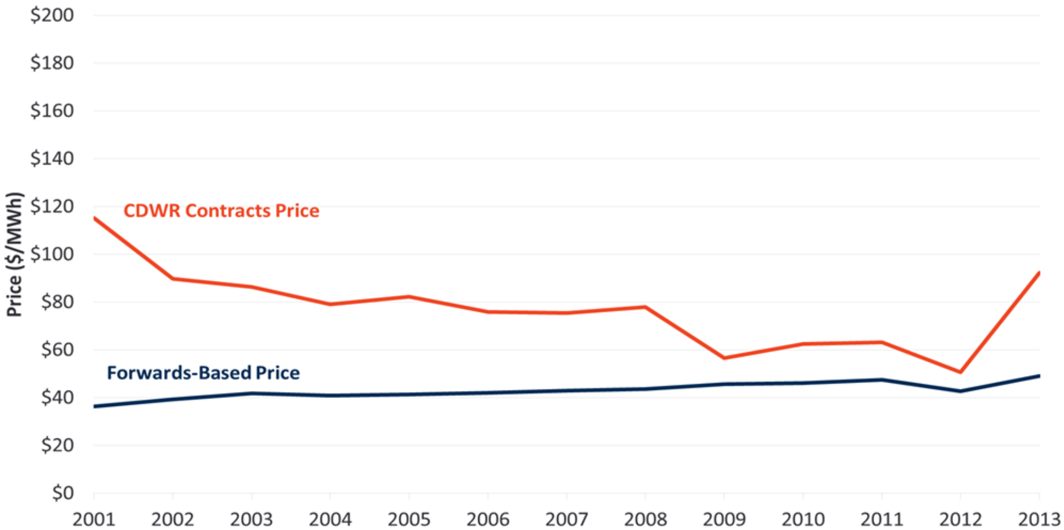


Table 10
Actual CDWR Long-Term Contract Prices vs. Post-Crisis Forward Market Prices ($/MWh)

Year	Volumes	Actual Price	Forwards-Based Price
	(MWh)	*($/MWh)*	*($/MWh)*
2001	4,532,585	$115	$36
2002	33,832,601	$90	$39
2003	51,939,213	$86	$42
2004	63,023,557	$79	$41
2005	56,107,350	$82	$41
2006	55,503,629	$76	$42
2007	56,854,318	$75	$43
2008	48,445,675	$78	$44
2009	49,891,999	$57	$46
2010	36,027,411	$62	$46
2011	21,215,623	$63	$47
2012	2,755,679	$51	$43
2013	309,701	$92	$49

52 The price for 2014 is not presented in the graph because there were not any power deliveries; however the CDWR still had gas costs during this period.

V. CONCLUSIONS

Q. Dr. Celebi, would you please summarize the results of your analyses?

A. My analyses demonstrate conclusively that the Shell and Iberdrola Contracts, negotiated and executed during the Crisis, caused an excessive burden on California consumers "down the line" relative to energy prices that CDWR could have obtained when the markets were no longer dysfunctional.

First, my assessment of other long-term contracts confirmed that the Shell and Iberdrola Contract prices were substantially higher than the prices in comparable contracts executed in the September 2001 – December 2002 post-Crisis period.

Next, I quantified the "down the line" economic burden caused by the Shell and Iberdrola Contracts by comparing CDWR's actual payments to the payments it would have made under the post-Crisis forward market prices for comparable products and deliveries. The forward prices reported by energy brokers during trading days in September 2001 – adjusted to account for differences in non-price terms in the CDWR contracts – represent my best estimate of the market prices that would have been available to CDWR for substitute power after the Crisis ended, and thus serve as the most appropriate reference point for quantifying consumer harm. This methodology calculates the down the line burden for each contract as follows:

	Down the Line Burden (nominal $s)	**Down the Line Burden (with FERC interest through May 2015)**
Shell Contract	$1.37 billion	$2.14 billion
Iberdrola Contract	$601 million	$875 million

I then corroborated my down the line burden findings by comparing the Shell and Iberdrola Contract prices with estimated prices based on expectations concerning the underlying cost elements of producing electric power as of the contract execution dates. I used market simulation software to estimate locational marginal prices for near-term deliveries (2001 – 2004), and prices consistent with long-run marginal costs for the later year deliveries (2005 – 2012). I conclude that projected payments under the Shell and Iberdrola Contract prices exceed payments under these fundamentals-based payments by $779 million for the Shell Contract, and $371 million for the Iberdrola Contract, with FERC interest through May 2015. These findings reinforce that the Shell and Iberdrola Contract prices substantially exceeded the prices a good faith seller could have expected to achieve in an arms-length transaction from an uncoerced buyer as of the execution dates

Finally, to demonstrate in fuller extent the burden imposed on consumers by the Crisis, I extended my post-Crisis forward market price analysis to all CDWR Long-Term Contracts executed when the Western markets were dysfunctional. I estimate the economic burden caused by all CDWR Long-Term Contracts relative to post-Crisis prices as $24.49 billion ($15.93 billion principal plus FERC interest).

Q. Does this conclude your testimony?

A. Yes.