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Witness: Tony Choi

Date: June 1, 2010

SAN DIEGO GAS & ELECTRIC COMPANY

PREPARED DIRECT TESTIMONY OF

TONY CHOI

REDACTED AND PUBLIC VERSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

June 1, 2010

#231224

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PREPARED DIRECT TESTIMONY OF

TONY CHOI

ON BEHALF OF SDG&E

I. INTRODUCTION

This testimony presents San Diego Gas & Electric Company's (SDG&E's) compliance with least-cost dispatch (LCD) requirements during the Record Period of January 1 through December 31, 2009, as specified by applicable Commission decisions. LCD pertains to the day-ahead and intra-day dispatch and trading of SDG&E's portfolio of resources, including utility-owned generation (UOG), power purchase contracts and allocated Department of Water Resources (DWR) contracts. The following chapters describe Commission orders on LCD and how SDG&E implemented these orders in a manner consistent with its Commission-approved Long-Term Procurement Plan (LTPP)[1], both before and after the CAISO's launch of the Market Redesign and Technology Upgrade (MRTU) on April 1, 2009.

SDG&E has filed four quarterly advice letters covering the Record Period (AL 2080-E, AL 2098-E, AL 2121-E, and AL 2143-E for Q1 through Q4 2009, respectively) as required by the Master Data Request in D.02-10-062. These advice letters provide detailed information on transactions that SDG&E executed while following its LCD process, as well as other data (e.g. customer load, resource schedules and fuel transactions) pertinent to the LCD process during the Record Period. The Commission's Utility Audit, Financial, and Compliance Branch (UAFCB) has completed its compliance audits of all four of SDG&E's Quarterly Compliance Reports ("QCR") for 2009 concluding that SDG&E's QCR transactions for electricity and natural gas were materially complete, accurate, properly authorized and in compliance with SDG&E's Commission-approved procurement plan and all relevant Commission decisions. Moreover, with the exception of SDG&E's Q4 QCR, for which approval is currently pending, the Commission's Energy Division issued its approvals establishing that the procurement transactions reflected in SDG&E's QCRs were in compliance with SDG&E's Commission-

[1] SDG&E's LTPP was approved in D.07-12-052. The compliance filing was approved in Resolution E-4189 on September 4, 2008. It has been subsequently modified by two Advice Letters, AL 2061-E in January 2009, and AL 2067-E, both approved by the Energy Division by letter.

approved, AB57 Long Term Procurement Plan, and applicable procurement-related rulings and decisions.[2]

II. COMMISSION DIRECTION FOR LEAST COST DISPATCH

In D.02-09-053, which allocated the DWR contracts to the three California investor owned utilities (IOU), the Commission charged the IOUs with the responsibility to "assume all the operational, dispatch and administrative functions"[3] for the allocated contracts and directed that "economic dispatch shall be the operating rule for the utility's portfolio of resources, including the DWR contracts."[4] This decision also provided direction by which a utility should implement LCD of the combined utility/DWR portfolio. D.02-09-053 states: "[E]conomic dispatch entails analysis of the marginal costs of the available energy and dispatching the least-cost incremental resource. An important element of least cost dispatch is that the fixed costs associated with resources are considered sunk for dispatch purposes. Variable costs are the only ones that are incurred or avoided as a result of operating decisions."[5]

The LCD requirement was reiterated by the Commission in D.02-10-062, which authorized the IOUs to resume full procurement responsibilities on January 1, 2003. That decision established standards of conduct by which an IOU must administer its portfolio, including the allocated DWR contracts. Specifically, Standard of Conduct #4 (SOC 4) states that "[t]he utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[6] In a subsequent decision, the Commission provided further guidance on LCD by affirming that "least cost" activities include the purchase and sale of power to achieve the most cost-effective mix of resources and minimize cost to ratepayers:

> Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, to include dispatching dispatchable contracts when it is most economical to do so. In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. Least-cost dispatch refers to a situation in which the most cost-effective mix of

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2 D.02-10-062, COL 7, p. 73; D.03-12-062, pp. 78-79; OP 20 and, D.07-12-052, pp. 185 -192.
3 D.02-09-053, Ordering Paragraph 2.
4 D.02-09-053, Ordering Paragraph 5.
5 D.02-09-053, p. 30-31.
6 D.02-10-062, p. 51 and Conclusion of Law 11, p. 72.

total resources is used, thereby minimizing the cost of delivering electric services.

The utility bears the burden of proving compliance with the standard set forth in its plan.[7]

Further Commission guidance was provided in R.04-04-003 in response to a CAISO request that the IOUs assist with the management of intra-zonal congestion. R.04-04-003 established that the IOUs account for intra-zonal congestion in their procurement and scheduling decisions to mitigate the CAISO's reliability concerns. R.04-04-003 was followed by D.04-07-028, requiring IOUs to assess the potential for intra-zonal congestion when procuring and scheduling resources. In response to D.04-07-028, SDG&E filed Advice Letter 1641-E on 12/3/2004 describing its revised LCD procedure incorporating a new cost adder to account for anticipated intra-zonal congestion costs.

Finally, with regard to review of LCD transactions in ERRA proceedings, the Commission determined in D.05-01-054 (SDG&E's 2004 ERRA compliance decision) that the scope of LCD review should cover the dispatch of resources in the day-ahead, hour-ahead and real-time markets. The Commission reiterated this scope of review in D.05-04-036 (PG&E's 2004 ERRA compliance decision).

III. PRINCIPLES OF LEAST COST DISPATCH

The goal of least cost dispatch is to minimize ratepayer cost for energy and ancillary services (A/S) given prevailing market conditions. SDG&E achieved this objective by planning, trading, scheduling and bidding to economically optimize the dispatch of its resources and market transactions to lower overall cost. Planning involves a thorough assessment of the portfolio's dispatch economics to determine the lowest cost mix of resources to meet forecasted load. Trading makes least cost dispatch "happen" by finalizing resource schedules and executing economic market transactions, including sales of surplus generation above variable cost. Scheduling and bidding, especially post-MRTU, enables the CAISO markets to dispatch resources in line with variable operating costs in real-time. Performance of these functions essentially embodies the least cost principles established by the Commission. How SDG&E performs each of these functions is discussed in the following sections.

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[7] D.03-06-076 at p. 23.

A crucial footnote is that there are numerous constraints that impede SDG&E's ability to perfectly adhere to these least cost dispatch principles. SDG&E must balance its objective of cost minimization with a number of constraints both within and outside the portfolio. They include generator operating limits, regulatory requirements, risk mitigation and other drivers that are discussed in Section IX.

IV. MRTU OVERVIEW

The CAISO implemented MRTU on April 1, 2009, which fundamentally changed several processes that impact least cost dispatch. The most significant of these changes was the implementation of forward markets, which transferred to the CAISO the responsibility to determine day-ahead and intraday unit commitment and dispatch decisions (also referred to as "awards") for resources based on economic bids. Prior to MRTU, market participants decided which units to commit and schedule on a day-ahead basis, with the requirement that load serving entities (LSEs) meet at least 95% of the day-ahead load forecast with generation schedules or market purchases[8]; the CAISO then dispatched remaining capacity for system reliability if needed.

Post-MRTU, the CAISO now operates the day-ahead and intraday markets that establish commitment, energy and A/S obligations on resources in the system. These markets derive generation awards from supply and demand bids and self-schedules submitted by market participants. The results reflect a least cost dispatch solution across the entire system because the CAISO selects the mix of resources with the lowest total variable cost (as represented by their bids) to meet load requirements, subject to reliability and operational requirements.

Another significant post-MRTU feature is that day-ahead awards on resources and load are financially binding obligations. Deviations between these awards and actual energy delivery (or load consumption) trigger settlement charges with the CAISO at real-time prices, as described further in Section VIII.D of this testimony. Prior to MRTU, day-ahead energy schedules were not financially binding, so market participants were allowed to revise its day-

[8] Prior to MRTU, SDG&E complied with CAISO Amendment No. 72, which requires LSEs to schedule at least 95% of forecasted load during on-peak hours and at least 75% of forecasted load during off-peak hours in the day-ahead market. Amendment 72 also required LSEs to report forecast and scheduled loads to the FERC on a weekly basis. This amendment expired upon launch of MRTU.

ahead load, generation and transaction schedules up until the final hour-ahead scheduling deadline without incurring a settlement charge from the CAISO[9].

Post-MRTU, the CAISO solves for the day-ahead and intraday commitment and dispatch solution based on a full transmission network model that reflects congestion throughout the CAISO system, versus the much simpler zonal model used prior to MRTU. The awards explicitly account for the economic effects of congestion, e.g. cost to re-dispatch resources to relieve congestion constraints. The congestion cost is published for each of the several thousand price nodes in the CAISO system, which eliminates the need for SDG&E to estimate intra-zonal congestion costs in its LCD process as done prior to MRTU.

The day-ahead market also introduced an improved process by which the CAISO procures ancillary services. Before MRTU, the CAISO operated a day-ahead market for A/S only. However, awards relied on bid prices submitted for quantities not already scheduled against load requirements or market sales. Under MRTU, the day-ahead market co-optimizes the allocation of dispatchable capacity between generation and A/S capacity, based on prices submitted for each of these services in the resource bids[10]. The resulting allocation of awards between generation and A/S across the system was therefore more efficient because it reflects the economic tradeoff between capacity used for generation and that reserved for A/S.

MRTU implementation caused SDG&E's volume of power trades to decline both in the day-ahead and hour-ahead markets. Lower volume was due to lack of market liquidity, likely caused by higher clearing costs imposed by the CAISO post-MRTU and the tendency for the CAISO to change settlement prices after-the-fact. Market liquidity shifted away from CAISO energy products towards over-the-counter (OTC) financial power swaps because they have lower transaction costs and carry lower risk of after-the-fact price changes, since they do not clear through the CAISO. These products, authorized under SDG&E's LTPP, are short-term swaps that trade at a fixed price and settle against the CAISO-generated day-ahead or real-time market price. SDG&E adopted day-ahead financial power transactions shortly after MRTU implementation to hedge *ex-ante* the risk of unknown day-ahead market clearing prices. Like

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9 Prior to MRTU, day-ahead A/S awards were financially binding. Failure to deliver the A/S product awarded in the day-ahead market resulted in a CAISO charge to either rescind the award payment or purchase make-up A/S in the real-time market.

10 As a simple example, if a generator's energy bid price is $10/MWh in-the-money relative to the clearing price, then the IFM will award the generator an A/S award only if it the A/S clearing price exceeds $10 or the generator's bid, whichever is greater.

physical power purchases, SDG&E purchased financial power to lock in energy prices below its marginal generation cost, and sold financial power to lock in sales of surplus generation above variable cost. SDG&E traded these products on the Intercontinental Exchange (ICE) or through voice brokers to ensure competitive prices, and submitted these trades for Commission review in its Quarterly Compliance Reports.

V. SDG&E PORTFOLIO OVERVIEW

For the Record Period, most of SDG&E's energy requirements were met with SDG&E-contracted purchase power agreements (PPAs), utility-owned generation and allocated DWR contracts. SDG&E's PPAs included Qualifying Facility (QF) contracts and contracts for renewable energy contracts, dispatchable generation and out-of-state resources. Utility-owned generation included a 20% share of SONGS, Palomar Energy Center combined-cycle plant and Miramar 1 and 2 combustion turbine (CT) generators. Allocated DWR contracts included two must-take system power contracts, two wind contracts, three CTs and Sunrise combined cycle plant.

For the Record Period, the most significant changes to SDG&E's portfolio were the additions of the Otay Mesa Energy Center PPA (604 MW) in October 2009, completion of the Miramar 2 project (48 MW) in August 2009 and the commencement of an RPS-related import contract from Palo Verde (200 MW) in October 2009.

The table below provides summary data for resources in the SDG&E/DWR portfolio and highlights key changes resulting from the transition to MRTU.

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Must-Take Resources

Resource	Capacity MW	Dispatch Profile	Ancillary Service Capability
SONGS (nuclear)	450	Baseload	None
QF contracts	221	Baseload w/ limited economic curtailment	None
Renewable (non-wind) contracts	97	Baseload (as available)	None
Renewable wind contracts (includes DWR wind contracts)	217 (maximum)	Intermittent	None
SP15 long-term market energy (DWR contract)	325	On-Peak Block (6x16)	None
System Resource imports	203	Baseload (7x24)	None

*Although located in San Diego County, SONGS is electrically not a San Diego local resource.

Dispatchable Resources

Resource*	Capacity MW	Dispatch Profile	Ancillary Service Capability
Palomar CCGT Natural Gas SP26	565	Load Following	Spinning Reserve Regulation
Otay Mesa CCGT Natural Gas SP26	604	Load Following	Spinning Reserve Regulation
Sunrise CCGT Natural Gas ZP26	590	Load Following	None
Calpeak Border CT* Natural Gas SP26	49	Peaker	None
Calpeak El Cajon CT Natural Gas SP26	49	Peaker	None
Calpeak Escondido CT Natural Gas SP26	49	Peaker	None
Miramar 1 CT Natural Gas SP26	48	Peaker	Non-Spinning Reserve
Miramar 2 CT Natural Gas SP26	48	Peaker	Non-Spinning Reserve
Boardman Coal ST Coal Malin	83	Baseload	None
Encina Unit 1 ST Natural Gas SP26	106	Peak Load Following	Spinning Reserve
Encina Unit 2 ST Natural Gas SP26	104	Peak Load Following	Spinning Reserve Regulation

Encina Unit 3 ST Natural Gas SP26	110	Peak Load Following	Spinning Reserve Regulation
Encina Unit 4 ST Natural Gas SP26	300	Peak Load Following	Spinning Reserve Regulation
Encina Unit 5 ST Natural Gas SP26	330	Peak Load Following	Spinning Reserve Regulation
Encina CT Natural Gas SP26	14	Peaker	Non-Spinning Reserve
South Bay Unit 1 ST Natural Gas SP26	145	Peak Load Following	Spinning Reserve Regulation
South Bay Unit 2 ST Natural Gas SP26	149	Peak Load Following	Spinning Reserve Regulation
South Bay Unit 3 ST Natural Gas SP26	174	Peak Load Following	Spinning Reserve
South Bay Unit 4 ST Natural Gas SP26	221	Peak Load Following	Spinning Reserve
South Bay CT Jet Fuel SP26	15	Peak Load Following	Non-Spinning Reserve

* CCGT = Combined Cycle Gas Turbine; CT = Combustion Turbine; ST = Steam Turbine

VI. SDG&E-OWNED GENERATION

During the Record Period, SDG&E operated and maintained its utility-owned generation resources[11] (Palomar, Miramar 1 and 2) consistent with Good Utility Practice, defined by the Commission as "… any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice does not require the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the Western Electric Coordinating Council region."

SDG&E established and followed a maintenance program to maximize the availability of the units as a primary "desired result". Specifically, this maintenance program balanced a number of considerations including manufacturer guidelines, appropriate power industry

[11] SDG&E owns 20% of SONGS but the plant is operated and maintained by SCE.

practices and good technical judgment to allocate resources most effectively to maximize availability. Some of these maintenance requirements required planned outages to perform, while corrective maintenance was performed under short-notice or forced outages.

Of note, SDG&E completed the installation of chiller equipment at the Palomar unit during the Record Period. The chiller is designed to cool the combustion turbine inlet air temperature, enabling the unit to achieve maximum availability during summer peak load hours when capacity is most valuable.

During the Record Period, the Palomar units (two combustion turbine-generators and a steam turbine-generator) achieved Availability Factors (AFs) of [redacted] respectively. These values are [redacted] the most recent combined cycle industry average as reported by NERC-GADS of 90%, based on 2004-2008 data. During the Record Period, Miramar 1 and 2 achieved AFs of [redacted] respectively, also [redacted] with the industry average of 93% for comparable units.

Despite SDG&E performing maintenance on its generation resources consistent with Good Utility Practice, these units experienced forced outages from time to time due to unforeseen operational problems. These outages are summarized in Appendix 1. When SDG&E experienced a forced outage on Palomar, Miramar 1 or 2, or any other resource in its portfolio, it responded to the event based on LCD principles. To the extent feasible based on scheduling, market liquidity and other constraints, SDG&E sought to replace lost generation due to forced outages at the minimum cost. This process is discussed in Section VIII.D.

VII. FUEL PROCUREMENT

During the Record Period, SDG&E supplied fuel to all natural gas-fire dispatchable resources in the portfolio. SDG&E performed as the pipeline-registered Fuel Manager and Fuel Supplier for all non-DWR dispatchable resources (Miramar peakers, Palomar, Otay Mesa, Encina and South Bay power plants). SDG&E also performed both Fuel Manager and Fuel Supplier functions as DWR's agent for Sunrise, but only the Fuel Supplier function as DWR's agent for the Calpeak units. Fuel costs for SDG&E resources are charged to ERRA, while fuel costs for DWR resources are paid by DWR and recovered through the DWR retail remittance rate. No preference is given to either SDG&E or DWR resources despite the difference in fuel cost recovery mechanism; SDG&E dispatches all units based strictly on variable dispatch costs and operational constraints.

As discussed in the Commission-approved LTPP and SDG&E / DWR Gas Supply Plan, SDG&E's procurement strategy is to secure approximately 90% of forecasted fuel volumes required to serve SDG&E's load forecast (but not economic sales) as firm monthly baseload supply. The advantages of baseload supply are that it 1) shields ratepayers from potentially volatile day-ahead natural gas prices, 2) is scheduled by market participants as a higher priority delivery than day-ahead supply and 3) reduces the day-to-day trading and scheduling requirements thereby reducing overall operational requirements. While the cost of baseload supply may be lower or higher than the spot price on any given day, over time these price differentials average toward zero, leaving SDG&E with the benefits cited above.

While most fuel supply was procured as firm monthly baseload, SDG&E at all times used prevailing day-ahead or intraday market prices to price out day-ahead or intraday generation costs, which is consistent with LCD. For example, if the portfolio was short fuel relative to day-ahead requirements, fuels traders purchased incremental supply at the day-ahead market price. Or, if the portfolio was long fuel relative to real-time requirements, fuels traders sold the surplus baseload supply at the same-day market price. This coordination between the fuels and power desks enabled SDG&E to accurately price variable generation costs so that the benefits of market transactions could be properly evaluated. Both baseload and daily natural gas trades for the Record Period were executed at competitive prevailing market prices and in compliance with the LTPP. The delivery points for the natural gas deals booked to ERRA were the various SoCal Border delivery points or the SoCalGas Citygate trading hub, since all (non-DWR) dispatchable resources in the portfolio use natural gas supplied at these points. All natural gas transactions were reported and are reviewed by the Commission in SDG&E's Quarterly Compliance Reports under the advice letters cited in Section I.

SDG&E also entered into financial transactions to hedge fuel costs during the Record Period. Hedge transactions consisted primarily of futures and basis swap purchases which together fixed the forward price of the monthly NGI SoCal Border index. Futures trades were executed through the NYMEX exchange. Basis swaps were executed over-the-counter (OTC) directly with counterparties or through voice brokers and typically cleared through ICE Clear, a widely used clearinghouse for OTC trades. Prior to finalizing a basis swap directly with a counterparty, SDG&E simultaneously secured competitive offers from two to six other sellers to ensure the swap was priced competitively. These hedge transactions complied with the LTPP and internal quarterly hedge plans, and were submitted for Commission review in SDG&E's Quarterly Compliance Reports.

Throughout the Record Period, SDG&E held approximately [redacted] MMBtu/day of Firm Access Rights (FARs) to transport natural gas from the various SoCal Border trading points to the SoCalGas Citygate. SDG&E purchased the FAR capacity from SoCalGas pipeline to increase the priority of fuel delivery to its dispatchable resources. The quantity of FARs represented a forecast of the average daily fuel usage of these resources over the year. If fuel requirements were less than the FAR quantity on a given day, SDG&E sought to mitigate the capacity cost by monetizing the FARs via locational spreads (purchase at SoCal Border and sale at SoCalGas Citygate) in the day-ahead market when the spread exceeded transaction costs. SDG&E submitted Advice Letter 1983-B on July 3, 2008 to amend its LTPP to include FARs as a Commission-approved product to serve load.

SDG&E also bid for and was awarded SoCalGas system storage capacity that was in effect from April 1 through December 31 of the Record Period. Storage was required to manage day-to-day imbalances between natural gas deliveries and actual consumption that occurred on a daily basis. Imbalances were mainly caused by CAISO-instructed incremental or decremental real-time dispatches that deviated from the day-ahead LCD forecast. Significant imbalances resulted from time to time as a result of a forced outage on a large unit. Gas storage helped SDG&E fuels traders respond to such events by providing an operational alternative for managing its balancing requirements rather than relying on trades with other market participants. The value of this operational flexibility was even more pronounced when the pipeline declared operating restrictions to force market participants to balance their gas deliveries with consumption. SDG&E's awarded storage bid was based on cost savings associated with this flexibility as well as the summer / winter price spread. As with all other fuels-related products, SDG&E complied with its LTPP in procuring gas storage capacity.

Natural gas trading and scheduling processes remained largely intact through MRTU implementation. However, the day-ahead market process increased the uncertainty of gas quantities to be traded in the day-ahead market. Prior to MRTU, day-ahead least-cost dispatch and gas trading occurred simultaneously at approximately 6:00 to 8:00 a.m., such that relatively final day-ahead generation schedules could be established through this coordinated trading process. Post-MRTU, day-ahead generation awards are not known until about 1:00 p.m., well after next-day natural gas finished trading. Because of the time lag, fuels traders had to rely on generation award forecasts and judgment to establish their next-day fuel position. When actual results deviated from forecasted fuel quantities sufficiently, fuels traders had to trade and/or schedule gas supplies in later pipeline scheduling cycles to avoid potential imbalance penalties. Activity in these later scheduling cycles typically added to the overall cost of fuel supply due to lower availability of competitive bids and offers.

VIII. LEAST COST DISPATCH PROCESS

Least cost dispatch activities were managed within SDG&E by the Electric & Fuels Department (E&FP). Key personnel involved in daily LCD activity included fuels traders and schedulers, power traders, preschedulers and real-time schedulers. The LCD process consisted of a number of parallel and sequential processes, which are described in this section.

A. <u>Weekly LCD Plan</u>

LCD began with a weekly production cost model that optimized resources to serve SDG&E's load requirement for the following 12-day period. The model software[12] was set up with numerous parameters, including load forecast, plant operating data, resource availability, market prices and dispatch constraints, which allowed the model to perform complex analysis that resulted in a preliminary forecast of generation dispatch and market transactions that minimized total variable cost to serve the forecasted load requirement.

The model produced expected utilization of resources for the planning horizon, including dispatch levels, fuel requirements and market transactions. The model output was reviewed by several sections within E&FP, including Energy Supply & Dispatch, Energy Risk Management and Settlements & Systems, to ensure that results were consistent with LCD standards.

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[12] SDG&E uses GenTrader, a leading production cost and optimization software application produced by Power Costs Inc. (PCI). GenTrader employs an optimization algorithm to calculate the optimal, constraints-bound mix of market transactions and generation from SDG&E's resource portfolio over the study period. SDG&E acquired GenTrader as part of a PCI product suite in preparation for MRTU, but was able to implement GenTrader in 2008 because it can be used as a stand-alone modeling tool that does not interact operationally with the CAISO. PCI introduced GenTrader in 1999 and continues to implement modeling and technology enhancements that SDG&E receives under its license agreement. GenTrader is used across the country in nodal and traditional markets to optimize generation portfolios. Additional product description is available at http://www.powercosts.com/products/gentrader.asp.

A detailed description of the inputs to the LCD model follows:

a. Load forecasts: Load forecasts were performed along several time frames: 12 days ahead, one day-ahead and intra-day in advance of the actual operating hour. E&FP utilized Advanced Artificial Neural-Network Short-Term Load Forecaster (AANNSTLF), a computer program developed by Pattern Recognition Technologies, Inc. for the Electric Power Research Institute (EPRI). This application analyzes relationships between historical system load and weather data, and develops an hourly load forecast. The program was updated as frequently as each hour as actual load and weather data were collected and temperature and humidity forecasts were updated by SDG&E's weather forecasting service provider[13]. SDG&E monitored the accuracy of its load forecast on an hourly basis and made corrective adjustments to its results as warranted to account for changing load patterns. SDG&E's load forecast for bundled customers served by E&FP was comprised of the SDG&E system load less transmission losses, which were calculated as a percentage estimate of the system load forecast based on historical data, less the load forecast for Direct Access customers. The Direct Access load forecast was provided twice a week by SDG&E's Load Research department. The forecast was based on the current Direct Access accounts in the SDG&E billing system and the historic load for those accounts.

b. Resource operating parameters: The model required a variety of data for each dispatchable resource to properly determine its dispatch cost. Such data included heat rates, minimum and maximum operating points, fuel delivery charges and start-up costs. Numerous operating constraints were also fed into the model including start-up time, minimum shutdown and run times and ramp rates. The model optimized the dispatch of each resource given its generation cost and operating constraints.

c. Forecast of resource availability: A significant portion of SDG&E's portfolio is comprised of must-take resources (nuclear, QF and renewable energy) and fixed-quantity transactions (DWR Bear contracts), as listed in Section V. SDG&E receives weekly, and in some cases daily, forecasts of hourly deliveries from the resource operator. SDG&E

[13] SDG&E subscribes to MDA EarthSat's weather forecasting service. MDA EarthSat is a national weather service firm that provides SDG&E with customized weather data and forecasts. Energy Supply & Dispatch personnel communicate by phone with MDA EarthSat meteorologists on a daily basis.

generates availability forecasts for some smaller contracts based on historical performance.

d. Market prices: The LCD model required a forecast of fuel prices for each of the dispatchable resources in SDG&E's portfolio, and a forecast of hourly power prices for various market delivery points. Fuel prices were based on forward natural gas price curves at SoCal Border and Opal (derived from NYMEX, ICE and broker quotes) and tariff or contract gas transportation costs. Power prices were based on forward power price curves for block power (derived from ICE and broker quotes) and shaped for each hour using price weighting factors derived from historical price and load profiles.

e. Other factors that affected the model results included congestion, hourly price weighting profile, SRAC prices for QF economic curtailments and contract or regulatory limits that imposed additional constraints on economic dispatch. Use-limited resources including certain peakers, demand response products and limited economic curtailment of the YCA contract, required a separate optimization that was performed over a longer time horizon than the 12-day LCD modeling process. These results were then fed into the model as inputs.

GenTrader then ran an optimization algorithm to calculate the hourly dispatch level of each dispatchable resource over the modeled period that was economic, or "in-the-money", relative to market prices. This determination considered up front commitment costs (start-up and minimum load costs), incremental dispatch costs which varied by output level and various operational constraints described above. For must-take resources, generation was assumed to equal their forecasted availabilities. If the sum of must-take and in-the-money dispatchable generation was less than that hour's load requirement, the short position, or Residual Net Short (RNS), was considered to be met with market purchases. If the sum of must-take and in-the-money generation was greater than that hour's load requirement, the long position was considered to be surplus generation available for economic market sales.

Two QF contracts, YCA and Goal Line, gave SDG&E limited curtailment rights when market prices were lower than the contract price for energy. Curtailment did not require these units to shut down; the QFs elected to either run and be paid the actual market price or shut down for the curtailment period. SDG&E included these curtailment provisions in its least cost dispatch and regularly monitored the difference between the market and contract prices to determine when maximum economic value could be obtained through QF curtailment.

The Goal Line QF contract allowed SDG&E to economically curtail the contract for up to five hours each day of the year. If the off-peak price for SP15 energy was lower than the QF energy price for those hours, SDG&E provided Goal Line with a daily curtailment notice, which included a curtail price.

The YCA QF contract provided for two types of economic curtailment: flexible and block. Flexible curtailments were limited to 2,200 hours per year with a minimum of 8 hours per curtailment. The block curtailments were two 200 hour blocks per year. Since these curtailments had limitations of exercise, SDG&E used forward market and contract prices to forecast when the differential between these prices would be greatest in order to maximize cost savings. SDG&E updated its YCA QF curtailment analysis monthly as the QF energy price formula uses a monthly gas price index as well as seasonal price shaping factors. In the Record Period, SDG&E used all 2,200 hours of its flexible curtailment hours during off-peak and shoulder month hours, and both 200 hour block curtailments in April 2009.

B. <u>Day-Ahead LCD Plan</u>

On a day-ahead basis by approximately 6:00 a.m., preschedulers updated the GenTrader 12-day model with updated values, specifically the load forecast, market prices and resource availabilities. Other data such as resource operating constraints are relatively static between the 12-day plan and day-ahead plan and were not typically updated. Key distinctions between the 12-day and day-ahead model parameters were as follows:

a. Load forecast: SDG&E used updated temperature and humidity forecasts from SDG&E's weather forecasting service to re-run its ANNSTLF load forecasting model. In addition, pre-schedulers applied manual adjustments to the ANNSTLF result when warranted to offset known limitations to the model. For example, because ANNSTLF forecasts are based on historical data, ANNSTLF lagged sudden changes to the weather forecast such as the onset of a heat wave. The prescheduler also benchmarked the ANNSTLF forecast to that published by the CAISO for SDG&E's service area (when available) to identify and resolve significant deviations.

b. Resource availabilities: SDG&E received updated and more accurate availability information for its resources on a day-ahead basis. These updates captured information that may not have been included in the 12-day model, such as ambient derates and forced derates and outages.

c. Market prices: Spot natural gas and power trade actively in the day-ahead market. Updated prices fed into the model reflected actual market conditions rather than a price forecast.

GenTrader then re-optimized the mix of market transactions and resource dispatches. As with the 12-day plan, GenTrader produced a plan for unit commitments, dispatch levels and economic purchases and sales.

C. <u>Day-Ahead Trading and Dispatch</u>

During the actual day-ahead least cost dispatch process, traders transitioned from the GenTrader system to customized spreadsheets to perform real-time analysis of trades and final dispatch decisions. These spreadsheets were able to better accommodate the fast-paced and dynamic nature of real-time trading and dispatch more quickly than GenTrader, which is a server-based, database-oriented software application. Traders needed the flexibility of the spreadsheets to respond to 1) volatility of market prices for both natural gas and power products during the trading session, 2) discrepancies between the modeled hourly price profile and actual hourly prices, 3) insufficient market depth / liquidity to transact for planned quantities, 4) updated positions resulting from day-ahead deals and 5) real-time updates to operational constraints such as revised unit availability and pipeline balancing requirements.

The spreadsheet tool contained the same initial values for load forecast and must-take generation as GenTrader, thereby solving for least cost dispatch of resources and market transactions to satisfy the RNS. The spreadsheet determined unit commitments that were typically consistent with those predicted by GenTrader. On occasion, traders overrode modeled unit commitments when market prices, market liquidity, operating constraints or other factors not captured in GenTrader did not support the commitment decision. For example, if low market liquidity prevented SDG&E from making sufficient surplus energy sales to support a planned commitment of the marginal unit, that unit would not have been dispatched.

Market prices are a key input into the dispatch spreadsheet. As trading activity began each morning, market price quotes from brokers and on ICE for gas and power were entered into the dispatch spreadsheet. Market prices for standard (physical or financial) peak and off-peak energy products were converted into hourly prices based weighting factors derived from historical data. The variable dispatch cost of each resource was also calculated by hour based on fuel cost and variable operating and maintenance costs. Traders were then able to directly compare generation costs to market prices in order to determine the least-cost solution.

SDG&E utilized several types of market transactions to achieve LCD. Outright purchases were made to displace higher cost generation or secure energy if the portfolio was capacity short due to unavailable resources. Outright sales were made to economically sell generation or dispose of excess must-take energy.

Exchanges are market transactions that shift supply from one period to another within the operating day. The transaction involved sending energy to a third party in one period and receiving a similar, but not necessarily equal, amount of energy from the same party in a different period of that day. These transactions allowed SDG&E to balance the shape of delivered supply to the load shape. They were traded at either a flat price (i.e., no exchange of cash) or a negotiated fee that was less than the total savings achieved via the transaction. Because market liquidity for these "odd lots" can be relatively low, exchanges were typically more efficient than separate purchase and sales, since SDG&E did not have to negotiate two separate prices with two counterparties. Exchanges also reduced the credit requirement, since the purchase and sale were made with the same counterparty on the same day.

Swaps were a third type of transaction used by SDG&E to incrementally reduce portfolio costs. Like exchanges, swaps typically did not result in a net purchase or sale of energy – a purchase at one location was offset by a sale at a different energy at a different location during the same hour. Swaps were used to avoid potential congestion charges and transmission losses, or to lock in favorable price differentials between locations. SDG&E regularly employed swaps with its Boardman contract. The Boardman contract is normally scheduled as an import at Malin to serve SDG&E load in SP15, which exposes the energy to transmission loss charges and congestion charges. When SDG&E sold this energy at Malin and repurchased the same quantity in SP26, SDG&E avoided incurring transmission loss charges and congestion risk.

SDG&E evaluated a number of factors in addition to market prices and variable generation cost to determine the benefit of market transactions, including counterparty credit, congestion risk mitigation and avoidance of unit-commitment costs such as start-up and minimum load carrying costs. SDG&E's ability to utilize market transactions to improve least cost dispatch was subject to the availability and pricing of the desired products during the least cost dispatch process. The energy transactions, executed at prices consistent with prevailing market conditions, included standard on-peak and off-peak blocks and non-standard products such as individual hour, super-peak or shoulder-hour energy. All energy trades were reported in SDG&E's Quarterly Compliance Reports and are reviewed by the Commission under the advice letters cited in Section I.

The SDG&E supply portfolio contained a number of resources capable of providing A/S (Regulation Up/Down, Spinning Reserve and Non-Spinning Reserve). The table in Section V lists these resources and their A/S capabilities. While the total A/S capacity from these resources exceeded SDG&E's bundled load requirements, the Encina and South Bay units that were capable of supplying the majority of Regulation and Spinning Reserve were [redacted] of the Record Period, therefore SDG&E purchased significant amounts of A/S from the CAISO.

Once trading and dispatch decisions were completed, preschedulers submitted trades, resource schedules and bids to the CAISO. The nature of and requirements for scheduling and bidding energy and A/S changed significantly following MRTU implementation and impacted how SDG&E's resources were dispatched. These changes are described in more detail below.

Pre-MRTU

Prior to MRTU, market participants submitted a balanced schedule to the CAISO by 10:00 a.m. the day prior to delivery. Balanced schedules exactly matched energy required for load and energy sales with generation or market purchases for each hour of the delivery day. If sufficient generation capacity in SDG&E's portfolio was in-the-money relative to market prices, SDG&E first scheduled the lowest cost generation to satisfy its load requirement. If additional in-the-money generation remained after this process, SDG&E was in a position to sell market energy if priced sufficiently above the variable cost to produce it.

Day-ahead schedules submitted to the CAISO included adjustment bids on non-SP15 resources, which protected SDG&E against interzonal and intertie congestion charges. An adjustment bid established the maximum congestion charge that SDG&E was willing to pay to schedule energy across a congested transmission path. If the congestion charge determined by the CAISO congestion management process exceeded SDG&E's adjustment bid, the CAISO reduced the SDG&E supply schedule across the congested path, thereby reducing the energy schedule for resources (including the load schedule) on both sides of the congestion. When adjustment bids were exercised in the day-ahead market, any supply schedule cuts were replaced in the hour-ahead market. When adjustment bids were exercised in the hour-ahead market, the cut supply produced a short position that carried over to the CAISO imbalance market.

Congestion charges can have a significant impact on least cost dispatch. Least cost decisions for resource dispatch or market purchases that are economic before any congestion costs are known can be rendered uneconomic once congestion charges in day-ahead or hour-ahead market are included. SDG&E submitted adjustment bids to provide the CAISO a means for modifying intertie and interzonal schedules to preserve least cost dispatch economics (SDG&E also adopted an intrazonal congestion dispatch protocol in response to D.04-07-028, which is described later in this section).

SDG&E's practice was to place adjustment bids only on schedules at CAISO interchange points, since these points were a primary source of congestion, and adjustment bids on a northern interchange point protected that schedule against congestion on Path 26. Adjustment bids were structured to reduce or zero intertie schedules if the total congestion charge at the intertie and intervening paths reached SDG&E's adjustment bid price. Adjustment bid prices were based on expected price spreads for replacement energy at uncongested locations.

Ancillary services were scheduled on resources based on two different methods. Economic bids were submitted when SDG&E elected to capture the value of opportunity cost when the capacity could otherwise be used for energy instead of A/S. Self-provision was used to directly schedule A/S on a unit if likelihood of energy dispatch was low due to high generation cost. Self-provided A/S schedules allow SDG&E to avoid that portion of the CAISO A/S charge.

With the Commission ruling in July 2004 (D.04-07-028) that utilities should include schedule deliverability and local reliability in least cost procurement decisions, SDG&E developed a procedure for determining a cost adder for transactions that could increase the potential for intrazonal congestion and a credit for generation dispatch that could reduce the potential for intrazonal congestion. These cost adders and credits were updated based on data published on the CAISO OASIS website and were incorporated into the least cost dispatch process, much like interzonal congestion costs. SDG&E's procedure to address intrazonal congestion costs was filed with the Commission on December 3, 2004 in AL 1641-E; this protocol was in effect prior to MRTU.

The CAISO Tariff required that generators that are registered as Resource Adequacy resources offer any available capacity not already scheduled for dispatch through a provision called the "must offer obligation" (MOO). Generators had to option to request a waiver from this obligation to avoid operating uneconomically in providing MOO capacity. The deadline to submit MOO waiver requests was 11 a.m. one day-ahead of delivery, which provided the CAISO enough lead time to commit long-start units for the following day. If the day-ahead least cost dispatch process did not show a need for a dispatchable resource, SDG&E submitted a must offer waiver request from the CAISO and keep the resource offline. If the CAISO denied the waiver request, the generator remained online at minimum load and the CAISO paid the generator its minimum load carrying costs. Once a generator shut down on a granted must offer waiver, the CAISO had authority to rescind the waiver at a later date if it needed the capacity to be available. On a rescinded waiver, the CAISO paid the costs for the generator to start up and operate at minimum load.

All of SDG&E's dispatchable resources were subject to dispatch by the CAISO through MOO. Under a MOO dispatch, the resource continued to remain in operation but was not part of SDG&E's schedule. The generation was instead delivered into the CAISO imbalance market. SDG&E, however, did have the option to schedule energy from the must offer resource to serve its load and assume the operating cost responsibility of the resource. SDG&E scheduled energy or A/S from a MOO dispatch resource if it was SDG&E's least cost dispatch option. When the resource was no longer scheduled against SDG&E load in the hour-ahead market, the generation defaulted back to the imbalance market.

The Calpeak peakers under the DWR contract were subject to MOO, but the DWR contract specified that the plants' Scheduling Coordinator manage the MOO requirements. In October 2004, through Amendment 60 to its Tariff, the CAISO made significant changes to the must-offer process. Amendment 60 accelerated the timeline for CAISO notification of waiver denial and removed the exclusion of minimum load cost recovery when A/S schedules were placed on a unit operating on a denied waiver. Under the new process, the CAISO responded to the waiver request while the interim day-ahead market was open, allowing a day-ahead A/S schedule to be put on a resource in the interim market if waivers were denied.

Post-MRTU

MRTU replaced the day-ahead scheduling process with a day-ahead market (DAM) to economically clear load and resources that were scheduled or bid. As described in Section IV, the DAM resulted in significant changes to day-ahead least-cost dispatch. The day-ahead balancing requirement was eliminated and replaced with separate schedules and bids for each resource and load. Results of the DAM became financially binding at the market clearing price for each resource and load, and the sum of SDG&E's cleared resources did not necessarily balance with SDG&E's load award. Scheduling of load and (non-wind) must-take resources remained substantively unchanged from pre-MRTU scheduling. For wind and dispatchable resources, SDG&E developed new scheduling and bidding protocols that differed substantially from pre-MRTU practice, as discussed below.

- Load: As noted, Amendment 72 requiring LSEs to schedule at least 95% of the load forecast (and 75% during off-peak hours) expired upon MRTU launch, which introduced more flexibility in the way SDG&E could schedule or bid its load obligation in the day-ahead market. SDG&E chose to adopt a risk-mitigating strategy by self-scheduling load to within [redacted] of the day-ahead forecast during on-peak hours, and within [redacted] during off-peak hours. Self-scheduling ensured that SDG&E would purchase nearly its entire load requirement in the day-ahead market rather than rolling the requirement into the real-time market. The day-ahead market was preferred for several reasons. The first is that the overall market cleared most of its load and resources in the day-ahead market; this market depth helped ensure that clearing prices reflect competitive supply bids. The second reason was that SDG&E also scheduled or bid most of its resources into the day-ahead market. Therefore, while balanced schedules were not strictly required, day-ahead supply quantities that cleared effectively offset the day-ahead costs assessed to the cleared load quantity. The third reason for clearing load in the DAM was to avoid a CAISO-assessed underscheduling charge. With certain exceptions, 85% of actual (metered) load must clear in the DAM. If the DAM award is less than 85%, the shortfall quantity (85% of actual load minus the DAM award) is assessed the underscheduling charge which ranges from $150 to $250/MWh depending on the shortfall quantity.
- Non-wind must-take resources: Scheduling of non-wind must-take generation was largely unaffected by MRTU. SDG&E continued to self-schedule available must-take

generation on a day-ahead basis to offset DAM load awards. For resources that were scheduled by sellers and not SDG&E, sellers continued to self-schedule their available generation into the DAM. Credit for the DA revenues was transferred back to SDG&E either via an Inter-SC Trade (IST) for the self-scheduled quantity, or settled after the fact by the settlements group.

- Wind generation: All SDG&E wind resources were scheduled by sellers, and they all continued to participate in the Participating Intermittent Resource Program (PIRP) after MRTU implementation. PIRP requires that participating resources schedule the final generation forecast published by PIRP in the Hour-Ahead Scheduling Process (HASP). Prior to MRTU, sellers agreed to schedule the forecasted PIRP quantity to SDG&E as a day-ahead SC-SC trade. As PIRP issued the final hour-ahead forecast each hour, SDG&E and the seller simply revised the SC-SC quantity to match this value in time to meet the hour-ahead scheduling deadline. MRTU complicated this process due to the introduction of financially binding obligations on day-ahead generation schedules, and caused sellers to stop scheduling wind generation in the day-ahead market. The result is that under MRTU all sellers began scheduling wind generation only in the HASP. The CAISO pays the real-time market clearing price for such schedules, rather than the day-ahead market clearing price.
- Dispatchable resources: All dispatchable resources in SDG&E's portfolio were Resource Adequacy resources; therefore SDG&E (or Sellers' Scheduling Coordinator) had an obligation to offer these resources into the day-ahead market and could not charge the CAISO for Residual Unit Commitment (RUC) capacity awards. SDG&E's primary objective with respect to schedules and bids for dispatchable resources was to maintain adherence to least-cost dispatch principles. This objective was met through two strategies – bidding generation into the DAM at costs consistent with the LCD modeling, or self-scheduling resources that LCD modeling forecasted to clear the DAM economically.

While self-schedules were not mandatory, they did provide certainty to fuels traders as to the minimum natural gas quantity that resources would consume. This was particularly useful for the Sunrise plant because it has limited gas balancing rights on its pipeline. A second benefit was that self-scheduled generation quantities mitigated charges for bid-cost recovery assessed to SDG&E's load.

As noted, SDG&E submitted day-ahead generation bids that reflected actual operating costs used in LCD modeling. However, MRTU bidding rules imposed some constraints on this process. Supply bids have three basic components: startup cost, minimum load cost and incremental energy bids. Startup and minimum load costs used in the day-ahead market were actually created by CAISO software that relied in part on a proxy gas price comprised of published price indexes. The proxy gas price lags the actual traded gas price by one or more days, which may have caused deviations from the day-ahead LCD solution that SDG&E traders established through lock-step trading of power and natural gas. Also, bidding rules require that incremental energy bids be monotonically increasing over the range of output. This rule contradicted the actual incremental energy cost of combined cycle plants because the true incremental cost decreases as well as increases as they transition through operating modes to ramp from minimum to maximum load. Therefore SDG&E had to develop modified energy bid curves for Palomar, Sunrise and Otay Mesa that complied with the monotonically increasing bid rule. SDG&E performs post-market assessments to confirm that these modified bid curves did not result in uneconomic day-ahead awards.

Another component of the supply bid that pertained to A/S-certified units is bids for Regulation, Spinning Reserve and Non-Spinning Reserve. As discussed in Section IV, the day-ahead market algorithm co-optimizes dispatchable capacity between generation and A/S awards; the generator is paid at least its opportunity cost of forgoing a profitable day-ahead energy sale. However, co-optimization does not consider lost energy sales in the real-time market (capacity awarded A/S for Spinning and Non-Spinning Reserves is typically not released for dispatch in the real-time market). Therefore SDG&E incorporates an estimate of expected real-time profit in A/S bid for units that typically participate in that market.

Another feature of supply bids post-MRTU is the absence of adjustment bids. Pre-MRTU, SDG&E submitted adjustment bids for resources originating from a different zone or intertie point than SDG&E's load to limit congestion costs incurred. Under MRTU, adjustment bids were not used because the locational marginal price (LMP) is included a congestion cost component at each delivery point in the system. Congestion reduced the LMP and resulted in a lower day-ahead award if the congested price was lower than the generation bid. While

SDG&E's resources were prone to some congestion charges, these charges were significantly offset by revenues from Congestion Revenue Rights (CRRs) that SDG&E acquired to hedge this risk, as described in Section X.

D. Hour-Ahead Least Cost Dispatch

After the CAISO published final day-ahead schedules, least-cost dispatch of the portfolio was transferred to SDG&E's real-time desk, which is staffed around the clock. The real-time desk was responsible for maintaining least-cost dispatch of the portfolio, within scheduling and operational constraints, in response to intraday events that affected the portfolio position. The real-time desk primarily relied on hour-ahead energy trades and modifying generation self-schedules and bids to carry out LCD before the hour-ahead scheduling deadline[14]. If no viable option was available due to lack of market liquidity or lack of incremental generation capacity, the exposure was transferred to the real-time energy market where the CAISO incrementally dispatched units on the system to offset SDG&E's position. Most hour-ahead LCD activity was triggered by four types of events: 1) change in load forecast, 2) derate or outage affecting a day-ahead resource schedule, 3) revised wind generation forecast and 4) market price changes.

- Change in load forecast: The real-time desk used ANNSTLF to update the load forecast intraday. Actual hourly loads and weather data were entered into ANNSTLF as the day progressed, which enabled the model to produce a more accurate load forecast for the balance of the day. An increase in load forecast created a short position in the real-time market, other things being equal, and a decrease in load forecast created a long real-time position. Given a particular load forecast change, the real-time desk took action to mitigate the exposure with intraday market trades and self-schedules or relied on generation to be dispatched economically in the real-time market to cover the load position.
- Derate or outage: Forced derates and outages prevented SDG&E's resources from meeting day-ahead generation schedules and created a short position in the portfolio. The suddenness of forced derates and outages events prevented SDG&E from offsetting the short position in the first two to three hours due to the hour-ahead scheduling deadline to submit trades or revised generation schedules. If the duration

[14] The hour-ahead scheduling deadline was 2 hours before the delivery hour under the pre-MRTU market, and 75 minutes before the delivery hour under MRTU.

of the derate or outage extended beyond the scheduling deadline, SDG&E mitigated the exposure with market purchases or incremental generation to the extent available.

- Revised wind generation forecast: SDG&E has six wind generation PPAs in its portfolio, including two allocated DWR wind generation PPAs. Each of these contracts participated in PIRP. An element of the PIRP is that each participating wind generator schedules the generation that is forecasted by the CAISO in the hour-ahead scheduling process. A change in the final PIRP forecast therefore had a corresponding effect on SDG&E's real-time position. If no viable option was available due to lack of market liquidity or incremental / decremental generation, the exposure was transferred to the real-time energy market.
- Market prices: An integral part of LCD is the trading of energy in order to reduce customer cost. SDG&E made hour-ahead market purchases if priced below the incremental cost of scheduled generation, and hour-ahead market sales if priced above the incremental cost of surplus generation capacity.

The real-time desk used a spreadsheet tool populated with day-ahead energy and A/S schedules to establish the starting point for hour-ahead least cost dispatch. The spreadsheet was then updated as events occurred to calculate an up-to-date net long or short position for each hour. Based on the cost of delivered gas, heat rate and load point for each dispatchable resource, the spreadsheet indicated the incremental (or decremental) cost of changing the output of any dispatchable capacity. The real time desk compared hour-ahead market prices with dispatchable resource costs to determine the least cost solution for balancing load in the hour-ahead market.

Once trading and dispatch decisions were completed, the real-time desk submitted trades, resource schedules and bids to the CAISO. Scheduling and bidding requirements changed with MRTU, and impacted SDG&E's hour-ahead protocols. These changes are described in more detail below.

<u>Pre-MRTU</u>

Before the hour-ahead scheduling deadline, SDG&E submitted final hour-ahead schedules to the CAISO to balance resources against the final load schedule. The resources represented the least-cost mix of generation and market transactions to meet load requirements. These schedules often differed somewhat from day-ahead schedules to account for revised forecasts and resource availabilities and new hour-ahead trades. However, like day-ahead schedules, the quantity of each hour-ahead resource schedule represented the full amount of energy that the resource was scheduled to deliver, not an incremental amount. This element of hour-ahead scheduling changed under MRTU.

Prior to MRTU, SDG&E was a relatively active participant in the hour-ahead market. Market liquidity was often sufficient to allow SDG&E to reduce portfolio cost by purchasing energy below the cost of the marginal unit or selling energy above the cost of the marginal unit. Trades were typically done at SP26 to avoid congestion risk; however, some hour-ahead intertie energy was purchased when favorably priced, requiring submission of hour-ahead schedules, adjustment bids and e-tags. SDG&E also submitted cost-based supplemental energy bids for Palomar, Miramar 1 and 2 and the Encina units. Supplemental energy bids for South Bay were submitted by Dynegy (South Bay's scheduling coordinator) at SDG&E's direction. No supplemental energy bids were submitted for Calpeak peakers prior to MRTU, as real-time dispatch was outside the scope of the DWR-Calpeak PPA. [redacted] were submitted for the Sunrise unit; the CAISO [redacted] the limited balancing capability of Kern River Gas Transportation, the pipeline that serves the plant. The pipeline tariff limits daily gas imbalances to 2% of total deliveries. Supplemental (or real-time) energy bidding remained relatively intact from a process standpoint under MRTU, with some modifications as described below.

<u>Post-MRTU</u>

A significant change under MRTU affecting hour-ahead LCD was the creation of the HASP market at intertie points. Like the day-ahead market, the HASP market established financially binding awards for hour-ahead self-schedules and awarded bids, but only at intertie scheduling points. The HASP market enabled SDG&E to submit cost-based bids for the Boardman import so that the day-ahead award could be economically decremented. Essentially, SDG&E would buy back the day-ahead delivery obligation if the HASP price, which can deviate significantly from the day-ahead price, dropped below SDG&E's cost. No HASP market was implemented for resources or load within the CAISO system; the CAISO published advisory HASP prices and awards for these resources and loads but they were not financially binding.

As noted earlier, under MRTU the day-ahead market produced financially binding awards for all cleared load and supply at the day-ahead LMPs. This in some ways simplified hour-ahead scheduling because all hour-ahead changes became incremental or decremental to the day-ahead awarded quantity. For example, if the day-ahead market cleared 3,000 MW of load but the hour-ahead load forecast was for 3,100 MW, the hour-ahead LCD response was limited to only the incremental 100 MW load because the first 3,000 MW had already been purchased at the day-ahead price. Likewise, if a unit was awarded 200 MW day-ahead but its self-schedule was revised upward to 250 MW, only the incremental 50 MW would be sold in the real-time market since the first 200 MW had already been claimed day-ahead. In either case, incremental or decremental quantities of load or supply were settled at the real-time price, which the CAISO published for each 5-minute interval at each price node.

Another difference affecting hour-ahead LCD was the use of self-schedules on SDG&E's resources. Self-schedules are essentially price-taker bids submitted into the day-ahead or real-time market. The CAISO used generator self-schedules to establish a floor on the unit's dispatch awards in the real-time market. Therefore, hour-ahead self-schedules, if greater than the day-ahead award, caused the incremental portion to be a price-taker at the real-time price. This rule also applied to PIRP wind self-schedules that were submitted hour-ahead. Of note, under MRTU the CAISO does not accept hour-ahead self-schedules for load, since incremental or decremental (firm) load is a price taker in any event.

In response to these new market rules, SDG&E modified its hour-ahead scheduling processes to comply with LCD principles. As describe earlier, SDG&E began to submit bids into the HASP market for its Boardman import to allow for the buy-back of its day-ahead award if economic. SDG&E's also self-scheduled its dispatchable generation committed in the day-ahead market at the minimum dispatch level, which enabled the CAISO to decrement the unit in response to low real-time prices. This strategy was modified as needed, for example to set a higher level of real-time dispatch to offset higher load requirement, or to mitigate excessive cycling of the units due to volatile real-time market prices.

Before MRTU, SDG&E relied primarily on hour-ahead trades or adjustments to resource schedules to balance its portfolio. The new hour-ahead scheduling rules, in conjunction with the steep decline in trading liquidity post-MRTU, shifted the focus of the real-time desk to providing the CAISO with appropriate hour-ahead self-schedules and energy bids such that SDG&E's resources were dispatched in a LCD manner in the real-time market.

IX. CONSTRAINTS TO LEAST COST DISPATCH

As stated in the discussion of LCD principles, SDG&E performed its least cost dispatch activities within limits established by numerous types of constraints that range from operational, regulatory and contractual to risk mitigation and market conditions. An after-the-fact review of a particular day's dispatch may show a deviation from LCD because of the effects of such constraints.

Some constraints were operating limits inherent to the resources in the portfolio. For example, generators cannot cycle back and forth between online and offline because of minimum run time and shutdown time of each combustion turbine. Therefore, the lowest cost unit may not be dispatched if sufficient time for startup is not available. Or, surplus energy may be sold below variable generation cost if SDG&E is long energy and has no resources that can be cycled off. Some other common examples of LCD constraints include the following:

- Exceptional Dispatch (ED) is a form of dispatch under MRTU the CAISO relies on to meet reliability requirements that cannot be resolved through market processes. The CAISO orders EDs to address local generation requirements, system capacity needs, transmission outages, software limitations and other operational issues. Because EDs are reliability-driven, they are outside the scope of LCD and likely to be uneconomic relative to market prices or other resources. However, all SDG&E resources were obligated to comply with these dispatches.
- Residual Unit Commitment (RUC) is a market award for capacity the CAISO issues to ensure that sufficient capacity is committed to meet system load. Although RUC resulted from the market process, it is required to manage grid reliability and is outside the scope of LCD. SDG&E resources were obligated to be available to provide the RUC capacity if awarded, which required that they be committed uneconomically relative to market prices.
- Unit testing and maintenance, such as RATA tests and heat treats, require generators to run at pre-defined load points to achieve an objective. During these periods, generation is considered must take and cannot be dispatched according to LCD economics.
- Constrained pipeline operations may impact least cost dispatch. As noted, Sunrise could not respond to the real-time LCD requirement because of limited gas balancing

rights on the Kern River pipeline. Another example of pipeline constraints was Operational Flow Orders (OFOs) declared by SoCal Gas. Under an OFO, if a resource failed to consume 90% of the scheduled natural gas quantity, the pipeline assessed penalties. Therefore resources were constrained from following real-time LCD dispatches to decrease generation.

- Use-limited resources are resources that are only available for a limited number of hours per period. To efficiently allocate dispatches on these units, SDG&E planned their use over a monthly or annual time horizon depending on the limit. For example, annual environmental restrictions limit the number of startups on the Encina combustion turbine. SDG&E managed its use so that it would be available over summer peak load periods. Therefore, a hindsight review will show that this unit was not dispatched according to LCD during other periods. Other resources that were use-limited include Demand Response programs that can be triggered for limited hours each month and the YCA and Goal Line QF contracts that allowed for economic curtailment for limited hours per day and per year.
- Market liquidity can be described as the amount of energy that can be traded at a particular price. Low market liquidity can prevent SDG&E from executing transactions to achieve anticipated least cost dispatch. Liquidity was not only a result of general market conditions such as price volatility or disinterest by the market, but also limited by counterparties that SDG&E traders were approved to trade with given authorized credit limits.

X. FIRM TRANSMISSION RIGHTS / CONGESTION REVENUE RIGHTS

During the Record Period, prior to MRTU, SDG&E used Firm Transmission Rights (FTRs) to offset interzonal congestion charges resulting from scheduling non-SP26 resources against SDG&E's load (located entirely in SP26) in the day-ahead market. For this time period, SDG&E acquired 560 MWs of Path 26 FTR capacity to hedge Sunrise schedules.

The Sunrise resource created the highest need for FTRs because it is SDG&E's largest resource outside SP26 and is typically scheduled at high load points because of its efficient heat rate. To serve SDG&E load, energy from Sunrise must be scheduled across Path 26, which has been observed to be a congested path. Boardman energy delivery is also subject to congestion charges because it is scheduled across the Malin-NP15 path in addition to Path 26. Boardman is a coal-fired plant that produces energy at a low variable cost; therefore SDG&E typically accepts its contracted share each day. SDG&E has the option to sell Boardman energy back to the market at Malin and avoid congestion risk; therefore SDG&E can be more selective with its Malin FTR bid than the Path 26 FTR bid, as market liquidity at ZP26 is generally insufficient to sell the entire output of Sunrise there on a day-ahead basis.

SDG&E established the maximum price to bid for FTRs by forecasting the likelihood of congestion charges and assessing the cost to re-dispatch units in the event congestion charges made Sunrise and Boardman energy uneconomic to schedule, relative to other options in SDG&E portfolio.

SDG&E acquired its Q1 2009 FTRs in the auction process administered by the CAISO in 2008. The auction was run March 11-13, 2008 to competitively allocate FTR capacity from April 1, 2008 through March 31, 2009. In addition, SDG&E acquired Q2 – Q4 2009 FTRs through the auction process administered by the CAISO in 2009. The auction was run January 27-29, 2009 to competitively allocate FTR capacity from April 1, 2009 through March 31, 2010. However, these FTRs never became active as their terms were subject to expire upon MRTU launch, which did in fact occur on April 1, 2009.

Upon implementation of MRTU, the CAISO introduced a new product called Congestion Revenue Rights (CRRs), which provides CRR holders a hedge against day-ahead congestion differentials across two price nodes, typically from a generation delivery point to a load receipt point. The CAISO determines congestion based on the Full Network Model. Contrary to FTRs that paid the FTR holder the price difference between the receipt point minus the delivery point only when positive, CRRs paid the CRR holder the positive *or negative* difference. Therefore, ownership of CRRs entailed risk of losses if actual congestion was opposite to that which was expected at the time the CRR was acquired. The CAISO began its initial auction for yearly CRR awards in the fall of 2007 in anticipation of an MRTU launch date of April 1, 2008. In this annual allocation process, the CAISO issued CRRs for Q2, Q3 and Q4 of 2008 but none of these CRRs became effective due to the MRTU delays. The CAISO ran its 2009 annual allocation process in the fall of 2008, using "Year 1" CRR rules for Q1 and "Year 2" rules for Q2, Q3 and Q4. "Year 1" CRR rules limit Tier 1 and 2 nominations to verified sources with open nominations in Tier 3. "Year 2" rules limit Tier 1 nominations to renewal of prior year CRRs with open nominations in Tiers 2 and 3. SDG&E's strategy for both sets of CRR rules was to nominate in the early rounds those resources in its portfolio forecast to be at higher congestion risk and shift nominations to lower congestion risk resources in the later rounds. The determination of portfolio congestion risk was made using the results from power flow analysis of the CAISO grid for 2009, performed by SDG&E Transmission Planning.

During the 2008 annual CRR process, SDG&E elected to convert some of its awarded CRRs to Long Term CRRs, which have a 10-year term. SDG&E limited long term CRR conversion to its YCA resource, since its contract has longer than a 10 year remaining term and it has a high congestion risk. The YCA CRRs were part of SDG&E CRR portfolio in 2009. SDG&E was also awarded YCA CRRs for Q1 of 2009 and likewise converted them to Long Term CRRs. Small quantities of YCA CRRs were also acquired in Q2, Q3, and Q4 2009, and they too were converted to Long Term CRRs.

Following the 2009 annual allocation process, the CAISO conducted the 2009 annual auction process, which is open to all market participants (unlike the allocation process which is just open to LSEs). SDG&E did not participate in the 2009 annual auction process because CRRs for the remaining resources that SDG&E sought to hedge were unavailable as a result of earlier allocation processes.

SDG&E was able to supplement CRRs awarded in the annual allocation process through the monthly CRR process. SDG&E's strategy in the monthly CRR process was much the same as the annual allocation, to nominate high congestion risk resources first followed by lesser congestion risk resources. The nomination quantity was based on the difference between expected requirements for a resource less its CRR quantity from the annual allocation. The monthly CRR process also included an auction segment, following the allocation segment. As with the annual auction, SDG&E seldom participated in the monthly auction due to the risk of incurring negative congestion charges. SDG&E did bid into the October monthly auction to support a new contract, but did not receive an award.

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XI. MRTU-RELATED COSTS

This chapter addresses costs incurred from 2007 through 2009, incremental to those established in the 2008 General Rate Case (GRC)[15], to enable SDG&E to prepare for and participate in the CAISO market post-MRTU. The implementation of MRTU resulted in significantly more complex utility operations than required in the pre-MRTU CAISO structure. The CAISO introduced several core operating systems, including Scheduling Infrastructure Business Rules (SIBR), California ISO Market Results Interface (CMRI) and an updated interface for Open Access Same-Time Information System (OASIS), each requiring new and more complex data sets and interface protocols. In order to adapt its operations to meet these new requirements, SDG&E incurred capital and O&M costs totaling $4,616,581 from 2007 through 2009, primarily for software-related items and incremental direct labor.

The MRTU Memorandum Account (MRTUMA) was established under Commission Resolution E-4088 dated May 24, 2007, pursuant to SDG&E Advice Letter 1867-E to record and recover Commission-authorized costs that are incremental to approved items authorized under the effective GRC revenue requirements. As of 12/31/2009, SDG&E recorded a portion of its 2007 through 2009 MRTU-related costs ($2,581,192) in the MRTUMA, as presented in Ms. Le Mieux's testimony. SDG&E continues to record additional costs associated with MRTU requirements, including ongoing costs to comply with FERC-mandated enhancements such as the Markets and Performance (MAP) initiative, to the MRTUMA until these costs can be captured in the next GRC. The next GRC for SDG&E is 2012.

The Commission reaffirmed the scope of review for the MRTUMA prescribed in Resolution E-4087 in its final decision in Pacific Gas & Electric Company's June 18 2009 ERRA Forecast proceeding (A.09-06-001). Decision 09-12-021 states: "[T]he Commission notes that the scope of its review of PG&E's MRTU costs is not necessarily a traditional reasonableness review. The MRTU project is a project mandated by regulatory and reliability requirements of the California Independent System Operator and Federal Energy Regulatory Commission. Therefore, the Commission expects the review of these costs to primarily focus on whether the costs can be verified and are incremental."

[15] In the 2008 GRC, SDG&E requested and was authorized 2 additional FTEs for MRTU requirements.

Tables 1 and 2 summarize SDG&E's MRTU-related costs from 2007 through 2009. SDG&E is seeking recovery for a total of $1.571 MM in O&M expenses plus $3.046 MM in capital costs for inclusion in the rate base.

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Table 1: Capital Costs

2007-2009 MRTU Capital Summary		2007		2008		2009		Grand Total
AFUDC Settlement	$	41,356	$	30,166	$	45,623	$	117,145
Computer Hardware	$	314,621	$	(268,000)			$	46,621
Contractor/Consultant	$	674,283	$	477,962	$	152,868	$	1,305,113
Labor	$	97,658	$	67,568	$	12,095	$	177,321
Overhead	$	83,196	$	51,679	$	12,560	$	147,436
Software	$	475,169	$	436,306	$	340,560	$	1,252,035
Grand Total	**$**	**1,686,284**	**$**	**795,681**	**$**	**563,706**	**$**	**3,045,671**

The largest categories of capital costs were Software ($1.252 MM) and capitalized Contractor/Consultant ($1.305 MM), which represented about 84% of total capital. The primary MRTU software cost was the purchase of the GenBase / GenPortal / GenTrader / GenManager product suite from Power Costs Inc. (PCI). Software purchased from Allegro and BEA Systems Inc. also contributed to capitalized software cost. The functionality of these software purchases are described below.

- GenBase is a PCI-developed database that stores market price data, market awards, resource configuration, market bids, calculated values and other information required to operate under the MRTU environment. GenBase is the primary database for all PCI applications.
- GenPortal is the module used to create and manage workflows. It works in tandem with GenBase and GenManager to perform data calculation and processing tasks.
- GenTrader is a production cost and optimization software application produced by PCI. GenTrader employs an optimization algorithm to calculate the optimal, constraints-bound mix of market transactions and generation from SDG&E's resource portfolio over the study period. SDG&E acquired GenTrader as part of a PCI product suite in preparation for MRTU, but was able to implement GenTrader in 2008 because it can be used as a stand-alone modeling tool that does not interact operationally with the CAISO.

- GenManager contains the functionality to prepare complex bid files and submit them to the CAISO. It communicates with CAISO systems to validate bid status.
- The Allegro software replaced SDG&E's existing system of record for market transactions (ACES) in 2009. MRTU-related cost (incremental to that funded under the GRC) was incurred to purchase additional software (Power Module) from Allegro. The Power Module provides users with a single repository for physical and financial power trades and positions, and provides traders, credit managers, risk managers, and accountants with instant access to data.
- The BEA Systems charge was for WebLogic server software required to run the PCI application.

Capitalized Contractor/Consultant costs were incurred for software implementation work performed by PCI and Allegro.

- The PCI product suite is used in several markets across the United States and needed to be customized to meet SDG&E and CAISO requirements. PCI performed much of this work including modeling and configuring each of SDG&E's resources, ensuring that all bid and schedule calculations complied with MRTU market rules, designing / creating user interfaces and testing CAISO communication protocols. Additional costs were incurred to adapt to CASIO's frequent requirements modifications during the Market simulation phases.
- The Allegro amount reflects work performed by the vendor to specify, design, deliver and test the software.

Other categories of MRTU-related capitalized costs are described below:

- Capitalized Labor costs reflect IT work in the following areas: definition of MRTU business process and systems requirements, assessment and selection of vendors and products, development and integration of systems (for example, building an interface between PCI and Allegro to transfer transaction data), and product testing.
- Overhead costs reflect applicable labor and non-labor overheads to the costs charged as capital.
- Computer Hardware costs were incurred to procure and implement application servers used to host MRTU application software in production, QA, and Disaster Recovery environments.

- Allowance for Funds Used During Construction (AFUDC) represents the cost of borrowing funds until a project is placed into operation.

Table 2: O&M Expenses

2007-2009 MRTU O&M Summary	2007	2008	2009	Grand Total
Contractor/Consultant	$ 128,615	$ 1,800	$ 426,601	$ 557,016
Employee Travel	$ 1,169	$ 18,581	$ 10,379	$ 30,129
Labor		$ 168,557	$ 234,114	$ 402,671
Other		$ 8,023	$ 1,985	$ 10,008
Overhead		$ 38,349	$ 55,772	$ 94,121
Software		$ 13,058	$ 440,405	$ 453,463
Training		$ 22,206	$ 1,295	$ 23,501
Grand Total	**$ 129,784**	**$ 270,575**	**$ 1,170,551**	**$ 1,570,910**

The largest categories of O&M expenses were Contractor/Consultant ($557K), Software ($453K) and Labor ($403K). These represented about 90% of total O&M costs and are described below.

- PCI performed post-installation work in the following areas: bid strategy implementation, installation and setup of Bid Evaluator module, configuration of resources (e.g. new resources, refinement to existing configurations, application to Outage Management module), automation of certain workflows, creation of customized dashboards (user interfaces), response to MRTU enhancements including A/S HASP and Proxy Demand Resource.
- Allegro performed post-installation work to customize their software to meet SDG&E-specific requirements related to data table configuration and communication with PCI and CAISO interfaces.
- Business Development Strategies performed quantitative analysis of market data and SDG&E's portfolio and recommended alternative bidding strategies.
- Customized Energy Solutions performed detailed analysis of CAISO MRTU settlement statements to validate revenues and charges.
- Software costs primarily reflect annual license fees and maintenance costs paid to Allegro and PCI for software upgrades and product support from the software vendors. These

charges began to accrue once the software products were delivered and placed into production in 2009.

- Labor costs reflect 1 to 4 FTEs (depending on year) who performed the following MRTU-related work:
    - Project management, resource coordination
    - Participation in MRTU stakeholder processes
    - PCI configuration and acceptance testing
    - Training and procedures development
    - Market simulation
    - Strategy development
    - CRR valuation, strategy, bidding, portfolio management
    - Market data analysis, report generation
    - Settlement support, predictive reports
    - Scheduling support
    - Integration of new initiatives, e.g. MAP

Other categories of MRTU-related O&M expenses are described below:

- Overhead costs reflect applicable labor and non-labor overheads to the costs charged as O&M.
- Employee Travel costs primarily reflects travel costs to/from the CAISO offices by various SDG&E personnel from 2007 through 2009 to participate in MRTU workshops, implementation / market simulation meetings.
- Training costs reflect MRTU training provided to SDG&E personnel by EUCI and PCI.

XII. CONCLUSION

SDG&E described its plans for serving load from its fully integrated portfolio of utility-owned resources, power purchase contracts, allocated DWR contracts and market transactions in the Commission-approved LTPP in effect for the Record Period. SDG&E managed the operational, dispatch and administrative functions of the allocated DWR contracts and prudently dispatched those contracts, along with its resources from its own portfolio, in a least cost manner during the Record Period. SDG&E consistently followed the Commission's directive to make dispatch decisions based on variable costs. As a result, all costs recorded to SDG&E's 2009 ERRA should be fully eligible for cost recovery through rates.

SDG&E also requests the Commission find all MRTU-related costs, in the amount of $4,616,581, in compliance with SDG&E's approved MRTUMA tariff and grant the authority to transfer the December 31, 2009 balance in the MRTUMA of $2,581,192 to the NGBA for future recovery in SDG&E's electric commodity rates in accordance with the approved disposition of the account.

This concludes my prepared direct testimony.

XIII. QUALIFICATIONS

My name is Tony Choi. My business address is 8315 Century Park Court, San Diego, CA 92123. I am currently employed by SDG&E as Market Operations Manager. My responsibilities include overseeing a staff of schedulers involved in dispatching the SDG&E bundled load portfolio of supply assets for the benefit of retail electric customers. This includes operational administration of DWR contracts, transacting in the real-time wholesale market and managing scheduling activities in compliance with CAISO requirements. I assumed my current position in March 2007.

I previously managed the Electric Power and Generation Fuels Trading desks for SDG&E, primarily managing day-ahead and forward procurement of energy. Prior to joining SDG&E in 2002, my experience included two years as a power plant engineer, four years as an energy trader and three years as a wholesale energy transaction structurer.

I hold a Bachelors degree in Chemical Engineering and a Masters degree in Business Administration from the University of California, Berkeley. I have previously testified before the CPUC.

APPENDIX 1

[redacted]

[redacted]

[redacted]

**BEFORE THE PUBLIC UTILITIES
COMMISSION OF THE STATE OF CALIFORNIA**

**DECLARATION
OF TONY CHOI**

A.10-06-XXX

Application of San Diego Gas & Electric Company (U 902-E) for Approval of: (i) Contract Administration, Least Cost Dispatch and Power Procurement Activities, and (ii) Costs Related to those Activities Recorded to the Energy Resource Recovery Account, Incurred During the Record Period January 1, 2009 through December 31, 2009, and (iii) the Entries Recorded in Related Regulatory Accounts.

I, Tony Choi, do declare as follows:

1. I am the Market Operations Manager for San Diego Gas & Electric Company ("SDG&E"). I have included my Direct Testimony ("Testimony") in support of SDG&E's Application for Approval of: (i) Contract Administration, Least Cost Dispatch and Power Procurement Activities, and (ii) Costs Related to those Activities Recorded to the Energy Resource Recovery Account, incurred during the Record Period January 1, 2009 through December 31, 2009, and (iii) the Entries Recorded in Related Regulatory Accounts. Additionally, as Market Operations Manager, I am thoroughly familiar with the facts and representations in this declaration and if called upon to testify I could and would testify to the following based upon personal knowledge.

2. I am providing this Declaration to demonstrate that the confidential information ("Protected Information") in support of the referenced Application falls within the scope of data provided confidential treatment in the IOU Matrix ("Matrix") attached to the Commission's Decision D.06-06-066 (the Phase I Confidentiality decision). Pursuant to the procedure set forth in the August 22, 2006 Ruling of ALJ

Thomas, I am addressing each of the following five features of Ordering Paragraph 2 in D.06-06-066:

- that the material constitutes a particular type of data listed in the Matrix;
- the category or categories in the Matrix the data correspond to;
- that SDG&E is complying with the limitations on confidentiality specified in the Matrix for that type of data;
- that the information is not already public; and
- that the data cannot be aggregated, redacted, summarized, masked or otherwise protected in a way that allows partial disclosure.

3. The confidential information contained in my Testimony constitutes material, market sensitive, electric procurement-related information that is within the scope of Section 454.5(g) of the Public Utilities Code.[1] As such, the Protected Information provided by SDGE is allowed confidential treatment in accordance with Appendix 1 – IOU Matrix in D.06-06-066.

Confidential Information	**Matrix Reference**	**Reason for Confidentiality**
Lines 8-11 on page TC-9	VI.B	Utility Bundled Net Open (Long or Short) Position for Energy. Confidential for one year.
Line 3 on page TC-11	I.B.2	Covers actual quantity of procured natural gas transportation. Confidential for one year.
Line 18 on page TC-18	VI.B	Utility Bundled Net Open (Long or Short) Position for Energy. Confidential for one year.
Line 19 on page TC-21	VI.B	Utility Bundled Net Open (Long or Short) Position for Energy. Confidential for one year.
Lines 16-18 on page TC-26	VI.B	Utility Bundled Net Open (Long or Short) Position for Energy. Confidential for one year.
Tables in Appendix I	VI.B	Utility Bundled Net Open (Long or Short) Position for Energy. Confidential for one year.

[1] In addition to the details addressed herein, SDG&E believes that the information being furnished in my Testimony is governed by Public Utilities Code Section 583 and General Order 66-C. Accordingly, SDG&E seeks confidential treatment of such data under those provisions, as applicable.

4. I am not aware of any instances where the Protected Information has been disclosed to the public. To my knowledge, no party, including SDG&E, has publicly revealed any of the Protected Information.

5. I will comply with the limitations on confidentiality specified in the Matrix for the type of data that is provided herewith.

6. The Protected Information cannot be provided in a form that is aggregated, partially redacted, or summarized and continue to provide the level of support to the Application as intended; however SDG&E is certainly willing to work with the Commission regarding possible aggregations if the Commission seeks to make any of the confidential information provided in the Testimony public.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 1st day of June, 2010, at San Diego, California.

Tony Choi
Market Operations Manager
San Diego Gas & Electric Company