REFORMING CALIFORNIA'S DEMAND RESERVES PARTNERSHIP

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ABSTRACT

California's Demand Reserves Partnership (DRP) is one of several demand response programs offered to end-use customers. The DRP is significant because it is the only state-wide demand response program and the only one in which California's State Water Project, with 200 MW of energy, participates. However, when the DRP was implemented in July 2002, the program did not perform as expected. Utilities initiated demand response events when electricity reached a trigger price, and as natural gas prices soared, demand response events were called almost daily, putting considerable and unexpected strain on demand response participants—the DRP had become a mandatory price response program. Since October 2005, EnerNOC and other demand response providers rallied with the California Public Utilities Commission and the state's three investor owned utilities, Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison, in anticipation of the DRP's expiration in 2007 to reshape the DRP into a true demand response program and maximize benefits from participation. As California charges through the design of its energy efficiency and demand response programs, other states can learn from its struggles and ultimately its solutions.

Background: Creation of the Demand Reserves Partnership

Following its 2001 energy crisis, the State of California took active measures to shift deregulated energy purchasing power to a non-partisan government organization in an effort to protect ratepayers and prevent further market manipulation. The State created the California Consumer Power and Conservation Financing Authority, abbreviated to California Power Authority (CPA), to secure affordable power, encourage conservation and efficiency, and increase renewable energy in the State's supply portfolio. Ultimately, the CPA aimed to prevent another energy crisis from occurring.

As part of its initiative, the CPA developed the Demand Reserves Partnership (DRP) in conjunction with the Department of Water Resources (DWR) to reserve up to 1,000 MW of clean energy. The DRP contracts businesses, governments, and water districts to curtail electricity consumption in response to economic and market conditions. This demand reduction substitutes the need for additional fossil-fuel powered electricity production. The DRP, which runs from 2002 to 2007, is unique in two ways: It is the only California-based demand response program outside utility jurisdiction—the DRP is available state-wide—and it is the only demand

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response program in California open to third-party demand response providers, also known as Aggregators.

The DRP garnered attention and gained some momentum; in 2003, DRP participants delivered 250 MW of capacity back to the grid via load curtailment, mostly through the water districts, and did so more economically than the cost of wholesale power during peak periods.[2]

DRP Program Flaws

However, after the DRP was implemented in 2002, the program did not deliver as expected. The DRP program structure had a number of problematic elements. Specifically, the $80/MWh price trigger, though reasonable in 2002 when the program started, caused near daily DRP events because of increased natural gas prices. In 2005, natural gas prices spiked from $6/mmbtu to $10/mmbtu as a result of increased oil prices in the world market and higher overall demand, and much of California's generation is fired by natural gas. Additionally, though Hurricanes Katrina and Rita had not yet hit the country, the hurricane threat to the Gulf region also caused oil and natural gas prices to soar. As a result, the electricity market reached or surpassed the $80/MWh trigger price of the DRP nearly everyday, regardless of system conditions; the DRP had essentially become a mandatory price response program.

Customers who enrolled in the program to support the grid found themselves called to service even when power grid and weather conditions did not warrant a DRP event, and the constant and seemingly unnecessary initiation of DRP events put considerable and unexpected strain on DRP participants.

The price trigger also affected the efficacy of DRP event notification. DRP event notification involved two steps: a day-ahead reservation and a day-of call for curtailment. Because of the market conditions and daily qualification of the price trigger, DRP participants received day-ahead reservations nearly everyday, nullifying the purpose of the reservations. DRP participants instead had to rely on a two-hour notification the day of the DRP event, and typically demand response participants expect higher financial incentives for day-of demand response programs.

Additionally, the baseline methodology used to calculate performance during DRP events understated the actual delivered capacity. The DRP baseline was calculated as the average of the previous ten business days less the highest and lowest reading days and DRP event days. Because of the frequency of events, baselines were subsequently determined only by low-load data points, leading to an artificially low baseline profile, understated performance results, and unrealistic program targets.

Reforming DRP: The Capacity Bidding Program

Since October 2005, EnerNOC and other demand response providers rallied with the California Public Utilities Commission (CPUC) and the State's three investor owned utilities (IOU), Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison, in anticipation of the DRP's expiration in 2007 to reshape the DRP into a more effective demand response program.

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[2] Source: California Consumer Power and Conservation Financing Authority

Demand response providers actively worked with the CPUC and IOUs to provide customer insights, improve program trigger and baseline methodologies, and lobby for higher capacity payments.

On October 19, 2006, following extensive negotiation, the CPUC approved the replacement of the DRP with the Capacity Bidding Program (CBP).[3] Improvements captured in the CBP include a completely revised event trigger, explicit distinction between day-ahead and day-of programs, a more accurate baseline calculation, and increased financial incentives for CBP participants.

New Heat Rate Trigger

Together with the IOUs, EnerNOC advocated the utilization of a heat rate trigger to replace the current price mechanism, and the CPUC approved the change in its October 19 resolution. A "heat rate" refers to a power plant's efficiency: Older plants exhibit heat rates of 10,000-15,000 btu/kWh, while newer combined-cycle gas units achieve efficiencies of 7,500 btu/kWh. Power plants are generally called in order of efficiency, from most to least efficient, and under DRP rules, CPA and DWR activated DRP events at an implied heat rate of 11,500 btu/kWh. Essentially, customers were called to provide "negawatts" to the grid as often as an aging coal power plant. The CBP incorporates a more stringent heat rate trigger of 15,000 btu/kWh so that CBP events will only occur when the day-ahead markets anticipate requiring generation from inefficient power plants with a 15,000 btu/kWh heat rate. This ensures that CBP participants will only be asked to reduce their usage during times of extreme demand when it matters the most.

Explicit Differentiation Between Day-Ahead and Day-Of Programs

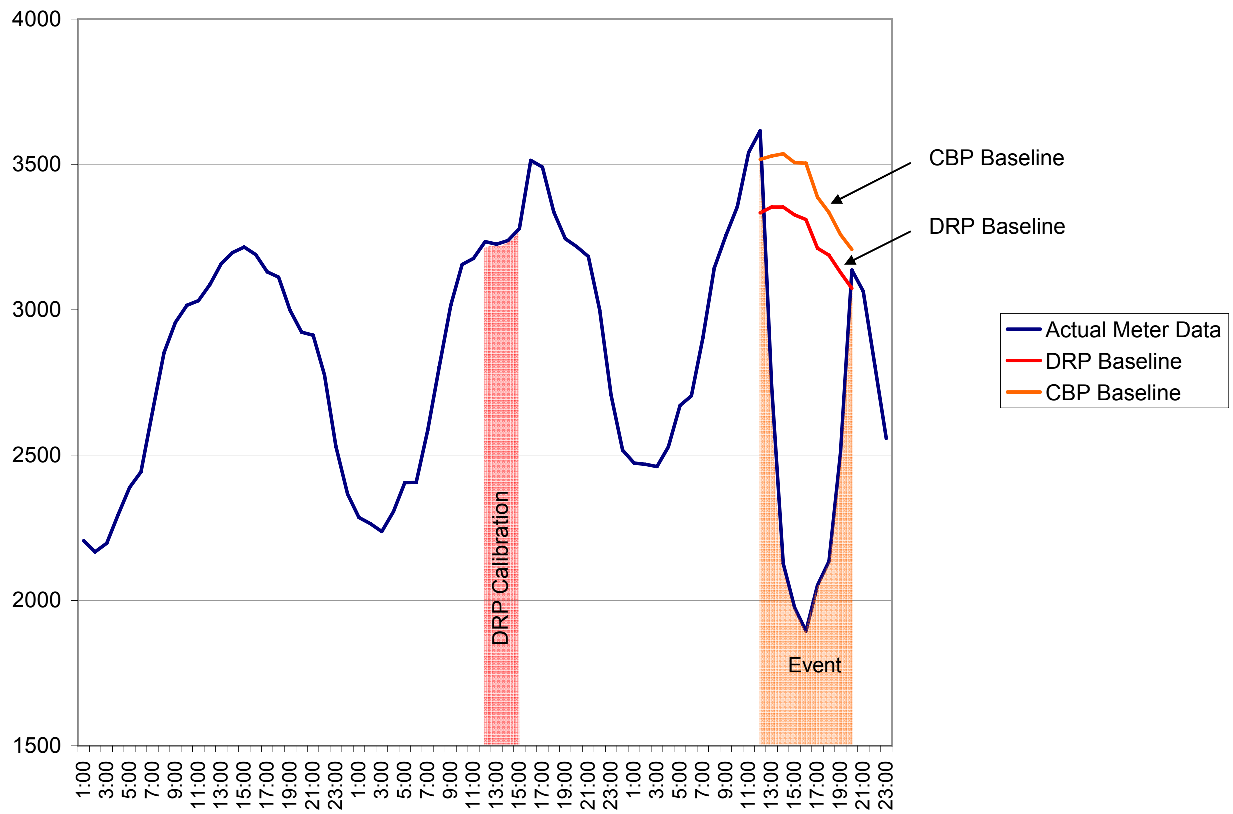
The CBP also defines guidelines to distinguish day-ahead from day-of programs. Utilities will provide day-ahead notifications by 3:00 pm and a one hour advanced notification for day-of programs. The day-of programs will offer higher capacity payments to participants based on the increased value to the system of resources capable of providing faster dispatch.

Revised Baseline Calculations

DRP event performance and payments are measured against an unsuitable baseline calculation that distorts actual customer curtailment, which is especially critical considering a ±30% variance in performance when comparing multiple baseline calculations. EnerNOC developed and heavily lobbied for a revised baseline calculation that more accurately represents delivered capacity, which the CPUC approved for the CBP. Instead of averaging low-load days to determine baselines, the CBP will consider ten eligible days (non-event business days) of the trailing 30 calendar days, and the five highest hours will determine the pre-adjusted baseline, effectively emphasizing higher-load hours. This revised baseline will better reflect CBP customer performance during events; by increasing the number of high-load days used in the baseline calculation, performance will be measured against a more appropriate and higher baseline.

[3] Source: CPUC Resolution E-4020

Figure 1. Baseline Comparison



Improved Financial Incentives

To offer as much flexibility as possible, the IOUs segmented CBP participation into three categories: 1-4 hours, 2-6 hours, and 4-8 hours. Associated capacity payments vary by utility and are fixed for two years, 2007-2008, to attract and encourage program participation and minimize customer confusion. Customers who curtail <75% of their nominated capacity forfeit their capacity revenue, and customers below 50% are subject to penalties.

Table 1. IOU Capacity Payments[4]

PG&E Capacity Price ($/kW-Month)

Product	May	June	July	August	September	October
1-4 Hour	0.00	3.71	15.60	21.57	13.30	0.00
2-6 Hour	0.00	3.71	15.60	21.57	13.30	0.00
4-8 Hour	0.00	3.71	15.60	21.57	13.30	0.00

SCE Capacity Price ($/kW-Month)

Product	May	June	July	August	September	October

[4] Source: CPUC Resolution E-4020

1-4 Hour	4.05	6.30	14.85	17.10	9.45	2.25
2-6 Hour	4.95	7.70	18.15	20.90	11.55	11.00
4-8 Hour	4.95	7.70	18.15	20.90	11.55	11.00

SDG&E Day-Ahead Capacity Price ($/kW-Month)

Product	May	June	July	August	September	October
1-4 Hour	5.37	7.35	13.54	15.11	9.77	4.71
2-6 Hour	5.51	7.54	14.07	15.63	10.06	4.81
4-8 Hour	5.65	7.76	14.71	16.23	10.49	4.94

SDG&E Day-Of Capacity Price ($/kW-Month)

Product	May	June	July	August	September	October
1-4 Hour	6.44	8.82	16.25	18.13	11.72	5.65
2-6 Hour	6.64	9.04	16.89	18.75	12.07	5.78
4-8 Hour	6.79	9.31	17.66	19.48	12.59	5.93

Customers also receive energy payments equivalent to the market value of their delivered capacity (up to 150% of nominated capacity).

What Does This Mean?

California leads the country in setting environmental and energy efficiency policies and has done the same with its lofty demand response goals. Its aim to meet 5% of its peak demand with demand response and to put demand response at the top of its loading order is a true sign of the State's commitment to this clean, dispatchable resource. However, as California charges through the design of its demand response programs, how does it influence and affect end-use customers, IOUs, and PUCs in the other 49 states?

Interestingly, California lags behind New England, New York, and PJM in the demand response arena. As California struggled through its DRP program, other regions in the country established far more stable and successful demand response programs. But is California really behind or simply struggling at the next level up?

California's DRP program, though flawed, was a bold initiative to secure up to 1,000 MW of the cleanest energy available. In addition, given California's experience with the energy crisis in 2001, the majority of commercial, industrial, and institutional organizations already attempted to optimize their energy usage, narrowing performance potential. But one can't consider the concept a step backwards in progression. As the United States advances toward cleaner energy sources, more regions will likely follow California's example.