Direct participation of electrical loads in the California independent system operator markets during the summer of 2000

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1. SYNOPSIS

Interruptible loads assisted California's electricity system operators in 2000 but could not prevent severe market problems caused by imbalance between wholesale and retail prices.

2. ABSTRACT

California's restructured electricity markets opened on 1 April 1998. The former investor owned utilities were functionally divided into generation, transmission, and distribution activities, all of their gas-fired generating capacity was divested, and the retail market was opened to competition. To ensure that small customers shared in the expected benefit of lower prices, the enabling legislation mandated a 10% rate cut for all customers, which was implemented in a simplistic way that fossilised 1996 tariff structures. Rising fuel and environmental compliance costs, together with a reduced ability to import electricity, numerous plant outages, and exercise of market power by generators drove up wholesale electricity prices steeply in 2000, while retail tariffs remained unchanged. One of the distribution/supply companies entered bankruptcy in April 2001, and another was insolvent. During this period, two sets of interruptible load programmes were in place, longstanding ones organised as special tariffs by the distribution/supply companies and hastily established ones run directly by the California Independent System Operator (CAISO). The distribution/supply company programmes were effective at reducing load during the summer of 2000, but because of the high frequency of outages required by a system on the brink of failure, customer response declined and many left the tariff. The CAISO programmes failed to attract enough participation to make a significant difference to the California supply demand imbalance. The poor performance of direct load participation in California's markets reinforces the argument for accurate pricing of electricity as a stimulus to energy efficiency investment and as a constraint on market volatility.

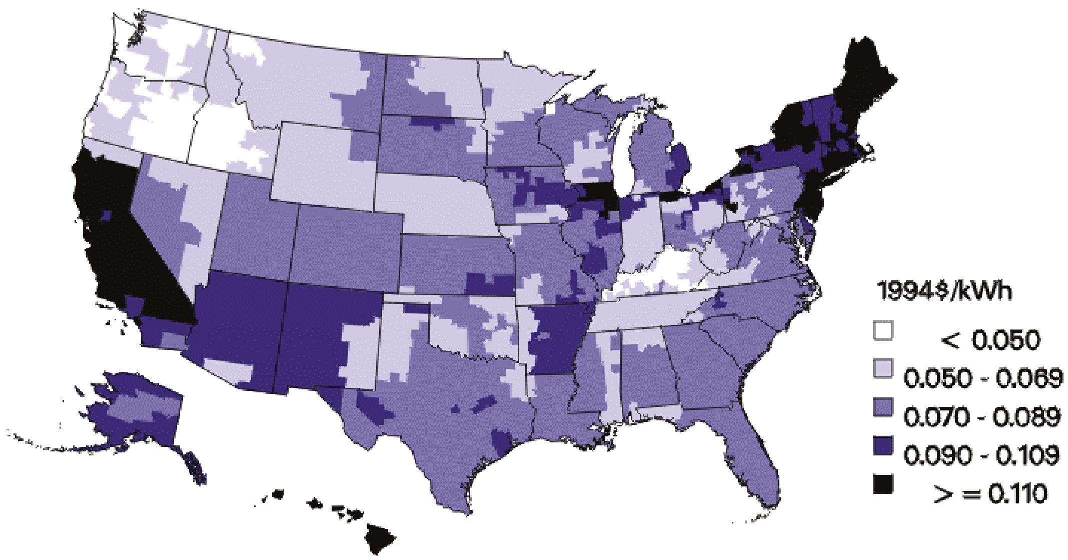
3. INTRODUCTION

California's competitive electricity markets opened on 1 April 1998 and failed at the end of 2000. This paper describes the history of this experience, explores the roots of the failed competitive experiment to be found in a legislated price freeze, and explains the role played in this drama by two groups of interruptible load programmes.

While restructuring has been initiated for various reasons in various jurisdictions, the trend towards establishing increased competitiveness in the electricity industry is a worldwide phenomenon. In the California case, the drive to lower electricity prices was the pre-eminent motivator. California's electricity industry restructuring was to move quickly towards a fully open competitive market, which the state government and regulatory agencies were convinced would lower electricity prices for Californians. Figure 1 shows that in the early 1990's California found itself as one of the U.S. regions with high electricity prices, in contrast to its neighbours. Restructuring of the state's electricity industry was intended both to stimulate generator competition, thereby lowering prices within the state, and to encourage imports from neighbouring areas into relatively high priced California. The three large existing vertically integrated investor owned utilities (IOU's) were functionally divided into generation, transmission, and distribution/supply companies, as is described in more detail below. Distribution continued to be regulated by the State, few small residential or commercial customers changed to independent suppliers, and the now distribution/supply only companies (confusingly) continued to operate under the same names as the former IOU's. Here they are simply called the *distribution/supply companies*. New institutions were established that would run electricity markets and operate the transmission systems of the three companies jointly as one control area (Grønli 1999). This competitive new structure, combined with stable natural gas prices and expanded access to imports of electricity from lower cost producers out of the state were confidently expected by all parties to the legislative consensus to result in the promised electricity price reduction.

One of the key political issues revolved around the problem of fairly dividing the cost saving bounty. Because there was a serious concern among many parties that restructuring might benefit only those large customers able to negotiate their own agreements with electricity suppliers, an across the board price freeze was imposed by the California State Legislature. The freeze promised to keep customer tariffs at 10% below their 1996 level, sadly it was ultimately implemented in a clumsy manner that kept both level and pattern of rates exactly as it was in 1996. While generators' costs fell in 1998 and 1999, they rose spectacularly and unexpectedly in 2000, imposing a heavy cash squeeze on the distribution/supply companies, and driving one of them into bankruptcy. Only when the wholesale electricity price increase came did industry executives realise they had miscalculated the dangers of the restructuring exercise undertaken, and had agreed to a plan that (in retrospect) was so risky. At the same time, regulatory response to the rapidly changing conditions during 2000 was ponderous and confused, ultimately allowing the pricing flaw to cripple California's electricity industry institutions (Stoft 2001).

Figure 1: U.S. Residential Electricity Prices in 1993



At the beginning of 2000, all three of the distribution/supply companies had interruptible tariffs that had been in place for over a decade but that had rarely been invoked. In early 2000, CAISO tried to augment the total available interruptible capacity by introducing two programmes of its own. While these provided valuable emergency capacity to the CAISO, they offered no more than temporary relief to problems that only fully price responsive demand could have addressed.

Geographical Background

California has a large land mass, 411 000 km^2 (larger than Germany but smaller than France), and the largest population of any U.S. state, 34 million, which grew over the 1990's at an average rate of 1.2%/a. Population is concentrated in two large urban areas, Los Angeles with about 16 million inhabitants, and the San Francisco area with about 7 million. If a country, California's economy, which is about the size of Canada's or Spain's, might qualify it as a G7 member. In common with the large European economies, California depends heavily on imported energy.

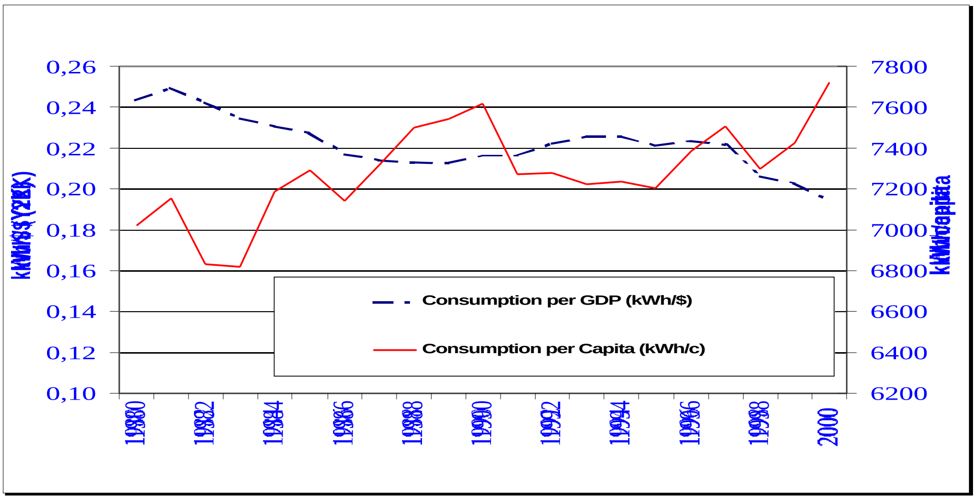
Electricity Use

In 2000, total electricity consumption was approximately 260 TWh and total capacity of the State's power system was about 50 GW. The equitable Mediterranean style climate and widespread access to natural gas for space heating limits annual electricity demand to around 7700 kW_h/capita, which is far below the U.S. national average of around 12 000, but is still large compared to southern Europe, whose climate is similar to coastal California. Spain, for example averages about 4 500 kW_h/capita. Some interior areas of California have quite harsh climates, and the trend is for population movement towards these more hostile regions, with significant electricity use consequences.

It has been an often repeated myth that California's problems have been brought about by the rapid growth of its high tech sector combined with the state's strict environmental restrictions. It is certainly true that California's economy has boomed in the last five years, leading to significant demand growth (about 2.5%/a over the last 5 years). However, the recent rate of growth has not been exceptional by historic standards, nor is there any evidence that the structural changes taking place as the information age arrives are having a significant effect on patterns of electricity use, which are still driven, for the most part, by climate. During 1991-2000, California's electricity demand grew at an overall rate of 1.83%/a, although the pace accelerated considerably over the last 5 years of the 1990's to 2.52%/a. The rate of growth was actually higher, 3.07%/a, in the 1980's, and historically, much faster rates than this have been common.

Figure 2 shows two indicators of the overall trend in the pattern of demand. The solid line (right hand scale) shows per capita usage, which has indeed increased over the two decades presented. While this increase is cause for some worry, the overall rate of change is not dramatic, at about 0.4%/a.

Figure 2: California Electricity Consumption Per Capita and Per Dollar of GDP



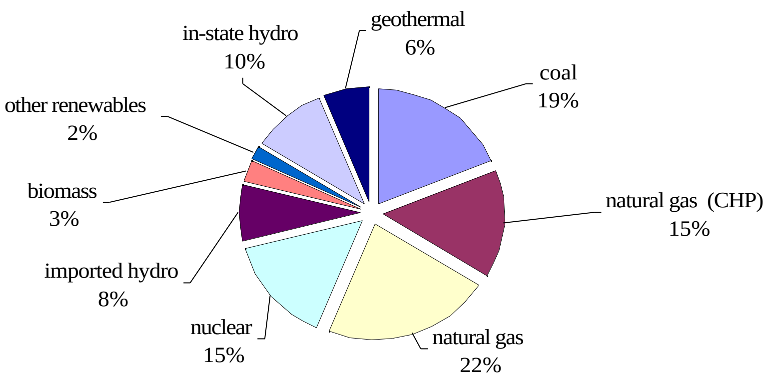
The dashed series (left hand scale) shows the electricity usage efficiency of the California economy in the form of electricity use per dollar of real GDP. A barely discernible pattern emerges in which the electricity efficiency of the economy improves in expansionary times and stabilises or deteriorates in times of stagnating economic activity. This pattern is in strong evidence over the latter half of the 1990's, when a rapid economic expansion occurred together with a fall in the electricity intensity of the economy. If California were experiencing a structural change, implying that the internet economy needs to be more electricity intensive, this curve should be turning up, and not down. In any case, all office, telecom, and networking equipment combined accounts for only about 3% of electricity consumption. A dramatic change in usage in this small segment of electricity demand would be needed before a significant change in aggregate electricity use patterns would be noticed.

Electricity Generation

California has long enjoyed a diverse fuel mix. Figure 3 shows the shares of each generating fuel. Since the state is a large importer, typically accepting 25-30% of all its electricity from neighbouring states and Canada, the likely composition of the imported electricity is also included. By far the dominant fuel within the state is natural gas, although most of the gas fuel is itself imported. About 5 GW of the natural gas capacity is in the form of combined heat and power (CHP), not under the control of the major utilities, but whose power they were historically required to buy. Nuclear is also an important contributor. There are two large nuclear stations within the state, Diablo Canyon and San Onofre, and a large Arizona nuclear station, Palo Verde, primarily supplies California. While a significant share of California's electricity supply is from coal, all of this power is generated outside the state.

Hydro is still a significant source of both in-state and imported power. This dependence on hydro forms an important feature of the supply picture because the variability of the hydro resource was a major potential source of instability in electricity markets. The current dry hydro conditions in the Pacific Northwest with the resulting fall in California's ability to import has been perhaps the most significant single cause of the ultimate demise of the restructured market. Finally, as a result of an active policy to ensure a diverse energy supply, California has achieved a high share of generation from so-called *eligible renewables*, which are ones able to receive state subsidies. Overall, these represent about 11% of the fuel mix, with geothermal providing more than half of this total.

Figure 3: Approximate California Power Generation Fuel Mix (Including Imports)



Historical Background

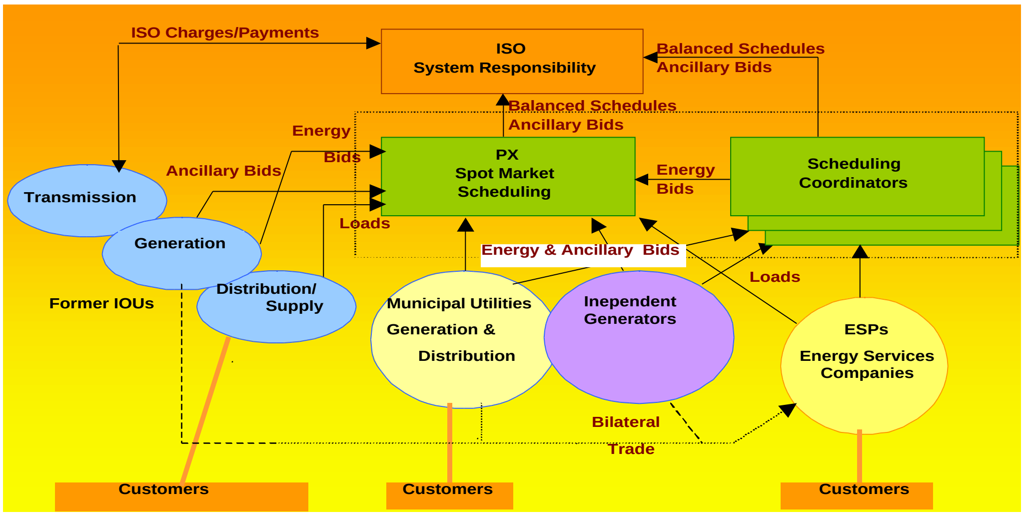
At the time of restructuring, the state had three major investor owned vertically integrated electricity companies, Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). Together these three major companies supplied about 75-80% of all the electricity delivered to California customers at the time of restructuring. The whole exercise has been focused on these three companies, and they are often together thought of as synonymous with California, but the true picture was much more complex. PG&E and SCE are large companies, each with over 4 million customers and vast service territories. SDG&E is much smaller, just serving the area around San Diego County. All three were fully vertically integrated companies that controlled generation, transmission and distribution, and PG&E and SDG&E are also gas distribution companies. There are two large municipal utilities. Los Angeles is served by the Los Angeles Department of Water and Power (LADWP), and the Sacramento Municipal Utility District (SMUD) serves the state's capital city. These municipal companies, and about 40 other smaller ones, together with other agencies that provide electricity, are not subject to the same regulatory oversight of tariffs as IOU's, whose rates are set by the California Public Utilities Commission (CPUC). This complex starting point for restructuring is an unfamiliar one for many analysts accustomed to thinking of the restructuring process as beginning from a much more centralised system. Even within the U.S., the other major restructurings to date have been based on pre-existing tightly organised pools. The challenges of moving towards an abstract design for an ideal market are more challenging in many ways because of the diversity of the institutions involved, their complex cultures, histories, and regulatory structures, and the lack of technical experience with co-ordinated operation.

Market Structure

In September 1996, then California Governor Pete Wilson signed the California electricity industry restructuring legislation, AB-1890, which implemented complex recommendations that had been developed over some time by the CPUC and released less than a year earlier. The prior IOU's were functionally divided into their generation, transmission, and distribution activities. Generation would become a competitive activity, with the utilities required to sell much of their generating assets to new entrant companies and, as explained below, encouraged to sell more. Transmission would be a regulated service, which because of the nature of divided authority between levels of U.S. government, would fall directly under federal regulatory oversight by the Federal Energy Regulatory Commission (FERC). The distribution network business would remain as a traditional regulated utility under CPUC jurisdiction, and hence the three prior companies became known in California regulatory jargon as utility distribution companies (UDC's); however, given the failure of true retail competition to flourish, here they are being called distribution/supply companies. In fact, strict division of the

IOU's was never really enforced by the CPUC and pre-existing generation, transmission, and distribution/supply assets were all operated from the same buildings with much the same staffs. Consequently, as the market unraveled in late 2000, the state was able to quickly partially reverse the process, for example, requiring the distribution/supply companies to supply only themselves with power from the hydro, nuclear, and coal stations that they still owned.

Figure 4: Market Structure Established by AB-1890



Moving anticlockwise through figure 4, the municipal utilities remained largely unchanged. Entry by independent generators through the acquisition of divested utility assets as well as new construction was encouraged, and an active competitive retail supply market involving new independent electricity suppliers, called energy service providers (ESP's) in California regulatory jargon, was envisaged. One of the most controversial features of the California structure was the attempted cleavage between financial and physical operations of the power system. In figure 4, this division is represented by the *PX* and *Scheduling Coordinators (SC's)* boxes versus the *ISO System Responsibility* box, this later function being in the hands of the California Independent System Operator (CAISO). Most restructuring efforts are built around the notion that a central system operator must both operate the power system and run a centralised market of some kind. In the California case, there was a semi-official market, the California Power Exchange (CalPX), but, in principle, it was only one of potentially numerous SC's able to match buyers and sellers of electricity and execute trades between them. The SC's were expected to submit balanced schedules to the CAISO, whose job was merely to execute them in real-time and cope with any supposedly small imbalances that emerged as a result of unexpected deviations from planned schedules. A key difference between the CalPX and other SC's was that the distribution/supply companies were required to purchase their power in the CalPX, and to schedule all generation they controlled, both their own and that under contract, through the CalPX. The CPUC has continued in its role as regulator of the three distribution/supply companies and the retailing aspect of the industry. It also oversees operation of the generating assets still in distribution/supply company control, as well as its contracts still in place. Although there is virtually no federal legislation in place regarding restructuring, regulation of the CalPX and CAISO moved to the federal level in the form of FERC.

Divestiture and Stranded Assets

A key feature of AB-1890 was that the investor owned utilities were authorised to fully recover their stranded assets over a four-year transitional period, or faster, if possible. This collection would take place by means of a *Competitive Transitional Charge* (CTC) to be added to customer bills. The fateful aspect of this arrangement was that customer rates were frozen until the time of full recovery of stranded assets, with accumulated CTC collections rising or falling to counter any fluctuations in wholesale electricity procurement costs to the distribution/supply companies. *Stranded assets* are an accounting construct that consists partially of the difference between the book and market values of physical assets, primarily generating stations, and partially of the cost of historic financial commitments that may not be economic under post restructuring conditions, such as contractual obligations to buy power at above market prices. In essence, the authority to fully recover stranded assets meant that the Legislature (on behalf of the ratepayers) accepted that the accumulated debt for bad past investments made by regulated entities would be recovered in customer tariffs. Note that these costs are the consequence of IOU decisions originally approved by the CPUC as prudent investments and made under the expectation that costs would be recovered. Initial estimates of total stranded assets approached 30 G$,[1] which coincidentally is not much more than the annual total of all electricity bills of all the state's customers.

Only after the stranded assets had been recovered, the distribution/supply companies could file applications with the CPUC to move beyond the transition, at which time the full collection of wholesale electricity costs in rates would be authorised. Until mid 2000, recovery of stranded assets was faster than generally anticipated, primarily because generators recognised the value of the generating stations offered for sale by the IOU's, and paid higher prices for them than expected. AB-1890 actually required PG&E and SCE to sell only 50% of their thermal generating capacity, while there was no such obligation on SDG&E. In fact, the IOU's met and surpassed this requirement because they wanted to move beyond the transitional period, and escape from the rate freeze. All gas fired generation of all three companies was quickly sold. Of the big buyers, Duke, Mirant, and Reliant are unregulated subsidiaries of utilities from other parts of the U.S., while AES, Calpine, and Dynegy are independent power generation developers.

PG&E retains only its considerable (≈ 4.1 GW) hydro and (≈ 2.2 GW) nuclear generation, and attempted to develop a plan acceptable to the CPUC for selling the hydro. SCE's hydro capacity is quite small but owns considerable (≈ 3.5 GW) nuclear and (≈ 2.0 GW) of out-of-state coal. SCE also has partial interest in three coal stations, Mohave, Intermountain, and Four Corners, which it had planned to sell to AES; however, this sale was blocked by the CPUC in late 2000 because of the looming crisis. Only SDG&E met the goal of recovering stranded assets before the crisis, and its large-customer rates rose to competitive levels as a result (Bushnell 2001). Although SCE claimed to have recovered its stranded assets, the CPUC disagreed and denied its request to move to the post-transitional phase. PG&E was also within sight of recovery and the sale of its hydro assets would have put it over the top.

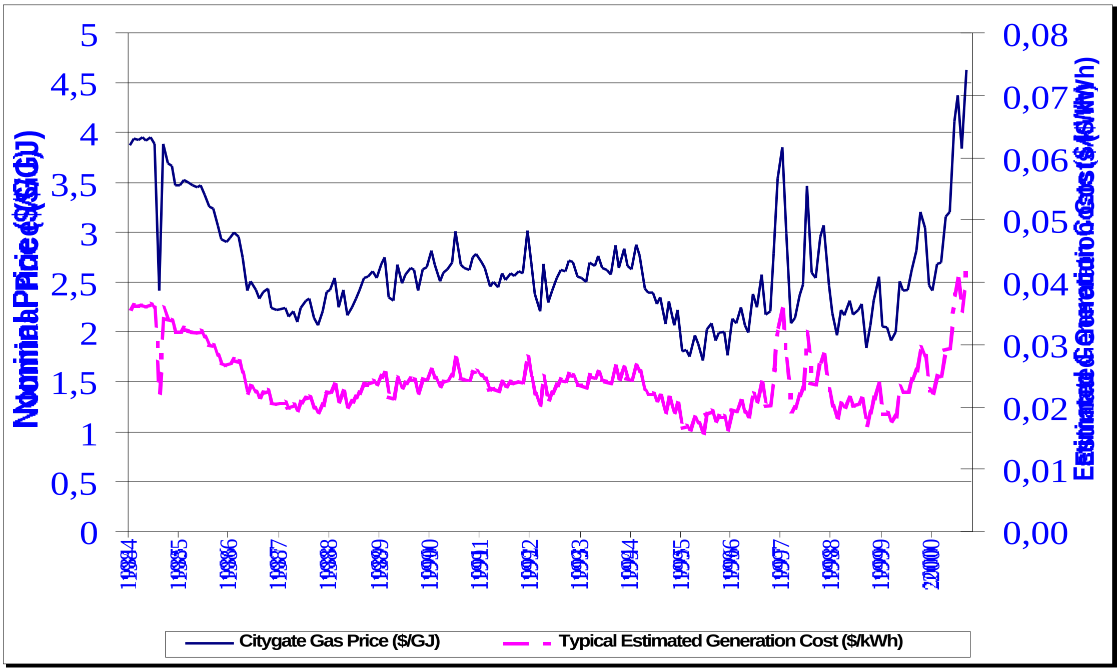
The restructuring stimulated a significant number (about 30) new project proposals, totalling in the order of 15 GW. About 2.5 GW of this capacity has obtained licensing from the CEC and was moving into construction by the beginning of 2001. The first of these new stations, Sutter, is scheduled to be on line in the summer of 2001. This station together with a second being built by the same independent company, Calpine, will make it the state's biggest generator.

Rate Freeze

The root cause of the collapse of California's restructured electricity market was the imposition by AB-1890 of a rate freeze. The law granted a 10% across the board rate reduction to all customers covered by the restructuring, i.e. the customers of the three former IOU's. Customer bills show the basic components of costs, generation, transmission, and distribution/supply. These are the true costs experienced over the month for which the billing takes place. Until closure of the CalPX, the generation cost was an estimate of the cost of purchasing a typical customer class load shape. Additionally, the bill showed two financial components, the CTC collection and a Trust Transfer Account (TTA). The TTA was a repayment of a state bond issue floated in 1996 to partially fund the rate reduction. The strange aspect of the bill was that, despite its appearance, these are not components of the actual total due. Rather the bill total is predetermined by calculating the equivalent bill total for the same level of usage at 1996 tariffs. This 1996 total minus the legislated 10% discount is the actual amount charged to the customer. The CTC collection is added to a balancing account maintained to repay the company its stranded assets. When the fixed 1996 bill total minus 10% began failing to cover rapidly escalating costs of electricity procurement, the CTC went negative, and stranded asset recovery went into reverse. By April 2001, the losses accumulated by the distribution/supply companies had reached about 18 G$.

Everything unravelled with surprising speed in the summer and fall of 2000. U.S. natural gas prices were deregulated in the 1980's and prices fell. Figure 5 shows that between 1985 and mid 2000, natural gas prices were surprisingly stable in nominal dollars. During the first two years of restructuring, it did not seem that this pattern would be broken. The lower series and right side axis show the approximate generation cost that these prices represent. Naturally, these too were quite stable over the period, typically in the 2-3 ¢/kW_h range. These gas prices are a reasonable guide to actual generator fuel costs over the long run, but the spot price is a better guide to the likely electricity price because the marginal generator is likely to be one buying natural gas on the spot market and selling gas is its opportunity cost of generating. The spot price crept up and up during 2000, and generation costs rose accordingly. Then in mid November prices rose to an even higher plateau that kept prices around 10 $/GJ, where they remained until March 2001. Further, during early December, a remarkable price spike occurred, with prices nearing 50 $/GJ at one point.

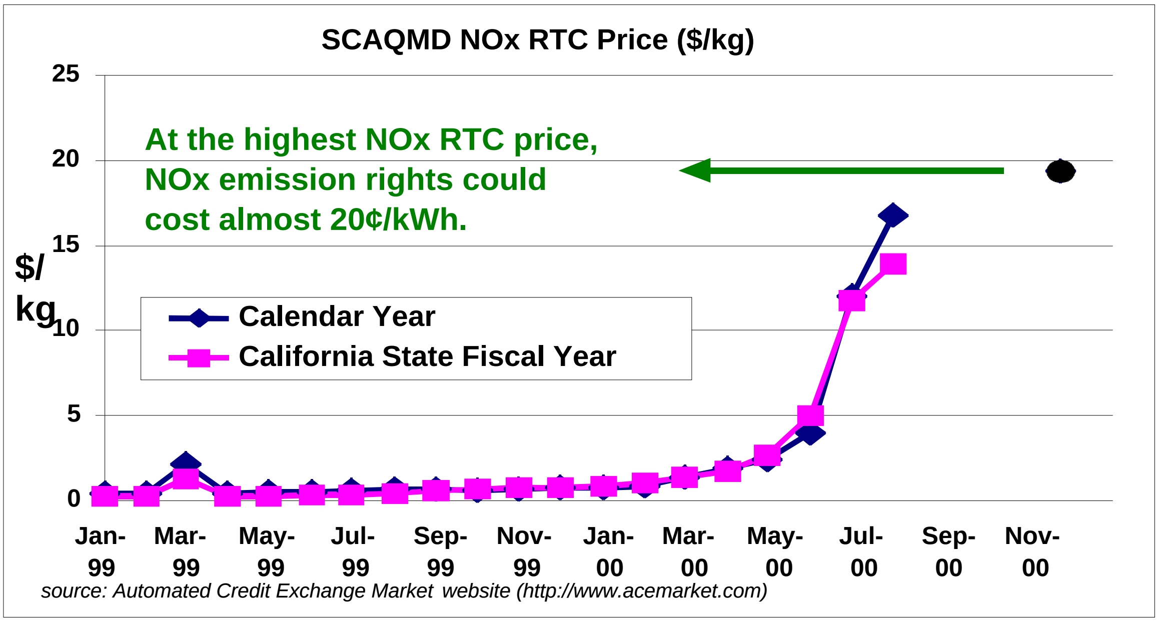
Figure 5: PG&E Citygate Natural Gas Price and Estimated Generation Cost



Summer 2000

Another generator cost that escalated dramatically in 2000 was the price of NOx emission credits, as shown in figure 6. These credits are know as RECLAIM Trading Credits (RTC's), RECLAIM being the name of the programme under which they were developed. The South Coast Air Quality Management District (SCAQMD) regulates air quality in the Los Angeles basin. SCAQMD began a system of tradable emissions permits in 1995. Over the first few years, the price of these credits was low and stable. The ownership of credit entitles the owner to emit a kg of NOx into the SCAQMD air over one of the time periods shown. Figure 6 shows the prices paid at various auctions during 1999 and 2000 for these tradable credits. The pattern is self-evident, prices have reached unprecedented levels. The last point, in black, had a different marker because the permits traded were of a different type. This auction in December 2000 generated the highest prices ever. As a rough guide to the possible effect of these emissions trading prices on electricity prices, this highest ever price has been converted at the emission rate of the dirtiest generator in Los Angeles for which data is available. The result of this calculation is that the cost of the NOx emissions rights to an extremely dirty generator could reach 20 ¢/kW_h. The worst case is only interesting here because if this generator sets the market price, all others would have received it.

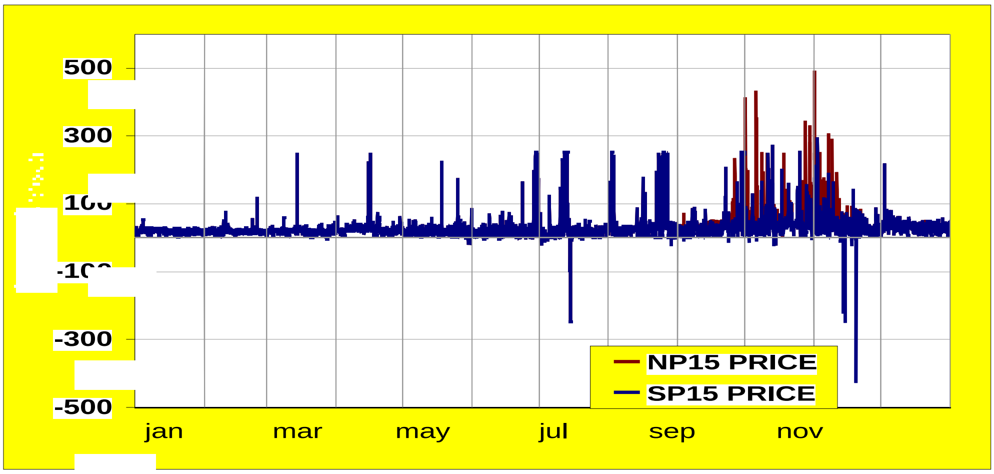
Figure 6: Auction Prices of RECLAIM Trading Credits for NOx



Collapse of the markets

Figure 7 shows the record of the CAISO's Imbalance Energy Market (IEM) during 1999. The IEM is a market organised by the CAISO and originally intended to trade only a small share of total energy, basically whatever was needed to true up any imbalances in schedules submitted to the CAISO. In reality, schedules had significant imbalances since the opening of the market and the size of the imbalance steadily grew. At times, 30% of energy has been acquired by the CAISO from the IEM. Offers to the IEM are in the form of incremental and decremental offers to the schedules submitted by SC's. During 1999, the IEM worked well. There were price spikes that are typical of electricity markets, but overall prices were not significantly higher than CalPX prices, despite the high volumes traded.

Figure 7: Prices for Imbalance Energy in Northern and Southern California in 1999

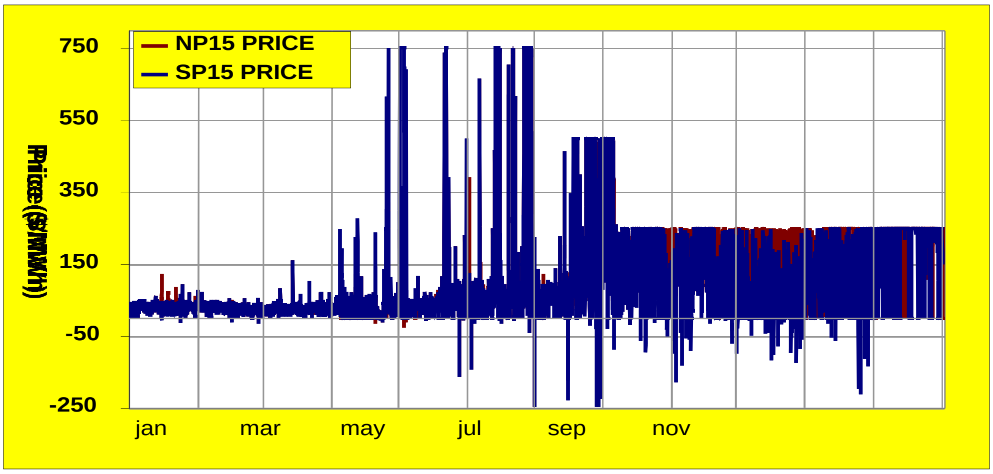


Remember that the distribution/supply companies were required to buy from the CalPX. Additionally, they had only limited authority from the CPUC to contract, buy forward, or otherwise hedge their purchases. In other words, their primary alternative to the CalPX day and hour ahead markets was the CAISO IEM. Further, since the IEM was capped, there was a strong reason to never pay above this cap for energy in the CalPX markets. The reasons for the high volumes of sales in the IEM are not entirely clear, but certainly one appears to be that the generators prefered to offer themselves in the IEM, rather than in the CalPX. This was in part because of the system of competitive procurement of ancillary services (AS) that California has. The CAISO runs five AS markets in addition to the IEM. These are markets for 5 different classes of backup capacity. When the generator offers itself into these markets, however, it must also post a price for any energy it produces. In times of tight supply, therefore, the generator has a chance to be accepted as an AS and asked to generate to provide the much needed energy. This results in a total payment above the maximum possible revenue from the CalPX because no buyer there would pay more than the capped IEM price alone, knowing the CAISO must provide this power at the cap.

Trouble began in the California markets in May 2000. An unseasonable early heat wave at a time of the year when many plants are out for scheduled maintenance resulted in a significant price spike. This was followed by a series of spikes in June, most notably on June 14 which was an exceptionally hot day in northern California, with the temperature reaching a record 40ºC in San Francisco. This was the first day that involuntary outages were ordered by the CAISO, although it was actually not a Stage 3 emergency, the level at which customer outages are usually initiated. In other words, these outages were not the result of a true adequacy shortage because the heat wave was localised.

The high cost of IEM procurement led the CAISO to lower the price cap from the existing 750 $/MWh to 500, which did not stop the high prices. Subsequently, the price was again lowered to 250 $/MWh. These price reductions seemed to have the effect of lowering peak prices but raising average prices, as may just be discernible in the graphic.

Figure 8: Prices for Imbalance Energy in Northern and Southern California in 2000



Ultimately, in December, when natural gas prices hit their all time high, capacity offered into the markets appeared to lower, resulting in the calling of several emergencies in the early part of that month. This culminated in the first ever call of a Stage 3 emergency on 7 December 2000, meaning that reserves available to the CAISO had fallen below the critical 1.5% level.

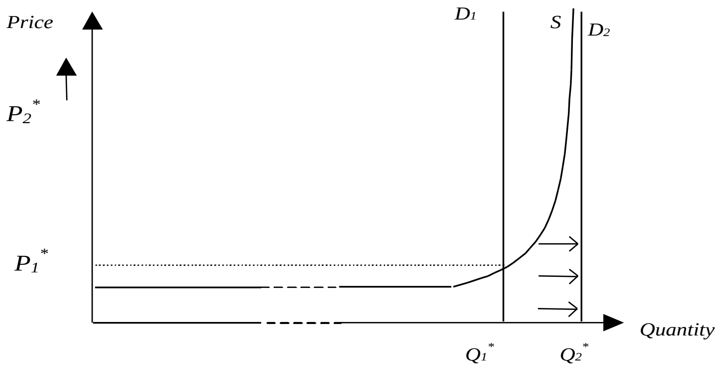
From this point on the ultimate collapse of the market was probably inevitable. A political firestorm began because PG&E and SCE were running out of cash and nearing bankruptcy. To recover the CTC, they required prices to be lower than around 6 ¢/kW_h, on average, while the equivalent price for December reached 33 ¢/kW_h. In other words, PG&E lost about 27 ¢ on every kW_h delivered in that month. The total debt accumulated by PG&E and SCE by April 2001 was approximately 18 G$, or about $450 for every resident of the state, and the bill is still rising.

Demand Response

This fiasco could most likely have been avoided if the markets had been given a chance to work. The imposition of the price freeze ensured that no customers actually saw the information embodied in the wholesale market prices. As a consequence, demand was almost totally inelastic in any time period, implying that prices can go through the roof. Figure 9 shows a simple supply-demand diagram that illustrates this (Mount 2000 and Borenstein 2001a). The supply curve is a long flat one, upturned steeply at the end in the shape of a hockey stick lying on its handle. In the long range to the left, an intersection with the demand curve results in a rational price at close to marginal cost. However, near to capacity the upturned supply curve can cause prices to be highly sensitive to the location of the demand curve. The best way to tame a market operating in the dangerous range close to capacity is to enhance price elasticity, whereas in the California case, AB-1890 ensured the precise opposite. The best approach would be a real-time pricing scheme so that the demand curve could have some downward slope (Borenstein 2001b). It is clear from figure 9 that even a modest slope in the demand curve could significantly lower prices. Even if demand is not elastic over short time scales, i.e. the hourly demand curve is still vertical, ensuring that customers see prices and can respond at least monthly or seasonally would nonetheless have allowed the market to potentially function. The California price freeze fatally inhibited the market by eliminating any chance of any price response whatsoever.

Absent any price signal reaching loads through retail rates, the only slender hope for a proxy demand response comes in the form of direct participation by loads in markets. A common manner in which this can occur is through interruptible load programmes. Utilities offer reduced rate tariffs to certain customers who agree to lower demand, when ordered to do so. Given the disastrous pricing policy enforced in California, it is of particular interest, therefore, to examine the role of its interruptible load programmes.

Figure 9: Consequence of Hockey Stick Supply Curves for Electricity Markets



CPUC Interruptible Load Programmes

California has had an active interruptible load programme operated by the distribution/supply companies, under the regulation of the CPUC, in place for over a decade. These programmes have continued through the restructuring process. All three of the major IOU's had programmes in place, but SCE's was by far the largest, with about 1800 MW (about X% of its peak load in 2000), while the similar sized PG&E had only 500 MW, and SDG&E's programme was small. Both SCE and PG&E had peak demands close to 20 GW in 2000 (Goeke 1999). Customers on these special tariffs received an approximate 15% discount on their electricity bills by volunteering to be curtailed in the event of a system emergency. There are limits on the hours of interruption; 25 events of no more than 6 h per year were allowed in the case of SCE. The bill reduction that customers on these programmes received was substantial, an average of about 60-80 k$/MW_a for curtailable load, making the cost of these programmes around 220 M$/a in the late 1990's, and a total of about 2 G$ has been spent over the life of these programmes. Furthermore, because California had a quite comfortable capacity reserve until recent years, actual customer interruptions were rare or non-existent. In fact, SCE did not invoke a single interruption over the 14 year period ending in June 2000, and PG&E called only seven. In other words, California's interruptible load programmes, like many such policies, operated more as an economic development discount to large customers than as a load management programme. The only significant change that restructuring initially brought to the design of these programmes is that after CAISO took control of the grid, the initial decision to trigger interrupts came from the CAISO control room in Folsom, CA, and the distribution/supply utilities' control rooms only passed along messages.

In the case of the SCE programme, all participants must have a dedicated phone line and an attached device that delivers the interrupt notification, after which the customer has 30 min to respond by reducing load below an agreed level. The mechanics of PG&E's system are lower tech, but the principles are the same (Eto and Goldman 2001). These are involuntary interruptions and severe penalties are imposed for non-compliance with the customer's agreement, for example, SCE's penalty is 700 $/MWh.

In the summer of 2000, the situation changed dramatically for these customers because interruptions became common. The CAISO will usually issue interrupt orders when it reaches a Stage 2 emergency. A Stage 1 emergency is called when reserves fall below 7% of expected load, and this triggers calls for only voluntary load reduction. Reaching a 5% margin results in the Stage 2 call, and at 1.5%, a Stage 3 is declared. While interruptible load curtailments are usually called at Stage 2, the CAISO has considerable discretion in how it responds to declared emergencies. This is especially true in Stage 3, when general customer outages can be initiated. Deliberate involuntary customer curtailments are usually called *rolling blackouts* in California because neighbourhoods are cut off for up to 90 min, one neighbourhood at a time, according to a predetermined schedule. The first ever CAISO Stage 3 was called on 7 December 2000, but from that date until the third anniversary of the CAISO's founding, 1 April 2001, there were 36 further Stage 3 emergencies, 18 in January alone. Records of individual curtailments of customers on interruptible tariffs is considered confidential customer information and cannot be known with certainty. However, there were 36 Stage 2 emergencies in 2000, and a further 51 had occurred by 1 April 2001, so the conditions under which interruptions might have been called have existed far more times than the maximum interruption limit would allow, and, it is believed, the ceiling was reached for many customers in 2000. Because of the extremely high number of emergencies in January 2001, many customers have already reached their annual limit on numbers of incidents, especially in the PG&E service territory.

Despite these penalties, when interruptions became frequent, many customers chose to ignore their instructions and suffer the penalty. Also, the high frequency of interruptions became a serious concern in some instances. For example, the jet fuel pipeline serving San Francisco airport was operated under an interruptible PG&E rate, and fuel supplies began to fall uncomfortably low, resulting in the airport forcing its supplier to pump fuel and incur the penalties. These problems, together with the exhaustion of interrupts rendered the programme ineffectual. In early 2000, the CPUC reversed its earlier position and now allows customers to exit the interruptible tariffs.

CAISO Interruptible Load Programmes

Realising that the supply situation was serious for the summer of 2000, the CAISO attempted to instigate some last minute interruptible load programmes of its own, to supplement those of the CPUC (Miller 2000 and Doudna 2001). CAISO hurriedly designed two programmes during the spring of 2000, a Demand Relief Program (DRP) and a Participating Load Program (PLP). Both the DRP and PLP were organised as open bidding processes and were unveiled at a CAISO meeting on 22 February 2000. Loads accepted into either programme would be dispatched just like generators, but would not be allowed to set the market clearing price. To participate loads had to offer at least 1 MW of curtailment, but this could be an aggregation of customers.

The DRP had lower technical requirements than the PLP, and was intended to act like a traditional interruptible load tariff. Participants were required to have an *interval meter* installed; that is, a meter that records usage for each hourly period (or more frequently) of the month. These meters are installed at the premises of most large (> 500 kW peak demand) customers, but at very few small or medium sized ones. Distribution/supply utilities are required to install them upon customer request, but the installation charge is usually about $1500, reading them requires provision of a permanent dedicated phone line at customer expense, and the process of requesting and achieving installation was highly bureaucratic. Customers already enrolled in the CPUC interruptible load programmes were not eligible to additionally participate in this one, for fear of double payment. The offer to the CAISO was in the form of a fixed level of demand reduction below an ten-day rolling average hourly load for the customer. The customer had to demonstrate performance by recording a power reduction during each hour of the prescribed level below the average load recorded in the same hour of the day over the prior ten days. Winning offers were paid a capacity payment irrespective of whether an interruption was actually triggered and additionally received the IE price for the foregone energy. The total outage duration ceiling was 30 h/month, curtailments could only be called on work days, and each event was limited to 8 h duration. The customer response would have to be observed within 30 min of the request being issued by CAISO. All of the participants in the DRP were aggregated loads of relatively small dispersed customers and there was no fixed communication equipment requirement. CAISO used alphanumeric pagers to broadcast curtailment notices to aggregators, who, in turn, were responsible for relaying signals to their contracted loads.

The initial target was for 1000 MW of load to be signed up under the DRP. Actually, a total of 269 MW of load was offered under 67 original offers, but prices were high, causing the CAISO to only accept 180 MW.[2] The average capacity payment was (for the time) a high 36 k$/MW/month; that is, a customer signing up for the full 4 months of the programme, 15 June through 15 October of 2000, could have received fully 144 k$/MW, or about double the annual implicit payment under the CPUC interruptible programmes. Additionally, the DRP carried no punitive penalties for non-compliance, in contrast to the CPUC programmes. If a DRP participant failed to fully perform on an average level over any month, it risked only forfeiture of a share of the contracted capacity payment, as shown in table 1; any energy payments earned were still paid. If delivered load shedding was not greater than 25% of committed capacity, all the capacity payment was foregone. In order to receive the full capacity payment, the average performance in the month had to exceed 90% of the contracted level, and between 25 and 90%, partial payments were made.

Table 1: Non-performance Partial Payments for the CAISO DRP

percentage performance	percentage payment
≤ 25	0
25 - ≤ 50	25
50 - ≤ 75	50
75 - ≤ 90	75
> 90	100

As table 2 shows, the DRP was used extensively during the summer and fall of 2000, although it reached the ceiling only in June and August, which were also the months with the most interruptions called.

Table 2: Ceiling Hours, Hours Used, and Numbers of Events by Month for the CAISO DRP

month	ceiling hours	hours used	number of events
June	15	15	3
July	30	16	4
August	30	30	8
September	30	24.5	5
October	15	0	0

Table 3 shows the participant response rate for each month. Response was fair overall, but some participants performed exceptionally well. The extremely good performance of some participants was surprising, given the lack of strong incentives to perform. Since the average performance was in the range 44-66%, about a half of the contracted load reduction was not delivered, implying that about a half of the customers involved sacrificed some capacity payments, even at the high contracted prices.

Table 3: Average and Best Compliance Rates by Month for the CAISO DRP

compliance rate	June	July	August	September
average	44.3	66.0	66.4	55.4
best participant	99.7	100.0	100.0	99.5

The PLP was intended to allow loads to participate in the AS and IE markets operated by CAISO (Marnay 2000). Loads would be scheduled through scheduling co-ordinators into two AS markets, non-spinning reserves and replacement reserves. These markets require that AS respond within 10 min. These two AS are the two lowest qualities of back-up service. Loads would also be able to offer energy directly into the IEM. The bids would be considered just as generator bids are, except there was a somewhat looser imposition of some non-performance penalties that generators face, which are generally called *no-pay* provisions. A capacity payment would be given when a bid was accepted, and the IE price paid for any energy provided in real-time. Customers were required to have a 5 min interval meter installed to record the load reduction, and must meet communications requirements similar to those required of generators, although less stringent and costly.

The initial target for the programme was to sign contracts for 400 MW of non-spinning AS, 400 MW of replacement, and 1000 MW of IE. When offers for the PLP were accepted, only 5 offers were made, with proposal totals shown in table 4.

Table 4: Offered MW of Interruption into the CAISO PLP

service	low	high
non-spinning reserve	118	152
replacement reserve	289	468
imbalance energy	289	468

So few of these initial offers were followed up that only 230 MW of load actually firmed up their offer with more detail, and ultimately no load was ever interrupted under this programme.

4. CONCLUSION

The summer of 2000 was a traumatic one for California's electricity sector, and despite the fact that subsequent events have been even more disturbing, hopefully some lessons can be drawn from the summer 2000 experience. The root cause of problems in California's electricity markets was (and remains) the absence of any price responsive demand. This causes extreme price spikes in times of scarcity, and enables exercise of market power by generators. Absent any price responsive load, direct participation of loads in markets can serve as proxy and help tame volatile markets, so analysing the role played by interruptible loads in the California market nightmare is enlightening.

From an operational perspective, the existence of interruptible loads in the form of two distinct sets of programmes was a boon to the CAISO as it wrestled with the supply shortfalls that emerged during summer 2000 and recurred with a vengeance in the winter of 2000-2001. The CPUC programmes, which were the most important shedable load available to CAISO, provided great benefits in 2000, and will be sorely missed in the coming summer. The number of interruptions that occurred in 2000 far exceeded the historic pattern and response rates decayed. In many cases, customers decided that the cost of suffering repeated outages exceeded the cost of non-compliance penalties. After steadfastly refusing to do so for some time because the accrued benefits to customers on these tariffs was huge, the CPUC allowed customers to exit interruptible tariffs in early 2001. When interruptions became commonplace, customers began to re-evaluate the benefits of being on the interruptible tariffs distribution/supply companies have offered for many years, and most have decided that the benefits do not outweigh the costs. The key lesson appears to be that interruptible loads attracted by low tariffs, or indeed low tariffs masquerading as interruptible programs, will not provide reliable load reduction for a sustained period, especially if the outage rate far exceeds expectations. In other words, these loads can provide valuable emergency relief, but they cannot substantially compensate for capacity shortfalls over a sustained period. In other words, interruption weariness quickly sets in.

Neither of the two CAISO programmes could be considered a notable success, but the PLP was clearly the larger disappointment. There are some obvious reasons for this. The technical requirements made of participants were a major obstacle, and, indeed, few customers even have the basic understanding of AS and IE markets necessary to participate in them. Facing the challenges of understanding the opportunity and meeting the technical standards required to capture it over a short period, and with little promise of a sustained return on investments made the PLP was not attractive to many participants. There are some examples of successful load participation in AS markets, but they are few, for example, customer interruptions serve as a fast response underfrequency AS in New Zealand (Marnay 2001).

The DRP, on the other hand, achieved some modest success. It was able to deliver a small but valuable amount of shedable load to the CAISO, albeit at a high price. If developed over time so that some consistency and experience could be achieved, the DRP could potentially provide a useful tool to CAISO, but as of writing, the potential seems small relative to size of demand response needed to tame California’s markets.

California’s restructuring experiment reached a dramatic point at the time of writing, April 2001. PG&E declared bankruptcy and the State bought the transmission system of SCE, thereby postponing its financial demise. The State in the form of CDWR has stepped in to buy power under long term contracts, as well as open markets. It delivers this power to the insolvent distribution/supply companies for partial or no payment, which had already drained the State Treasury of about 5 G$. Despite resolute claims by the Governor that it would not happen, retail tariffs were raised twice by the CPUC, for a total increase of approximately 36% overall, although heavily slanted towards large customers. Because many suppliers are reluctant, or no longer financially able, to sell to the state’s financially crippled institutions (including the CAISO), and because of the declining ability of California to import from rapidly growing and drought inflicted neighbouring states, the supply shortfall was steadily growing.

The spectacular California failure reinforces the case for rational pricing of electricity service such that proper and precise price information is delivered to ultimate customers, preferably in real-time. Customers can then adjust their behavioural pattern of electricity use to reflect its true value, and, more importantly, customer investment decisions regarding purchase of energy using and on-site generating equipment will be appropriate relative to the costs of generating and delivering central station power. Failure to recognise the importance of price response in controlling markets, and the preclusion of accurate pricing through legislated imposition of a price freeze have led to a catastrophic public policy debacle. While under some circumstances interruptible loads can provide a compensating effect to balance the lack of price response, the California experience showed that in the face of serious physical supply restrictions and market difficulties interruptible customers only delivered limited and short-lived relief.

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6. GLOSSARY

AS: *ancillary services*, various classes of back-up generation (or load) available to the CAISO to support system operations, five classes of AS are procured by the CAISO in competitive markets it organises

CAISO: *California Independent System Operator,* the semi-public organisation that operates the California power grid and some energy and ancillary services markets

CalPX: *California Power Exchange*, defunct semi-public organisation that operated the major forward electricity markets and was the SC for the distribution/supply companies

CPUC: *California Public Utilities Commission*, the regulatory agency now overseeing the distribution/supply companies and the generation they control

CTC: *Competitive Transition Charge*, until recently the largest element of customer electricity bills which was recovering stranded assets for the former IOU's
DRP: *Demand Relief Program* of CAISO
ESP: *energy service provider*, independent retail electricity marketer
FERC: *Federal Energy Regulatory Commission*, federal agency now directly responsible for regulating wholesale electricity markets
IE: *imbalance energy*, the electricity purchases by CAISO to match generation and load in real-time
IOU's: *investor owned utilities*, former publicly traded, vertically integrated electricity supply companies
NP15: California *north of Path 15*, a transmission bottleneck that approximately divides the state into two halves
PLP: *Participating Load Program* of CAISO
PG&E: *Pacific Gas and Electric*, the former IOU and now distribution/supply electricity and natural gas utility serving northern California, and one of the biggest utilities in the U.S.
RECLAIM: program of emissions trading in the Los Angeles area
RTC: *RECLAIM Trading Credit*, pollution emission right for the Los Angeles area
SC: S*cheduling Coordinator*, any of about 40 entities authorised to schedule electricity generation, delivery, and consumption schedules with the CAISO
SCAQMD: *South Coast Air Quality Management District,* the authority that regulates stationary sources of pollution in the Los Angeles basin
SCE: *Southern California Edison*, the former IOU and now distribution/supply electricity only utility serving southern California, and one of the biggest electricity utilities in the U.S.
SDG&E: *San Diego Gas and Electric*, the former IOU and now distribution/supply electricity and natural gas utility serving the southwestern corner of California, and much smaller than the other two companies
SP15: California *south of Path 15*, a transmission bottleneck that approximately divides the state into two halves
Stages 1-3: three levels of emergency called by the CAISO when reserves fall to 7, 5, and 1.5% of load, respectively
UDC: *utility distribution company*, electricity distribution/supply companies in Californian regulatory parlance

7. END NOTES

[1] All prices are given in current US$, using SI prefixes, e.g. G = 1 X 10^9. On 15 April 01, US$ 1.0 ≈ _ 1.26.

[2] Description of the CAISO programmes depends heavily on Doudna 2001.