ANALYSIS OF THE POTENTIAL ECONOMIC IMPACTS OF ELECTRIC POWER OUTAGES IN CALIFORNIA

END OF FISCAL YEAR 2001 REPORT

DOE/OCIP Project, Task 2

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Summary

The purpose of this task is to analyze the California electric power supply and demand effects on elements of the state economy as a function of the infrastructure interdependencies.

Analyses were conducted to answer the following questions.

1. What impacts do storage capacity and fuel supply have on the price of electricity and the availability of power on the open market?
2. What limiting factors (e.g., fuel supply, electric power reliability, power costs, regulatory constraints) have the potential to contribute most to an outage based on a single event (or potentially multiple events) in comparison to normal behavior?
3. In each case above, what is the cost of an outage?
   For example:
   - fuel cost to generator
   - power and fuel costs to consumers
   - lost productivity

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As part of this analysis, existing economic modeling efforts have been leveraged. A set of existing interdependency models has been enhanced to allow for the examination of the economic impact and costs of unexpected events in the energy infrastructures. The results of the disruption-scenario economic-effects analysis are documented in this report.

The results of this analysis indicate that shortages of electric power are very likely given California's configuration of generation and anticipated demand. Reliance on natural gas for generation in the service areas south of Path 15 makes this area vulnerable to interruptions in the supply of natural gas.

While attenuation of hydroelectric generation capacity was calculated to have a larger impact in the northern service areas than in those south of Path 15, the hot and dry weather conditions that might limit hydroelectric capacity were also calculated to strain supplies in the south. An increase in winter natural gas demand also increased economic losses relative to the base case, but the effect was much smaller than that seen under the hot, dry summer conditions.

The model of the natural gas storage service tracks the market price for gas, attempting to buy when the price is low and sell when it is high. Expectations about high and low prices are updated based on market prices. Adjusting the offering price until the desired rate is achieved regulates sales rates. The behavior of the storage services creates feedback through the market. This feedback is responsible for some of the more interesting model behavior. Despite significant differences between the simulated and actual prices for natural gas, the modeled storage service did reproduce the tendency to buy and sell inventory in response to seasonal demand changes in the end-use sectors.

In the model, natural gas storage came to be used to smooth seasonal variations in demand. During periods of peak demand, operators of storage services determine the marginal availability and price of natural gas. The increasing reliance on gas-fueled generation tends to increase total demand and decrease the seasonal variations that can be exploited by storage. The limiting factors are import capacity and domestic production, rather than on gas storage volume. An increase in available natural gas storage volume had negligible impact on the calculated shortfalls: the current capacity was never fully exploited in the base case scenario.

Although the uncertainty analysis was not comprehensive, the magnitude of the differences in calculated performance measures between scenarios was generally larger than the uncertainty due to the factors explored.

Limited generation capacity is one factor leading to power supply interruptions, however other factors are important as well. North of Path 15, heavy reliance on hydroelectric generation creates vulnerability to weather conditions the reduce generation capacity. Hot, dry conditions would also lead to increased demand, placing further stresses on the system. South of Path 15, the predominance of natural gas generation stresses the existing natural gas transmission and production capacity. Storage has historically been used to mitigate these stresses. Storage is a critical supply during peak demand periods. The total annual utilization rate of natural gas is ultimately constrained by transmission and production capacity. Increased storage does not help this problem.

Infrastructure Interdependency Assessment

The goal of infrastructure interdependency assessment for specific systems or processes is to identify potential consequences of infrastructure disruptions on system performance and prioritize and develop effective mitigation options for the consequences of concern (those with significant magnitude and probability). Figure 1 illustrates the risk-based decision making framework supported by these assessments. In this analysis, existing data and screening models are used to identify the potentially significant factors influencing the magnitude and duration of economic effects as a result of the power generation situation in California.

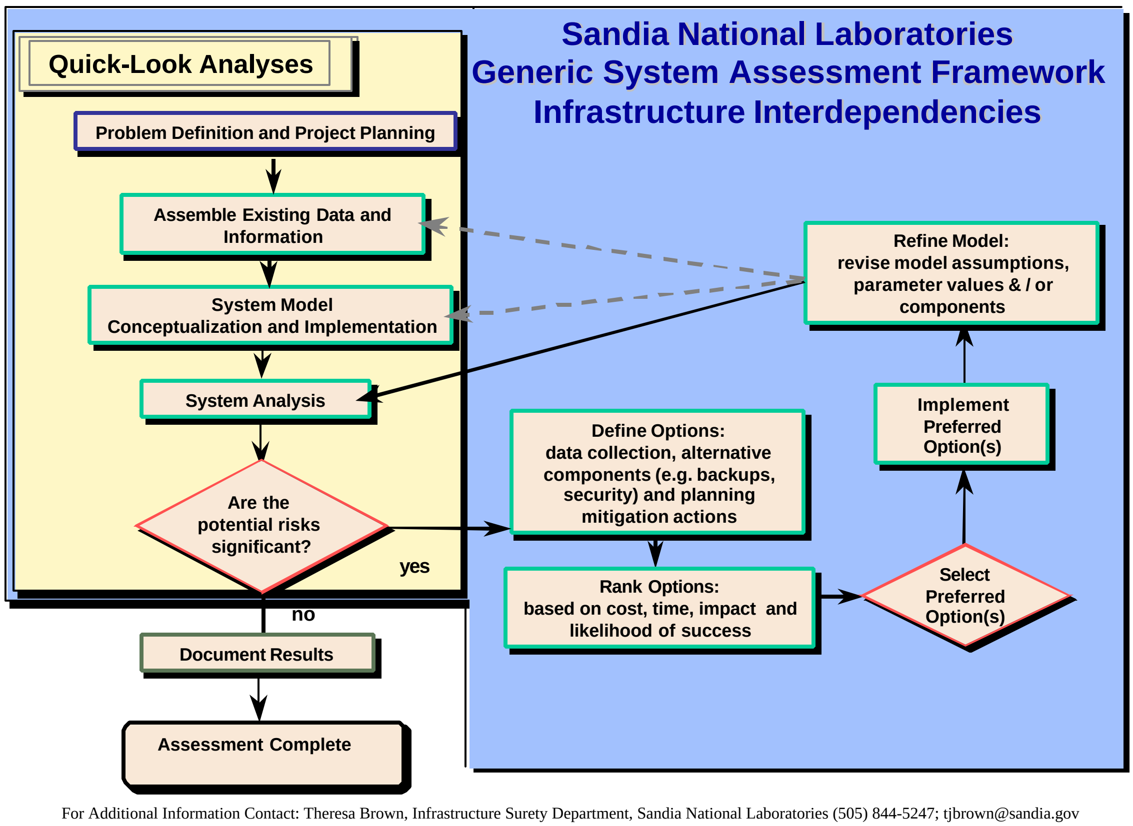

Figure 1: Risk-Based Interdependency Assessment Process

Systems Dynamics Modeling

Infrastructure interconnections create chains of interdependencies that can propagate disturbances across many infrastructures and over long distances. Interdependencies may tend to propagate, amplify or dampen these disturbances. System dynamics modeling is used to simulate the interconnections between California infrastructures and identify chains of interdependencies, which could create unexpected vulnerabilities or robustness. The screening process supported by these simulations also provides the technical justification for additional data collection or model resolution where the uncertainty in the risks make decisions difficult.

This analysis focuses on the potential economic impacts of electric power system disruptions. Within the model used to assess those impacts, the primary tie to the electric power system is through individual system power requirements as a function of the modeled processes and larger-scale system conditions (e.g., climatic conditions). The model is integrated through the models of electric-power supply and demand, with aggregation of data and model elements tied specifically to three electric power service regions: Region A (ISO territory north of Path 15), Region B (areas outside of ISO, e.g. LADWP), and Region C (ISO territory south of Path 15). This aggregation, illustrated on Figure 2, is based on the observed transmission limitations along Path 15.

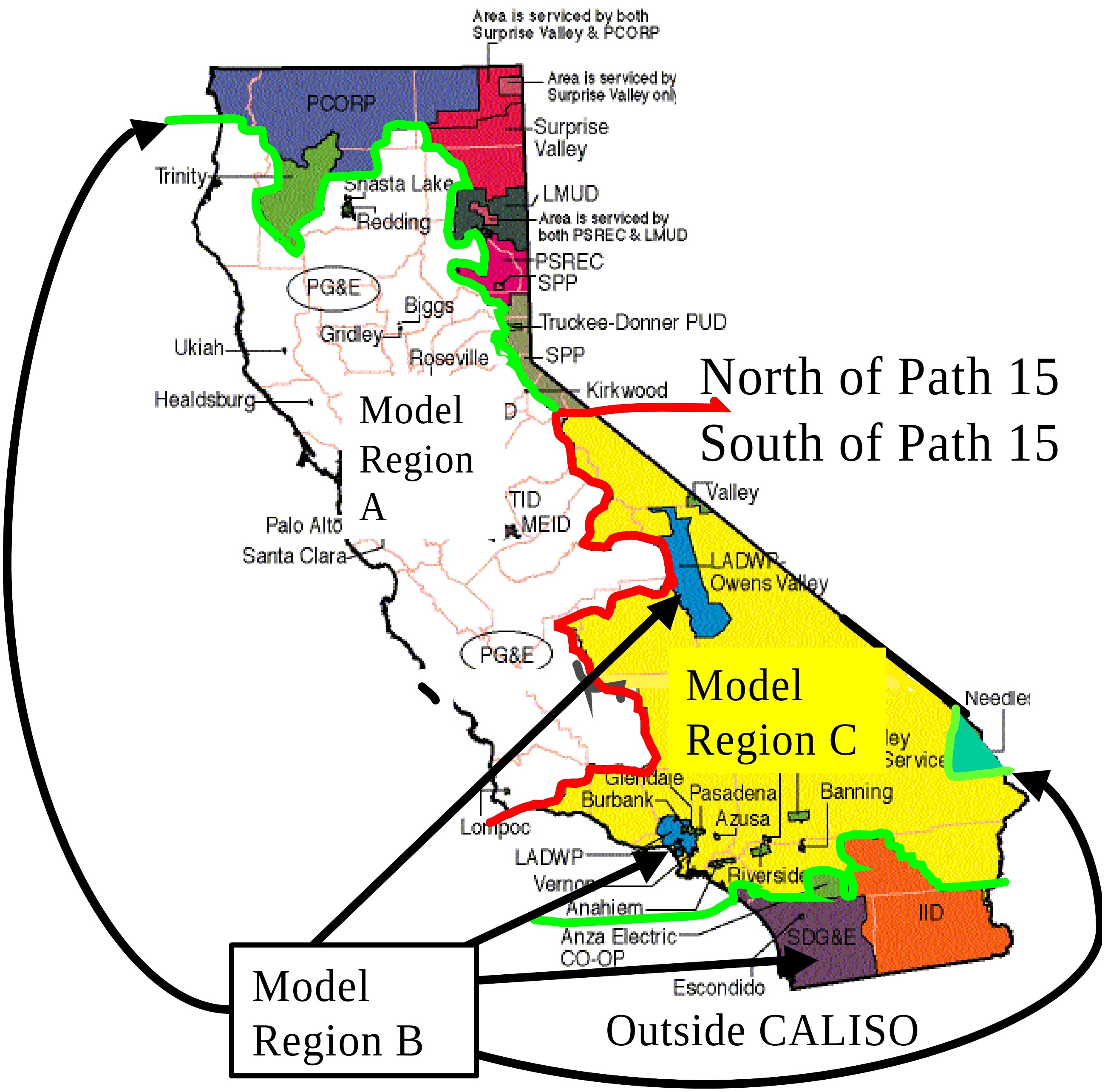

Figure 2: Regions used in the California Infrastructure Interdependency Model (adapted from Cal ISO map of service territory boundaries)

California Infrastructure Interdependency Economic Model

The conceptual model of interacting infrastructures in California is implemented in a set of linked dynamic simulation models. The models are populated with parameter values based on relevant data from open sources. Models have been tested to verify the calculations and stability of model solutions. Key parameter uncertainties have been quantified and evaluated. The details of the California infrastructure interdependency model were documented in the interim report for this task. The interim report is included as an attachment to this report. Parameter values are documented in this report in subsequent sections. The model represents a simplification of the existing system. Due to the small amount of coal generated electric power (less than 550 MW out of 53 GW) it was assumed to be negligible and the interdependencies on coal were not evaluated. The coal generation capacity was not included in the total potential generation capacity for the state. Other fuel sources were lumped in categories (i.e., waste and renewable) and included in the analysis. Costs of obtaining emissions permits, or of paying fines for exceeding them, were not included.

The model configuration includes markets for oil, natural gas, electricity, labor, gasoline, diesel fuel, and water. These markets simulate competitive demand allocation among domestic suppliers and importers. Currently, supply curves are used to model the pricing behavior of suppliers. If power interruptions prevent domestic suppliers from serving the market (because of interruptions to production, delivery, or to their own input supply), then commodity prices rise as the unmet demand shifts to unaffected domestic suppliers and importers. This price rise captures an important part of the possible economic consequences of power interruptions. Although supply curves are useful for matching historical trends and for measuring certain economic consequences of disruptions, they are first-order distillations of complex economic behavior. The dynamics that underlie this behavior, when presented with extreme or novel inputs, might produce responses with important economic consequences that will not be reproduced from supply curves fitted to historical data. The supply curve approximations used in earlier analyses are being replaced with explicit models of the supplier's price setting decision process using profit optimization models. These pricing models provide a better indication of the possible economic responses to the unusual and uncertain environment created by power disruptions. However there are factors that influence pricing, especially in the short term, that cannot be easily formulated in the model. Current prices reflect anticipations about the future, and the specific effects of recurring power disruptions on perceived risk (and therefore on prices) are difficult to anticipate.

Model components incorporated to evaluate the potential impacts of storage capacity and fuel supply on the price of electricity and power availability include California oil and gas producers, refineries, and oil and gas consumers (transportation, agriculture, commercial, industrial, and residential), markets for material exchanges (diesel, gasoline, electric power), gasoline and diesel storage. The model parameter values are based on data aggregated to represent the conditions within the three California electric power regions.

Model services without market representations (e.g., agriculture, transportation), are included in the model as consumers of materials that have a projected demand rate for California material goods as a function of environmental conditions. Material price and availability control the how the demand is met (California vs. external supplies). In this analysis, demand in all sectors is assumed to be inelastic within a given scenario. This assumption could be relaxed by defining a demand function for the end-use sectors. The demand function might be limited to price information, or might be more general. Overall national economic conditions influence demand for energy as well as for California production. The modeled potential economic effects of commodity shortages are limited to the effects of the cost for materials and do not reflect the potential market consequences for these services (e.g., loss of market share to external suppliers).

Analysis Results

Infrastructure Interdependency Model

The model represents the interactions of several infrastructures, including electric power, natural gas, water supply, crude oil, and motor fuels. In general these infrastructures have multiple interconnections created by the use of one commodity (e.g. water) in the production or transportation of another (e.g. electricity). In a particular system of infrastructures some interconnections will be more important than the rest, in that they operate at or near their physical limits, and changes in their operation can have widespread influences. The specific features of that system determine the connections that can constrain a given system. Identifying constraints is one of the primary purposes of interdependency analysis.

In the California model, the availability and price of electric power have a great dependence on the availability and price of natural gas. This dependency arises from the heavy reliance on natural gas generation within the state, the high utilization of available generation capacity to meet demand, and limited capacity to import electric power into the state over existing transmission lines. Electric power availability is also sensitive to weather conditions due to the reliance on hydroelectric generation in the region north of Path 15.

Economic Model

The physical capacities of the various infrastructure elements are the foundation of the Infrastructure Interdependency Model. Within these physical constraints, the utilization of this capacity determines which parts of the system may be stressed under both normal and unexpected conditions. Economic elements of the model help to define how infrastructure utilization changes over time, and in response to hypothesized conditions evaluated using a series of scenarios.

The model is driven by demand for electricity, water, and motor fuels in five economic sectors: agriculture, industry, residential, commercial, and transportation. Nominal demand rates were based on historical data and short-term projections of demand under various scenarios defined by weather conditions. Demand for all commodities was assumed to be inelastic. Within each sector, the commodities were assumed to be complementary: limitations on the supply of one commodity created proportional reductions in the demand for other commodities.

Each commodity is obtained from a competitive market. Regional markets were defined for electricity, water, and natural gas, because the distribution of these commodities is controlled by regional utilities. Statewide markets were defined for gasoline, diesel fuel, and crude oil (demanded by refineries but not by the five end-use sectors). In a given market, all customers pay the same unit price for the commodity. Individual suppliers set their prices independently, and the market model seeks to allocate total demand among potential suppliers in a way that minimizes total cost. Suppliers offering at higher prices will tend to lose share to lower-priced suppliers. Suppliers typically lower prices as demand drops, and increase prices as demand increases. The combination of share reallocation by the market and demand-dependent pricing by the suppliers nominally leads to an equilibrium condition in which all suppliers sell at a common price. Equilibrium will not be achieved if some suppliers reach production capacity limits. Equilibrium can be disrupted by sudden changes in demand or supply conditions.

The pricing behavior for most suppliers is modeled using a supply curve. The reference price and reference supply amount are based on historical market performance, where the relevant data is available. Because the operating costs for gas-fueled generators strongly depend on the price of natural gas, and because natural gas prices are calculated in the model, gas-fueled generators price electricity based on expected marginal cost recovery. The services that provide storage for natural gas, gasoline, and diesel also use a more sophisticated price-setting procedure. Storage services track the market price of fuel, and tend to buy when the market price is apparently low and sell when it is apparently high. Conversely, the desired sales rate varies with the market price, and storage services regulate their offering price in order to attract or discourage sales. Because storage services can provide a relatively important fraction of marketed commodities, their offering price can have a strong influence on the market price. Storage services update their estimates of the trading range based on market behavior.

The pricing behavior of storage services contains feedback loops through the commodity market. This feedback is responsible for some of the more interesting dynamical behavior of the economic model. During high demand periods, natural gas imports to California are constrained by pipeline capacity. The market price for gas therefore increases until storage services release rates satisfy residual demand. The increase in market price causes the storage services to increase their estimates of what constitutes “high” and “low” prices. In subsequent periods of high demand, the market price must be raised even higher before gas is released from storage.

High demand for natural gas arises in part from high utilization of gas-fired generators. As gas prices are bid up to coax releases from storage, the marginal costs for gas-generated electricity increase, making gas generation less competitive. When surplus generation is available, gas-fired generators lose market share as their unit prices increase, leading to a decline in demand for natural gas. This leads to a decline in gas prices, which in turn makes gas-fired generation attractive. The subsequent shift to gas generation can again strain gas pipeline transmission capacity.

In the model, the feedbacks and delays that couple natural gas prices to the amount of gas demanded result in periodic spikes in natural gas prices (see Figure 4 below). These spikes are not observed in the historical record, indicating that the model has not captured some elements of the market dynamics. Past experience with gas price increases, during periods of short supply, would presumably condition the estimated marginal costs of gas-fired generators, leading to anticipatory increases in the bid price for electricity. Such increases would deter the shift to gas-fired generation, somewhat forestalling the anticipated gas supply shortfall. Competition among gas storage facilities, an unwillingness to encourage new entrants or price controls, as well as any joint ownership interests between storage facility operators and their customers tend to moderate gas price increases well below those seen in the model. A more sophisticated model of price setting behavior would be needed to represent these effects.

Although observed natural gas prices do not show periodic spikes, the physical constraints that lead to price spikes in the model are a real feature of the infrastructures in California, and may have ramifications for electric power supply and pricing. Natural gas import rates cannot meet peak seasonal demand, so that storage facilities determine the marginal availability and price of gas. The relative importance of natural gas generation in California, and the limited ability to import gas during periods of high demand, are structural features of California’s power supply systems. These features have the potential to confer market power on the operators of gas storage facilities. As overall demand for gas increases, gas import and production capacities, rather than storage volumes, become limiting factors.

California Data

Public data sources were used to define the critical model input parameters. Relevant Energy Information Administration (EIA) periodicals (e.g. Natural Gas Monthly) were used whenever possible. These publications provide a uniform set of data for each state: developing model parameters from these sources makes it easier to extend or transfer the current model to other states or regions. Where relevant data is not published by the EIA, or when a finer space or time resolution was needed, data from the California Energy Commission (CEC), California Independent System Operator (Cal ISO), Minerals Management Service (MMS), California Division of Oil, Gas, and Geothermal Resources, as well as from other state and federal agencies, was used. Specific sources for the primary model parameters are described below.

In many cases, data with both the appropriate time resolution and the appropriate spatial resolution could not be found in public sources. In these cases, data sources at a coarse resolution were disaggregated to obtain estimates at the desired resolution. For example, monthly data on the sales of motor fuels in California as a whole are published in EIA's Energy Outlook for California. The CEC provides gasoline and diesel sales for California counties in 1998, allowing the monthly EIA data to be disaggregated by county. Annual sectoral consumption rates are available for the entire state from the EIA's State Energy Data report. Monthly consumption by each sector in each county was estimated by assuming that regional, sectoral, and monthly variations in consumption were independent. Disaggregation inevitably requires some such assumption to be made, and the resulting time series have some uncertainty as a result.

End-use Consumption

The model is driven by consumption rates of electricity, water, natural gas, gasoline, and diesel in five economic sectors (commercial, industrial, residential, transportation, and agriculture) in each of the three regions. Many data sources, having different time scales, regional scales, and sectoral aggregations, were used to estimate these consumption rates. Monthly average consumption rates in each of the three model regions for each sector were estimated from these sources. A three-year time series, from 1999 to 2001, was produced for each combination of region, sector, and commodity. Published data typically allowed estimates through the spring of 2001. Base-case estimates for the remainder of 2001 were based on linear trends in the data, perturbed by the average of the monthly deviations from these linear trends seen in the preceding years. The model includes controls that allow modification of the base-case consumption time series for any commodity in any sector in any region.

Electric Power

Daily average data on electric power consumption is available from Cal ISO, along with information on the day's peak power consumption. Sectoral and regional decompositions of this information are not available. EIA's Electric Power Monthly provides monthly average power consumption data for four economic sectors (residential, commercial, industrial, and other) but does not provide a regional decomposition within the state. DOE Form 826 provides utility sales to each sector by month, however the published data only include a subset of California utilities (LADWP, PG&E, SMUD, and SCE) along with statewide totals. Form 861 reports annual sales for all utilities by sector, but does not include information on monthly variations. Monthly power consumption by each sector in each region was estimated from these sources by:

1. Using the regional annual totals from Form 861 to calculate the annual sales in each region by utilities other than those reported on Form 826,
2. Assuming that the monthly variations in sales in each sector for these utilities followed the pattern of sales by the utilities reported in Form 826

Water

The United States Geological Survey (USGS) publishes annual water-use data by sectors in each county in the US. The most recent report (USGS Circular 1200, 1998) contains totals for 1995. Annual totals for 1990 and 1985 are also available. These data were used to calculate per-capita water use rates in each region in each sector for 1985, 1990, and 1995. Trends in the per-capita use rates, and population figures from the 2000 census, were then used to estimate annual consumption rates for 1999 through 2001. Data on monthly variations in water use in each sector were not found. The model is designed so that variations in water use are defined by specifying the month of maximum use, the month of minimum use, and the range of usage rates for each sector in each region.

Natural Gas

Statewide total monthly natural gas consumption rates by each sector are published by EIA in the Natural Gas Monthly. EIA Form 176 reports annual sales to each sector by each natural gas utility. The areas served by these utilities were then used to estimate the fraction of total sales to each sector in each of the three model regions. These regional allocation factors were then used to disaggregate the statewide sales figures reported in the Natural Gas Monthly. In this process, the monthly variations in gas use in each sector are assumed to be the same in each region.

Motor Fuels

Statewide monthly sales of motor fuels are reported in EIA's Petroleum Marketing Monthly. Sectoral information is not available for the monthly data, but annual fuel consumption in each sector is reported in EIA's State Energy Data Report for 1999. The sectoral consumption figures were used to disaggregate the monthly data from the Petroleum Marketing Monthly. Total gasoline consumption in each county in 1998 has been reported by the CEC. These consumption figures were used to disaggregate the monthly time series for each sector.

Commodity Supply

Commodity demand is ultimately satisfied by a combination of internal production, storage depletion, and importation. Data sources for domestic production capacity, and for import capacity limits (where relevant) are described below for each commodity.

Electric Power

Generator data is available from several sources, including EIA, NERC, and CEC. While these databases are broadly consistent, they differ in structure, in the number of generators reported, and in the type and amount of ancillary information provided. Current available generation capacity for each fuel source and each model region was calculated by summing on-line generator capacities reported by the CEC. Service area information in the database was used to assign each generator to one of the three model regions.

Limits on electrical imports into California are another important constraint. Transmission limits on importation and inter-region transfer were imposed using the proposed operating transfer capabilities cited by the CEC in their report on “High Temperatures and Electricity Demand”.

Water

All water use in California was assumed to be provided by domestic surface-water and ground-water sources. Supplying this water requires significant use of electric power. Power requirements depend on the hydraulic head difference between the water source and the supply system inlet. The hydraulic head in the water supply can decline, and the unit power requirements increase, in response to past pumping and climatic effects. The model includes these influences, but does not directly limit the potential supply of water. Instead, any limitations on the availability of water would result from interruptions in the power supply to the pumps. The water distribution system is assumed to place no limits on the availability of water.

Natural Gas

A significant amount of the natural gas consumed in California is imported. Historical domestic production rates in Regions A and C, and from Outer Continental Shelf (OCS) production areas were used to define reference supply rates for domestic production. The modeled production rates from these regions were free to deviate from these historical rates, with corresponding deviations in the price charged by each supplier. On-shore production figures were obtained from the California Division of Oil, Gas, and Geothermal Resources Monthly Production Database. Production rates from the Pacific OCS were obtained from the Minerals Management Service (MMS). Due to the relatively short time frame of the model, no limits were placed on gas reservoir volumes.

The capacities of existing pipelines limit imports to each region and exchange rates among regions. Data on receipt capacities were obtained from CEC’s report on “Natural Gas Infrastructure Issues.” PG&E and SolCalGas each operate large natural gas storage fields help buffer seasonal variations in demand. Data on existing storage capacity, and on the limiting rates for injection and withdrawal from these fields, were also obtained from the CEC report.

Motor Fuels

Gasoline sold in California is specially formulated to control emissions, and is primarily produced in in-state refineries. Both the CEC and EIA provide data on the total capacity and production of California refineries. The maximum historical production rates from CEC’s Weekly Fuels Watch were used to establish separate limiting production capacities for gasoline and diesel. The refineries obtain crude from both domestic production and imports. On-shore and OCS historical production rates were obtained from the California Division of Oil, Gas, and Geothermal Resources Monthly Production Database and the MMS, respectively. Oil imports were unconstrained, and allowed to adjust to total demand rates based on prevailing market conditions.

Climatic Condition Scenarios – Uncertainty in Future Conditions

A limited analysis of the potential effects of environmental stresses on the modeled sensitivity of the California power and fuel markets to parameter uncertainties was conducted for 3 separate climatic conditions. These climate scenarios are called the base case, Hot/Dry summer and Cold Winter. Significant power generation limitations were only seen under Hot/Dry summer conditions. Since the current conditions do not indicate significant numbers of outages under normal summer conditions or cold winter conditions, additional analyses were not conducted to evaluate the effects of additional generation capacity and fuel type on those sensitivities. Parameter values representing climatic conditions and the modeled effects on demand are described below.

Base Case

The model parameter values that define commodity demand rates and supply capacity were set to represent nominal climatic conditions. Demand rates for electric power, natural gas, water, and motor fuels were based on extrapolation of trends in the monthly data for 1999 and 2000, with average monthly deviations from those trends superimposed. Initial natural gas storage volumes in each region were based on an estimated statewide storage volume utilization of 83.7% from EIA's Natural Gas Monthly. The total on-line generation capacity reported in the CEC database was assumed to be available.

Major Assumptions

The based case demand rates are plausible but uncertain. The model uses one-day time steps, and the demand rates reflect average behavior over each day. Most of the underlying data sets are based on monthly averages, and so do not include day-to-day demand variations. These variations might have significant effects on infrastructure behavior and reliability. Electricity shortages are almost always due to an inability to meet peak demand, and so the adequacy of generation capacity must be compared to the potential peak demands associated with the average daily demand used in the model. Cal ISO Hourly and peak demand records from April 1998 to April 2001 were used to calculate the historical ratios of peak demand to average monthly demand. The maximum observed value of this ratio was 1.56. Available generation capacity in the model was therefore divided by 1.6 in order to evaluate the ability to meet peak demand given the current average demand.

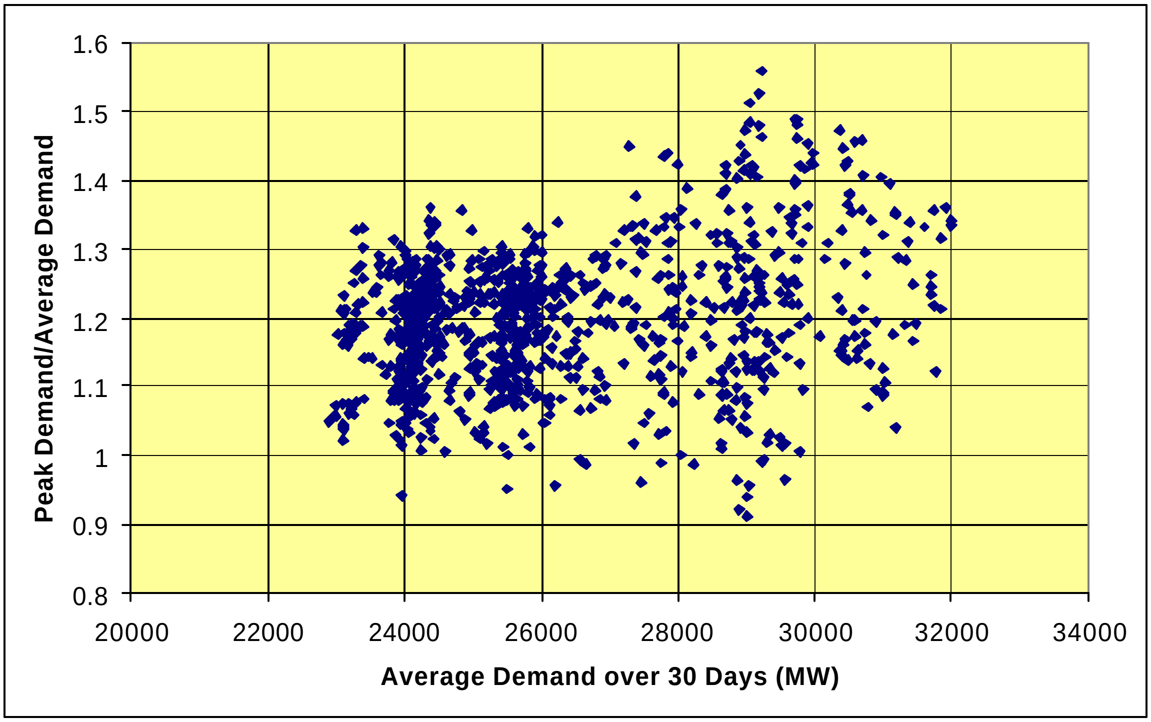

Figure 3: Ratio of daily peak demand in the California ISO to average demand over a 30-day period

Result Summary

Economic loss rates in areas outside the ISO are relatively small. Calculated losses to the agricultural and transportation sectors are zero in all regions, reflecting a consistent supply of water and motor fuels. Both the northern and southern regions show periods of commodity supply interruption sometime during the winter months. In addition, the southern region shows large losses during the fall of 2000 and in the summer and fall of 2001.

Hot/Dry Summer Conditions

The model parameter values were set to represent commodity demand rates and supply capacities that might have resulted if the summers of 2000 and 2001 were hot and dry. A 1999 CEC report on "High Temperature and Electricity Demand" forecasts an 8.5% increase in peak load for their 1-in-40 high temperature scenario. This increase was applied to the base-case electricity demand. The capacities of hydroelectric generators under this scenario were reduced to 70% of their base-case capacities. The maximum import rate into northern California along Path 66 was also restricted to 70% of the base-case maximum to reflect high demand and reduced excess generation in Oregon and Washington. Agricultural water demands were increased from their base-case values to the high values recorded in 1999. The base case initial conditions are based on historical data from 1999, and were unchanged in this scenario.

Major Assumptions

In addition to those assumptions used in the base-case calculation, this analysis assumes changes in commodity demands and supply capacities corresponding to the postulated conditions, and there is considerable uncertainty about these projections. Natural changes in daily electricity usage resulting from hot and dry conditions might influence the maximum ratio of peak to average demand. The value of 1.6 used in this analysis would give an optimistic assessment of supply adequacy if the ratio actually increased, or would be pessimistic if the ratio decreased due to natural usage patterns or load shifting in response to expectations of outages.

Result Summary

Hot dry conditions resulted in a substantial increase in calculated economic losses in all regions.

Cold Winter

The model parameter values were set to represent natural gas demand rates corresponding a cold winter. For the base case scenario, natural gas consumption rates for the last half of 2001 were based on the linear trend in the historical data perturbed by the average deviation from that trend in each month. For the cold winter scenario, these rates were forecasted using the upper 95% confidence limit for the fitted historical trend perturbed by the maximum deviation in any previous year. The base case initial conditions are based on historical data from 1999, and were unchanged in this scenario.

Major Assumptions

In addition to those assumptions used in the base-case calculation, this scenario uses an augmented natural gas demand in all sectors as the most significant consequence of cold winter weather. The increased demand rates were based on analysis of the time series of demand for 1999 and 2000. In contrast to the demand and supply changes estimated for the hot summer conditions in the preceding scenario, these rates do not result from an analysis of the correlated effects of weather conditions with a specified likelihood of occurring.

Result Summary

The cold winter scenario calculations show a smaller economic impact. The calculated increase in economic losses is more pronounced in Region C, which is heavily reliant on natural gas generation, than in Regions A or B.

Natural Gas Pipeline loss

The model parameter values were set to represent loss of import capacity to the southern region on the Kern River pipeline. The total import capacity into the southern region was reduced by 700 MMcfd in this scenario.

Major Assumptions

This scenario introduces no additional assumptions to the base case scenario. Initial conditions were unchanged.

Result Summary

Estimated losses are much larger than in the Cold Winter scenario. Losses in Region C are more than double the losses under the base case assumptions, and Region A is also significantly affected.

Model Uncertainty Analysis

The scope of this task did not include a thorough model uncertainty analysis. However, the uncertainties in the models examined in this analysis include the level of aggregation of the end-use sector models, and behavior representation (response of markets and natural gas generators to economic conditions).

The uncertainties were evaluated using parametric variations within the current models. These variations reflect possible responses of alternative or more detailed models of particular sub-system components. Changes seen in response to these variations reflect the value of more detailed modeling of these components.

The sectoral models for agriculture, industry, commerce, transportation, and residency represent all individuals in that sector in a given region. Shortfalls between the amount of a commodity demanded and the amount supplied are assumed to degrade that sector's contribution to gross state product (GSP). In the base case, material shortfalls are assumed to be shared by 50% of the individual firms in the sector, and the reduction in GSP contribution is assumed to be proportional to commodity shortfall. These assumption is plausible, but a more detailed model of the commodity uses within the sector, or within representative classes in the sector, would likely lead to a different relationship between commodity shortfall and GSP. More detailed spatial resolution would different (and possibly event-specific) distributions of shortfalls over individual firms. To explore these effects, the base case scenario was run assuming that GSP losses vary with the square of commodity losses, and that material shortfalls are concentrated in 10% of the sector.

Pricing behavior of most services is modeled using a supply curve. The possible effects of more complex models of pricing behavior on the overall results was explored by varying the price elasticity of natural gas generators from the base case value of 1 to a value of 0.5.

In the current configuration, the CA II-E model can be used to evaluate alternative market designs for any of the commodities, e.g. by using a reverse Dutch Auction vs. pay-as-bid and capped vs. uncapped conditions on those market structures. These alternative market structures were not simulated in the current study, however the possible effects of alternative models of the utilities' decision processes were explored by reducing the time to reallocate generation among the various types of generators based on market conditions and performance.

Other model uncertainties and uncertainties regarding changes in behavior or infrastructure evolution can be evaluated by changing the mathematical relationships between model elements. For example, uncertainty in process efficiencies or response to limitations in input material can be represented as step wise responses, linear responses corresponding to trends, non-linear responses (periodic functions) or combinations of these model types (e.g., trends toward new steady-state values).

Parameter Uncertainty Analysis

Uncertainty in the maximum ratio of peak demand to average monthly demand was assessed by re-running the base case scenario using a reduced ratio of 1.5. This ratio is still a plausible given the data, exceeded on only three of the more than 1000 days of record. Differences between the base case results and the results obtained with a lower ratio reflect the potential uncertainty reduction that would be achieved by modeling the system at a time scale that included hourly demand data.

Results

Base Case

Selected results of the base-case simulation are shown in Figures 4 through 8. The prices for electricity in the three model regions, and the state prices for gasoline and diesel fuel, exhibit large fluctuations at the beginning of the simulation as the markets for these commodities achieve an optimum allocation among suppliers. The prices for natural gas continue to show large variations throughout the simulation due to the periodic limitations of supply and the consequent increases in cost. The modeled storage operator forms its expectations about price based on market performance, so that spikes in natural gas prices tend to increased price expectations, leading to larger future spikes when supply is constrained. The three natural gas utilities are assumed to buy from the same statewide wholesale market. Because they confront the same supply conditions the retail natural gas prices in Figure 5 are the same in the three model Regions.

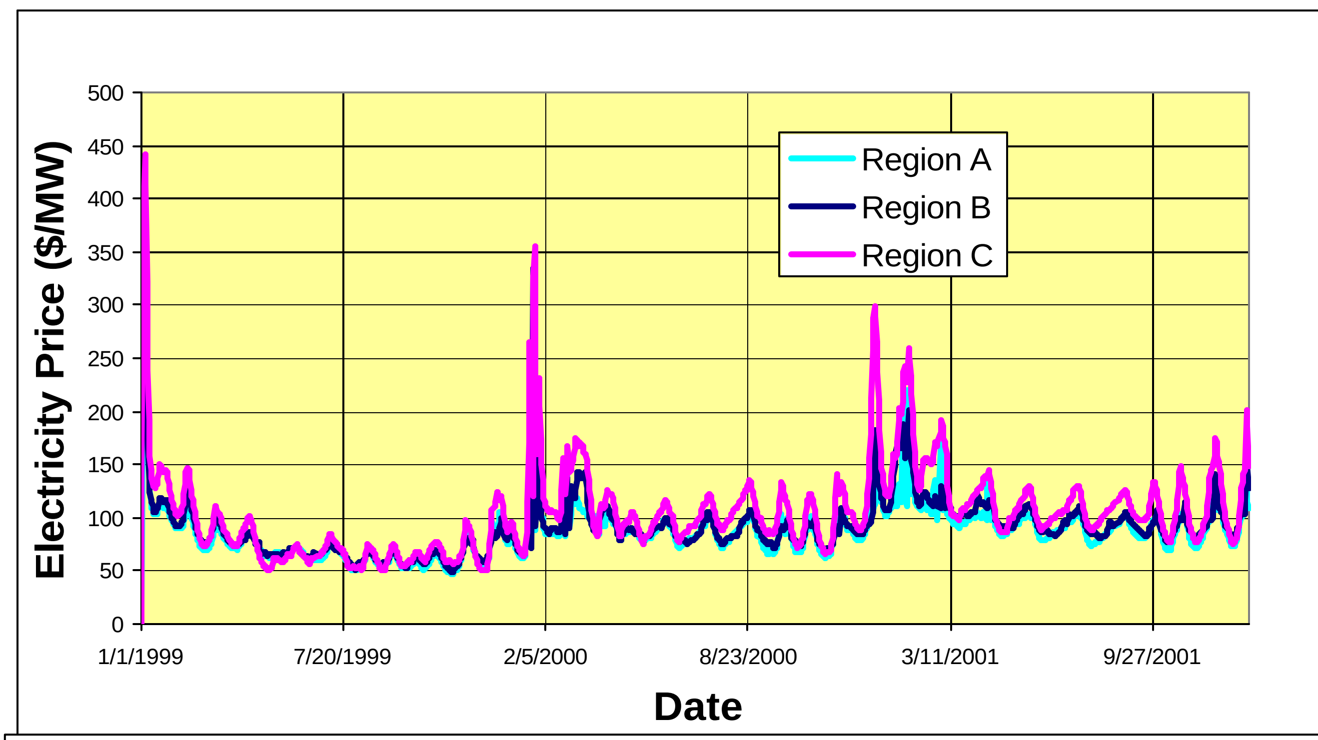

Figure 4 – Modeled Daily Prices for Electric Power in the Three Model Regions – Base Case

(Region A – Cal ISO north of Path 15, Region B – Outside Cal ISO, Region C – Cal ISO south of Path 15)

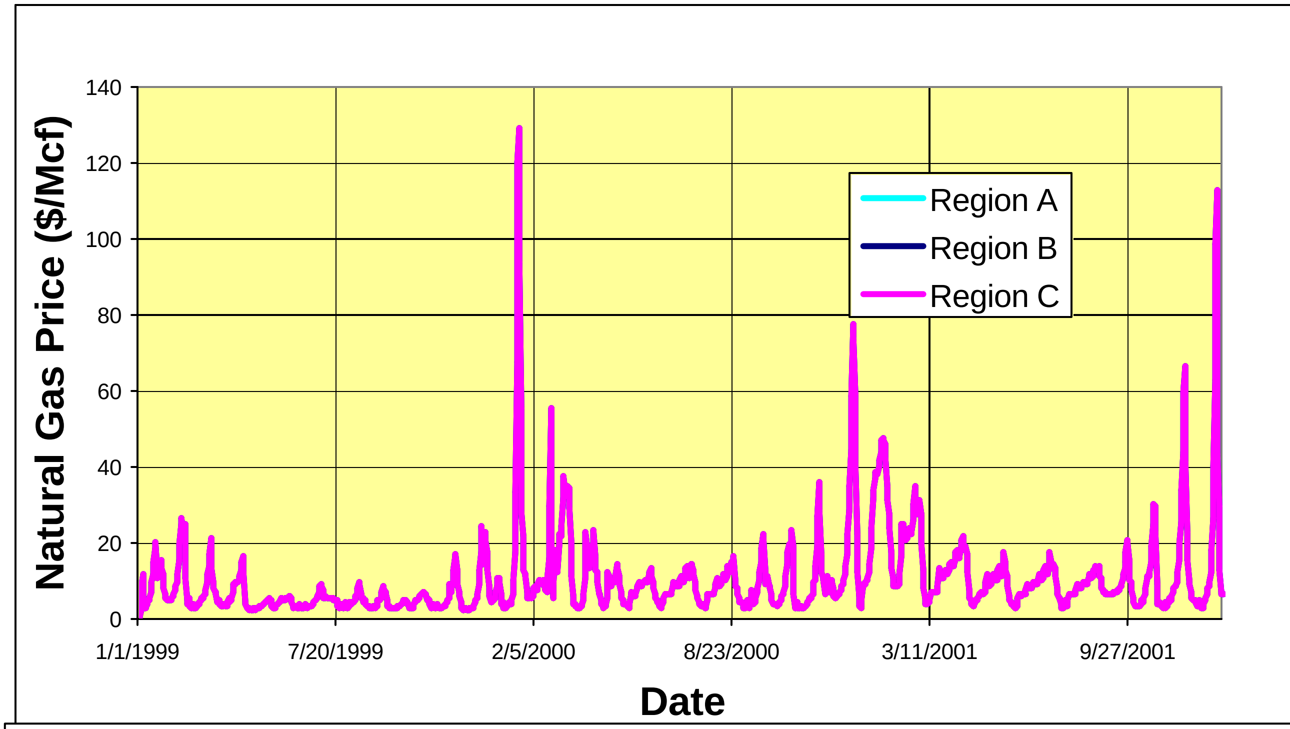

Figure 5 – Modeled Prices for Natural Gas in the Three Model Regions – Base Case

(Region A – Cal ISO north of Path 15, Region B – Outside Cal ISO, Region C – Cal ISO south of Path 15)

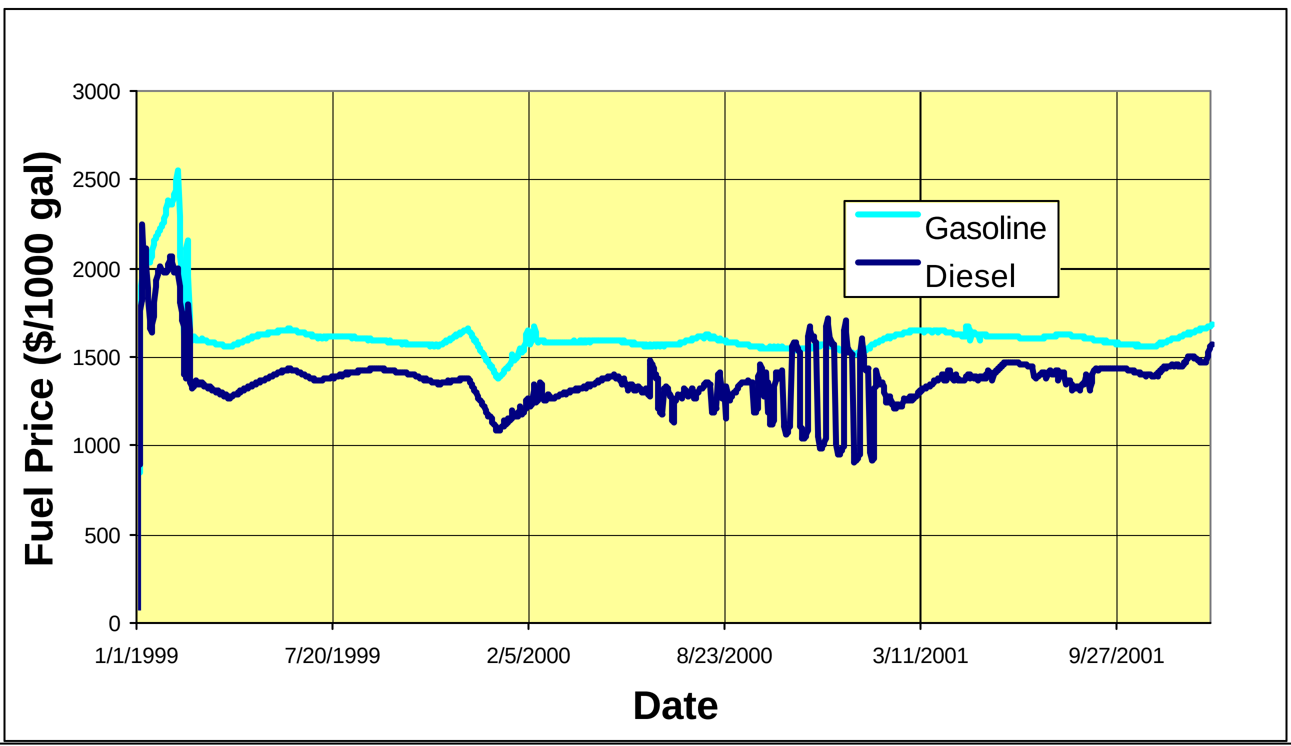

Figure 6 – Modeled Statewide Prices for Motor Fuels – Base Case

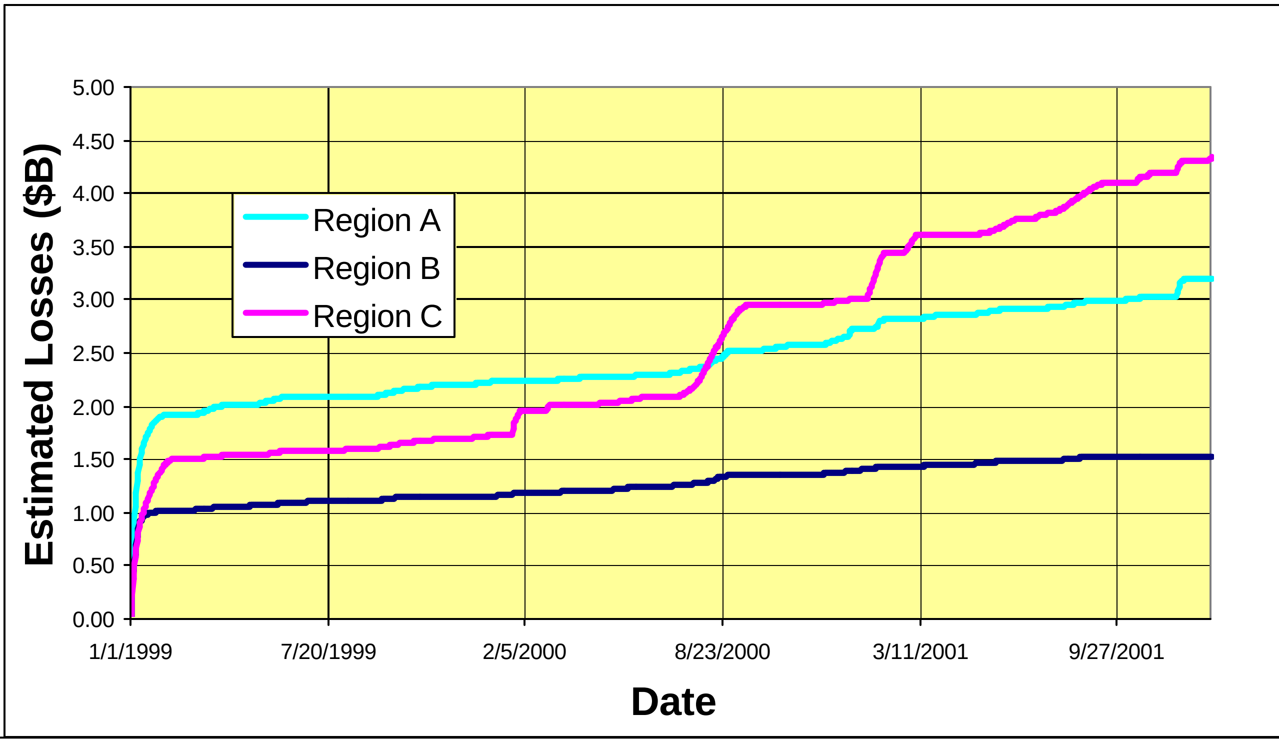

Figure 7 – Modeled Industrial Sector Losses in the Three Model Regions – Base Case

(Region A – Cal ISO north of Path 15, Region B – Outside Cal ISO, Region C – Cal ISO south of Path 15)

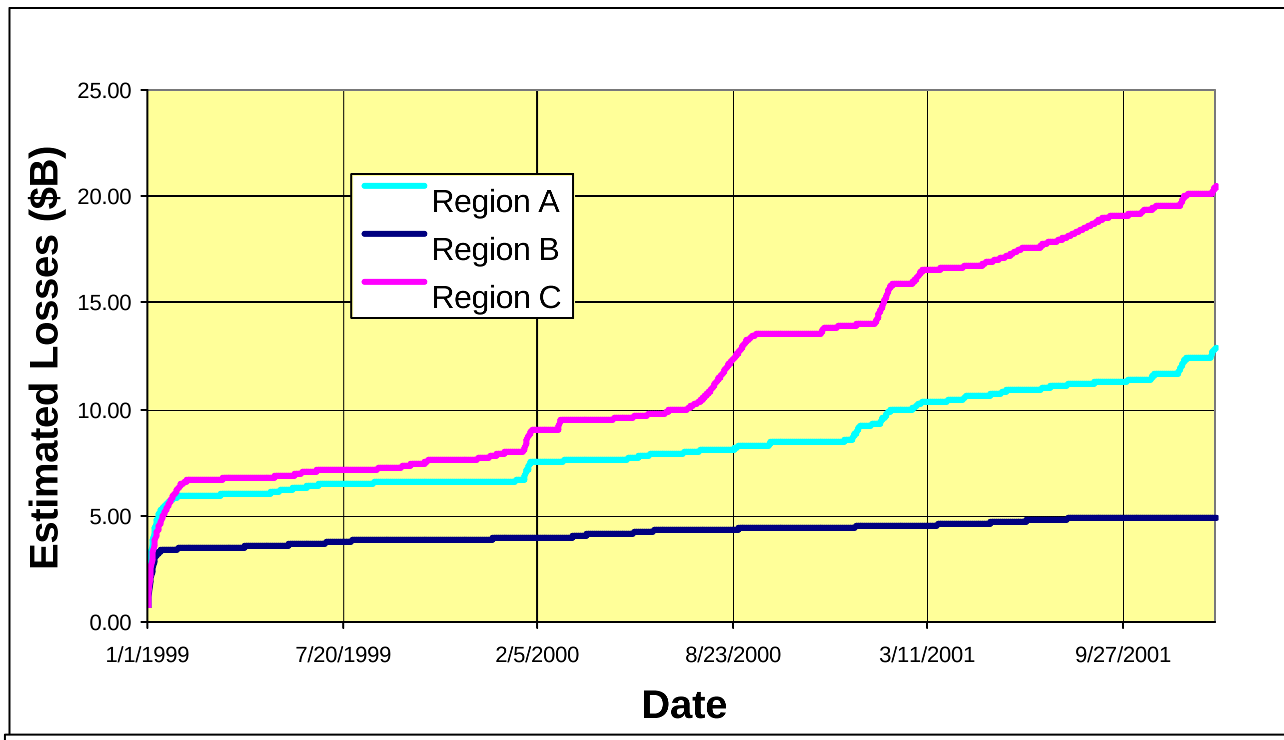

Figure 8 – Modeled Commercial Sector Losses in the Three Model Regions – Base Case

(Region A – Cal ISO north of Path 15, Region B – Outside Cal ISO, Region C – Cal ISO south of Path 15)

The calculated prices for electricity in Figure 4 are somewhat higher in the southern region (Region C) than they are outside the ISO (Region B) and in the northern region (Region A). Prices are more variable in the southern region than in the northern region, and price variations are very closely correlated to natural gas prices, reflecting the predominance of gas generation as a supply source. Although all natural gas generators buy from the same wholesale market, Region C has a larger percentage of gas-fired generators.

After recovering from the initial market disequilibrium, motor fuel prices shown in Figure 6 are quite steady, excepting a period of oscillating diesel prices in the winter of 2000-2001. This oscillation is induced by the diesel storage service, which exploits its market position by constricting supply until additional production is attracted into the market. This additional production sharply reduces the market price. The dynamics of this oscillation are analogous to the behavior of the natural gas storage service discussed above. This behavior is an artifact of the model structure, which places all diesel storage under a single decision maker. Real prices for motor fuels are typically volatile, in contrast to the steady trends seen during most of the simulated period. Real prices are influenced by a number of factors not included in the model, such as fluctuations in demand not captured in the monthly average data, competition for refining capacity among fuel types, OPEC policies, and political unrest.

Economic effects of commodity shortages in the commercial and industrial sectors, shown in Figures 7 and 8, show large loss rates during the initial days of the simulation. These shortfalls are artifacts of the initial market disequilibrium, and do not reflect actual losses due to commodity shortages. Disregarding these initial transient effects, loss rates in areas outside the ISO are relatively small. Calculated losses to the agricultural and transportation sectors are zero in all regions, reflecting a consistent supply of water and motor fuels. Water supply to the agricultural sector was not assumed to be limited by mandated conservation measures. In Figures 7 and 8 both the northern and southern regions show periods of commodity supply interruption sometime during the winter months. In addition, the southern region shows large losses during the fall of 2000 and in the summer and fall of 2001. During these periods, the demand for electricity is calculated to exceed the available generation capacity, as shown in Figure 9 for the southern region.

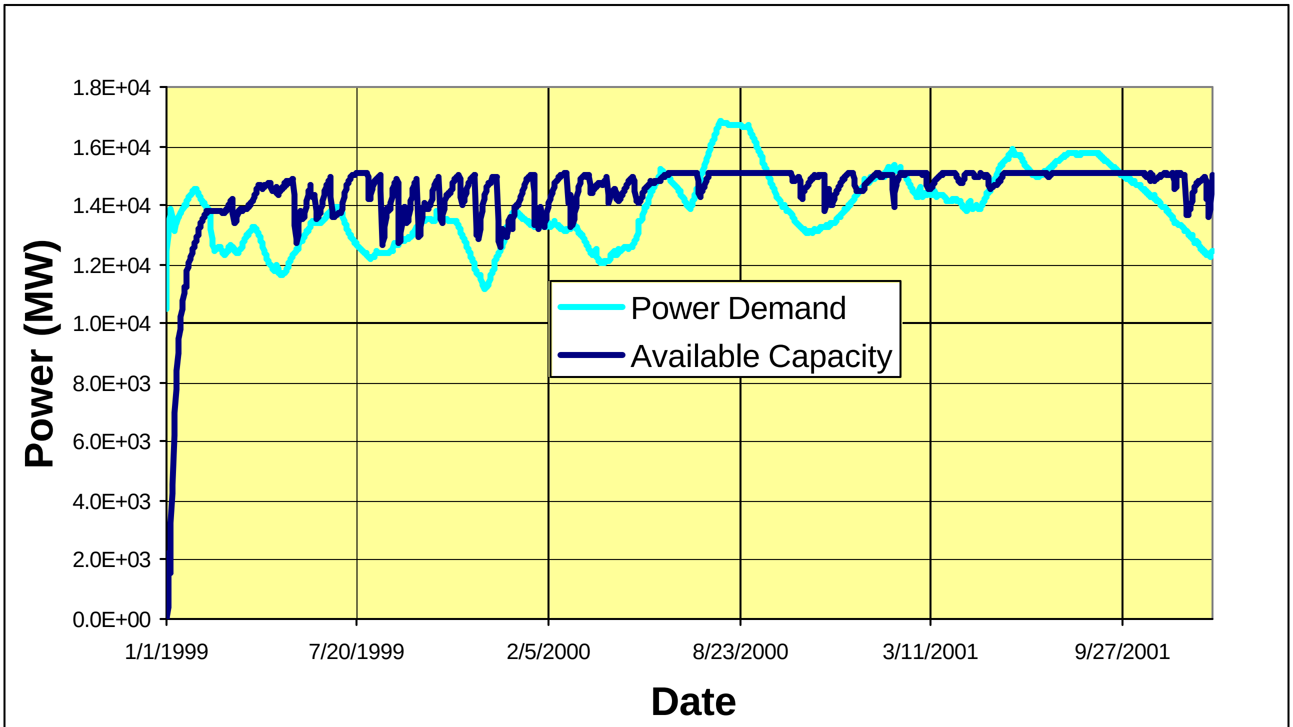

Figure 9 – Modeled Electric Power Demand and Available Supply in Region C – Base Case

Simulated natural gas prices rise at the beginning of the simulation as the wholesale and retail markets seek an initial equilibrium. This price increase prompts a sell-off of stored natural gas. Figure 10 shows the calculated monthly gas storage volume in all regions. Subsequent periods of acquisition and sales suggest a developing annual trend. This result is interesting because the logic governing sales and acquisition only depends on price histories, current inventory, and capacity. Any annual cycles in behavior must derive from periodicity in commodity demand by the end-use sectors, which is conveyed only indirectly to the storage operator via market prices for natural gas. While there is a pronounced seasonal variation in the demand for natural gas by the end-use sectors, as shown in Figure 11,any periodicity in the natural gas prices (Figure 5) is much less evident.

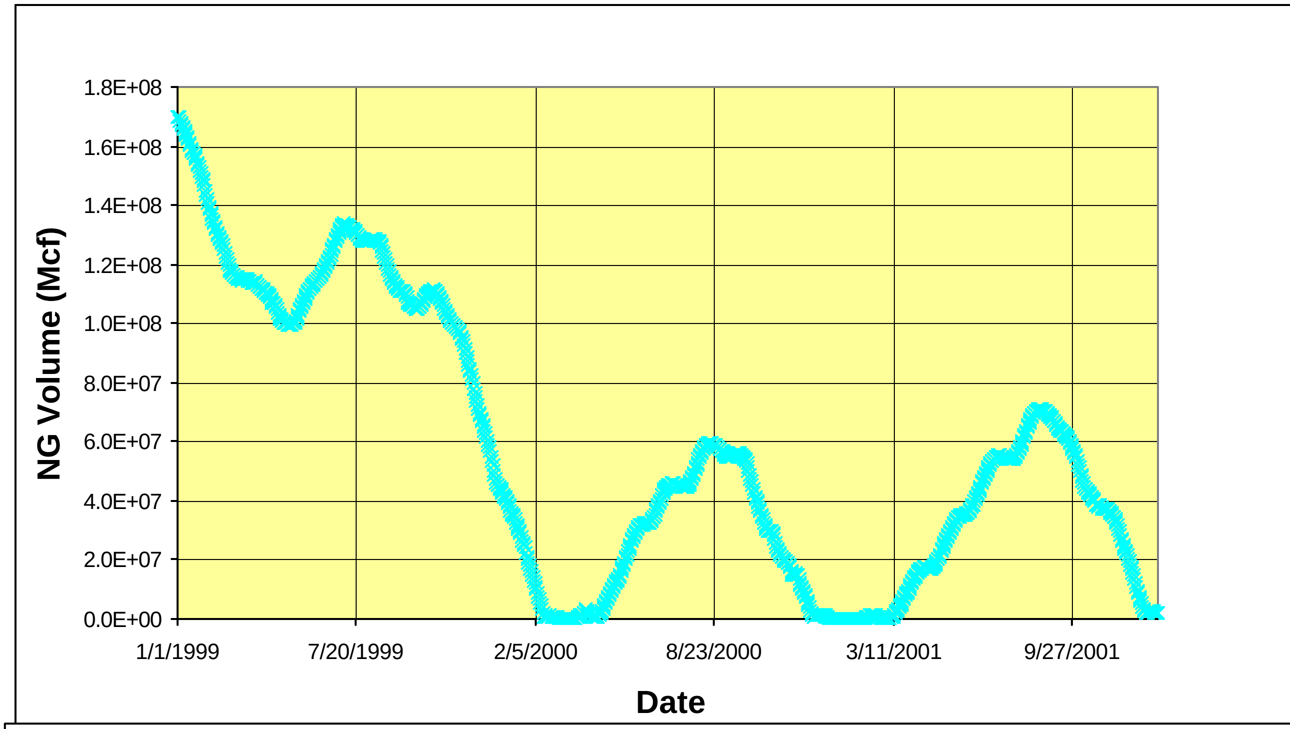

Figure 10 - Calculated Volume of Natural Gas in Storage

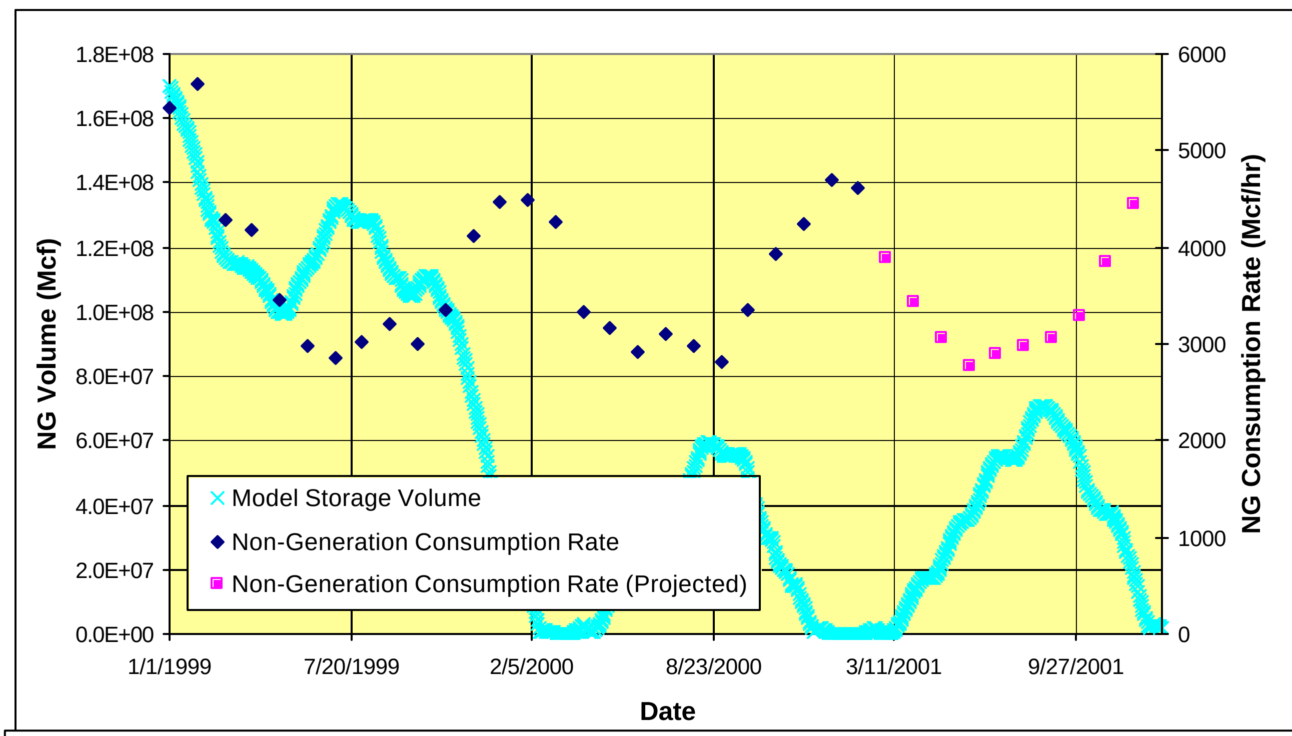

Figure 11 – Countercyclic Behavior in Calculated Natural Gas Storage Volume and Non-Generation Consumption Rate

The observed periodicity in natural gas storage is generally countercyclic to demands in the end-use sectors: storage is depleted when other sectors increase use rates, and is replenished when demand drops. This behavior helps to balance overall natural gas demand, and conforms to changes in storage volumes reported by the EIA. Figure 12 shows the historical changes in natural gas storage along with the results of the base case simulation. Historical trends show a general depletion of storage over the two years of record. The behavior of the simulated storage facility features a pronounced sell-off during the fall and early winter of 2000. Simulated and historical periods of sales and acquisition generally correspond, although the simulation overlooked a buying opportunity in the fall of 1999.

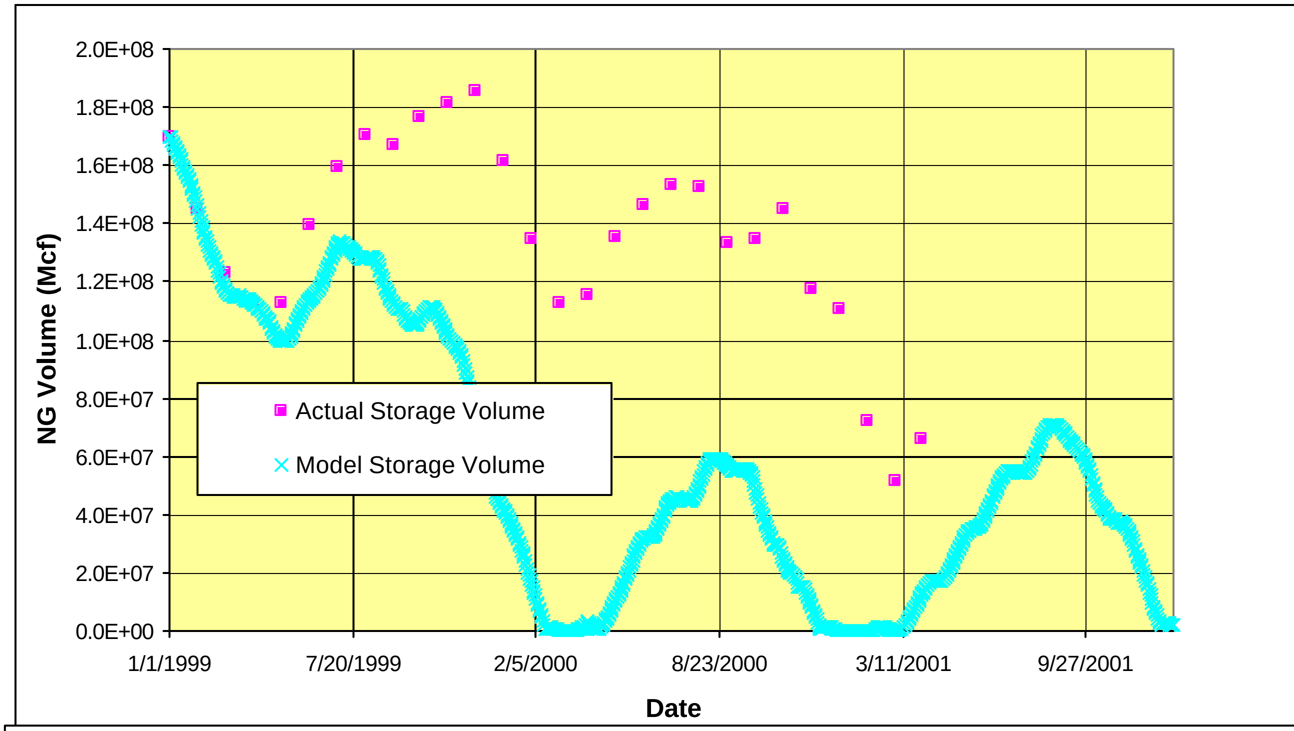

Figure 12 - Calculated and Historical Natural Gas in Storage

Providing additional natural gas storage capacity had no significant effect on any of the model results. In the base case simulation (as in the historical record), current storage capacity was never fully exploited. Although the available capacity is one factor that is considered in the model's sales and acquisition decision process, the effect of the added capacity was not sufficient to make a noticeable change in model behavior because the market conditions never support a period of sustained acquisition.

Model Uncertainty Analysis

Alternative Dependence of End-use Sectors on Supply

The first model uncertainty analysis was focused on estimating the possible effects of refining the models of the end-use sectors. These models might be refined either by refining the regional resolution to distinguish those individual firms that are influenced by commodity shortages from those that are not, or by explicitly modeling representative firms in each sector to better estimate the dependence of commodity flow reliability on the sector's contribution to Gross State Product (GSP). Figure 13 shows the calculated losses in the southern region's commercial sector under the base case assumptions and using the alternative parameter values. The alternative parameter values correspond to a smaller fraction of individual firms experiencing shortfalls, with a larger loss at each firm per unit of unsatisfied demand. Although the timings and extent of power shortfalls are nearly identical in both cases, calculated losses are much larger under the alternative assumption end-use assumption.

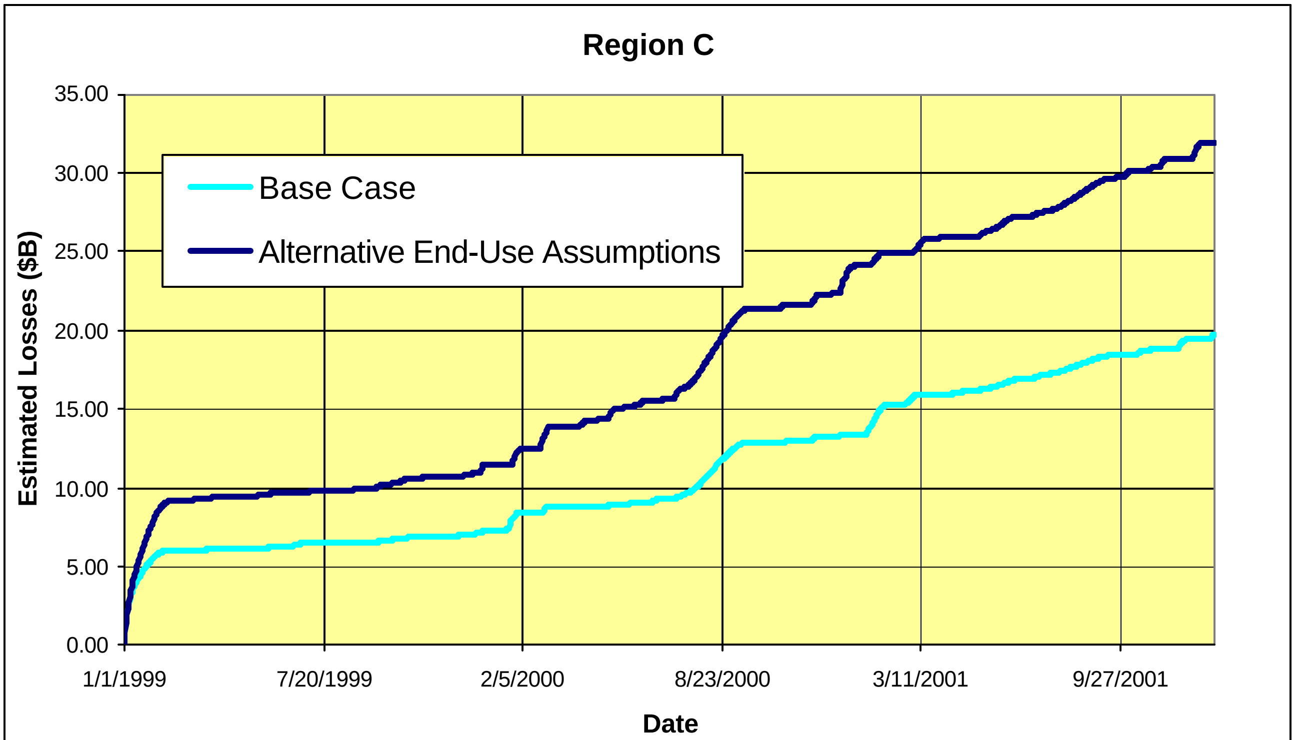

Figure 13 – Modeled Commercial Sector Losses in Cal ISO south of Path 15 – Base Case vs. More Localized Outages

Price Elasticity of Gas-fired Generators

A second analysis explored the possible effects of alternative behavioral assumptions by changing the short-term elasticity of the supply curve for natural gas generators from its base-case value of 1 to a value of 0.5. This change tended to increase the calculated economic losses, as shown in Figure 14. The reduced price elasticity tends to discourage sudden increases in demand from natural gas generators by increasing their price relative to the base case.

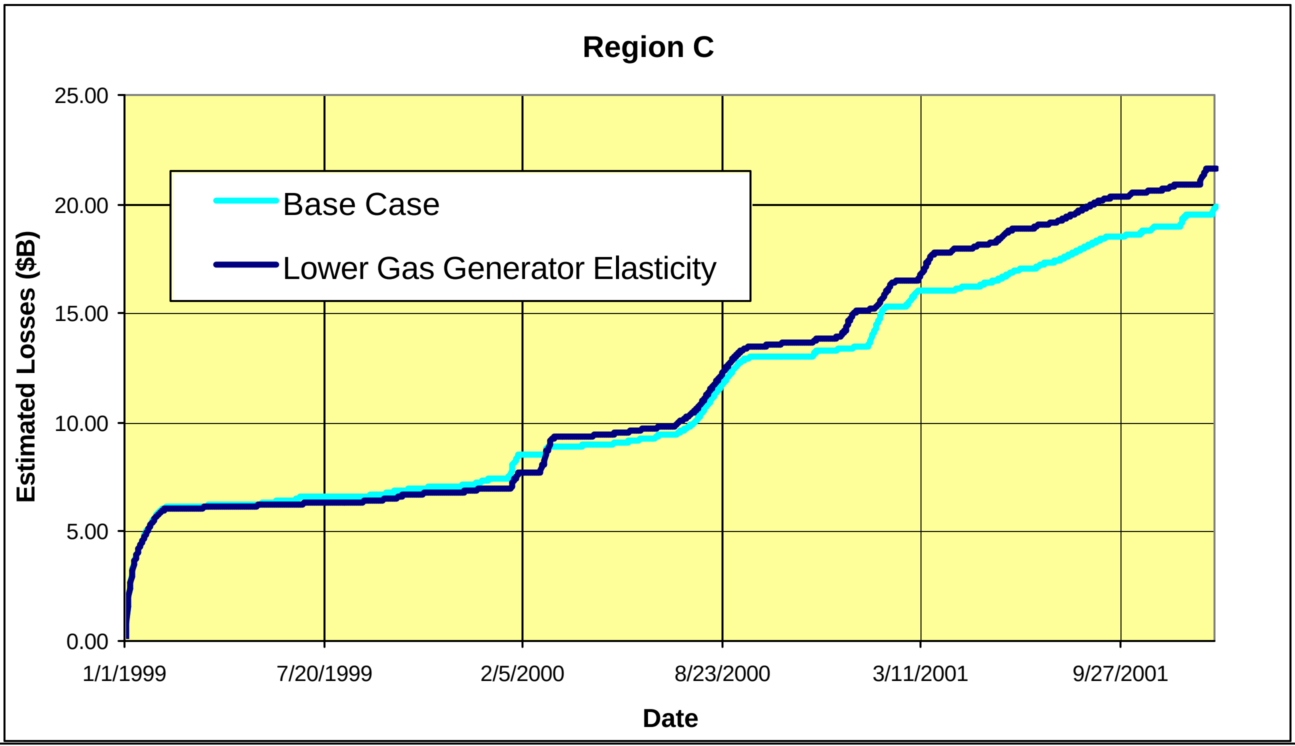

Figure 14 – Modeled Commercial Sector Losses in Cal ISO south of Path 15 – Base Case vs. Alternative Model of Natural Gas Generator Pricing

Market Adjustment Rate

The time required to reallocate market share from one type of generation to another was increased in order to explore the possible effects of alternative models of market decision-making. Calculated economic losses were larger under this assumption, as illustrated by the results for Region C's commercial sector shown in Figure 15. With the ability to reallocate generation more rapidly in the base case, the market can more readily compensate for shortfalls in supply from natural gas generators.

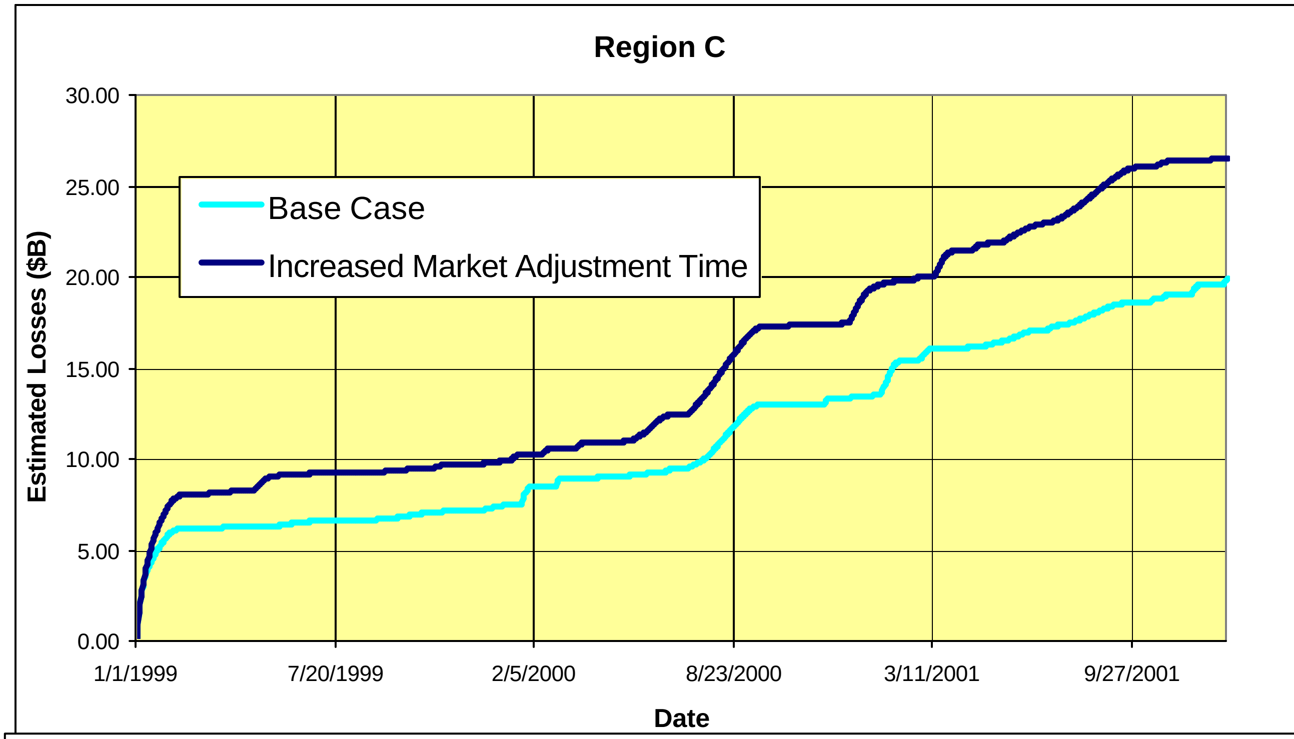

Figure 15 – Modeled Commercial Sector Losses in Cal ISO south of Path 15 – Base Case vs. Longer Adjustment Time for Reallocating Market Shares

Parameter Uncertainty Analysis

Peak/Average Demand Ratio Reduction

The ratio of peak demand to average monthly demand was reduced from the base case value of 1.6 to an alternative value of 1.5 in order to explore the uncertainty introduced by using monthly average power consumption rates to assess generation limitations with respect to peak demand. The resulting estimated economic losses were lower in both regions, with smaller losses due to supply interruptions calculated to occur in the fall of 2000 and in 2001. Figure 16 shows the effect on calculated losses to Region C's commercial sector. This result suggests that simulations including data on hourly load variations would produce different loss estimates, and that load shifting resulting in reduced peaks might be an effective short-term mitigation for current supply constraints.

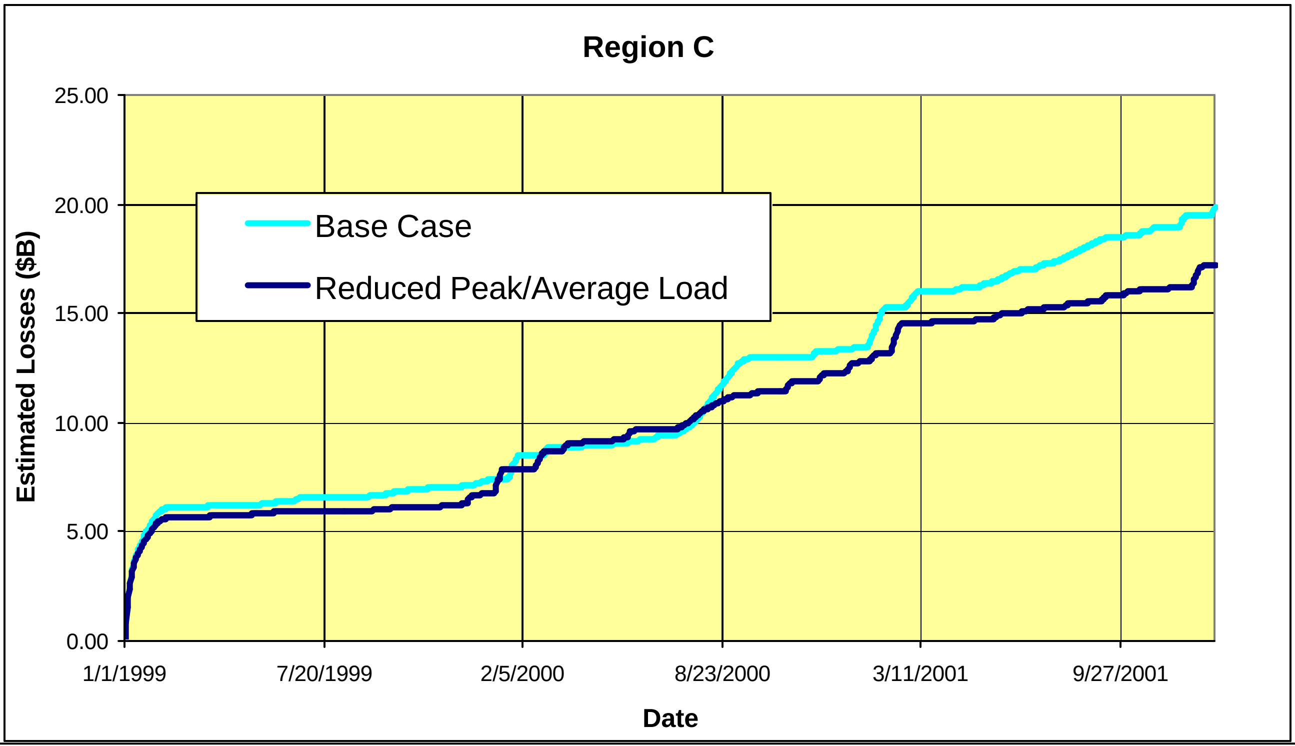

Figure 16 – Modeled Commercial Sector Losses in Cal ISO south of Path 15 – Base Case vs. Decreased Ratio of Peak to Monthly Average Load from 1.6 to 1.5

Scenario Analysis

Hot dry condition in 2000 and 2001 resulted in a substantial increase in calculated economic losses in all regions. Figures 17 and 18 show calculated losses to the commercial sector in Regions A and C. Region A, which is more reliant on hydroelectric generation, experiences a sharp shortfall as this capacity is withdrawn. Both regions show much larger losses due to commodity shortages than in the reference case.

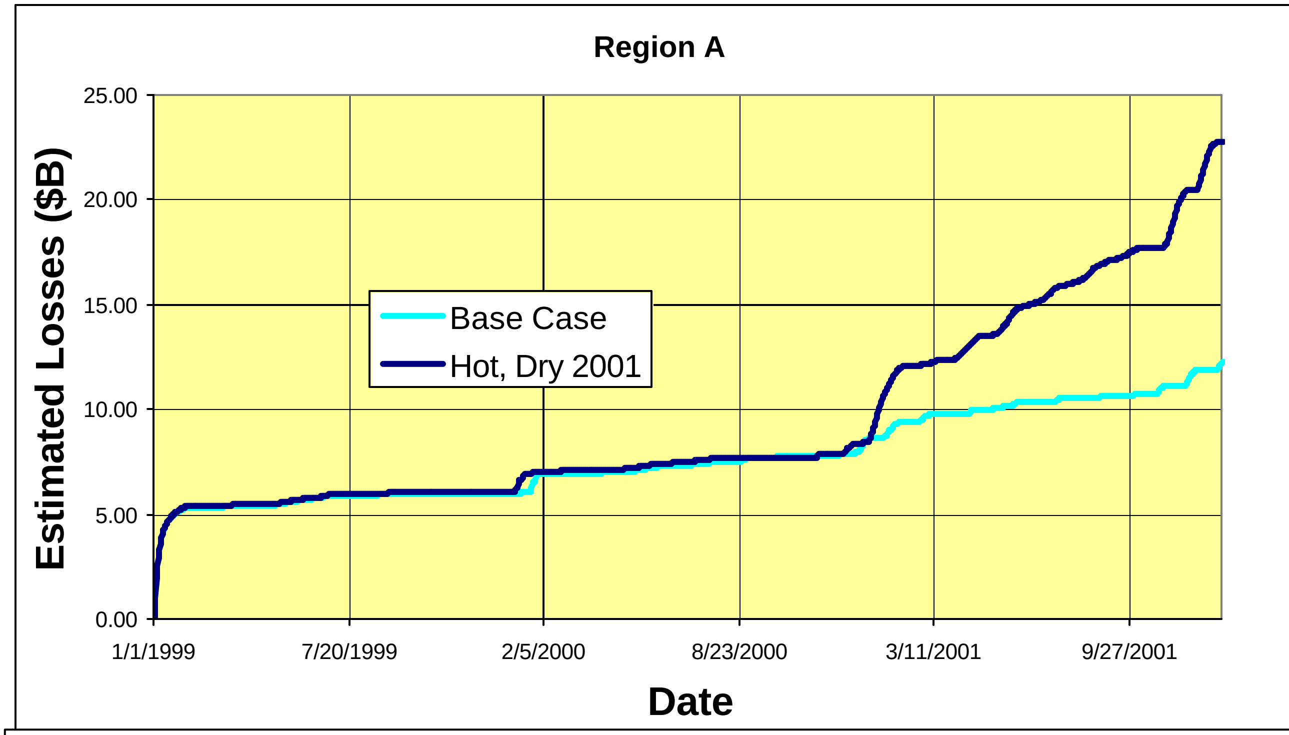

Figure 17 – Modeled Commercial Sector Losses in Cal ISO north of Path 15 – Base Case vs. Hot. Drv Summer Conditions

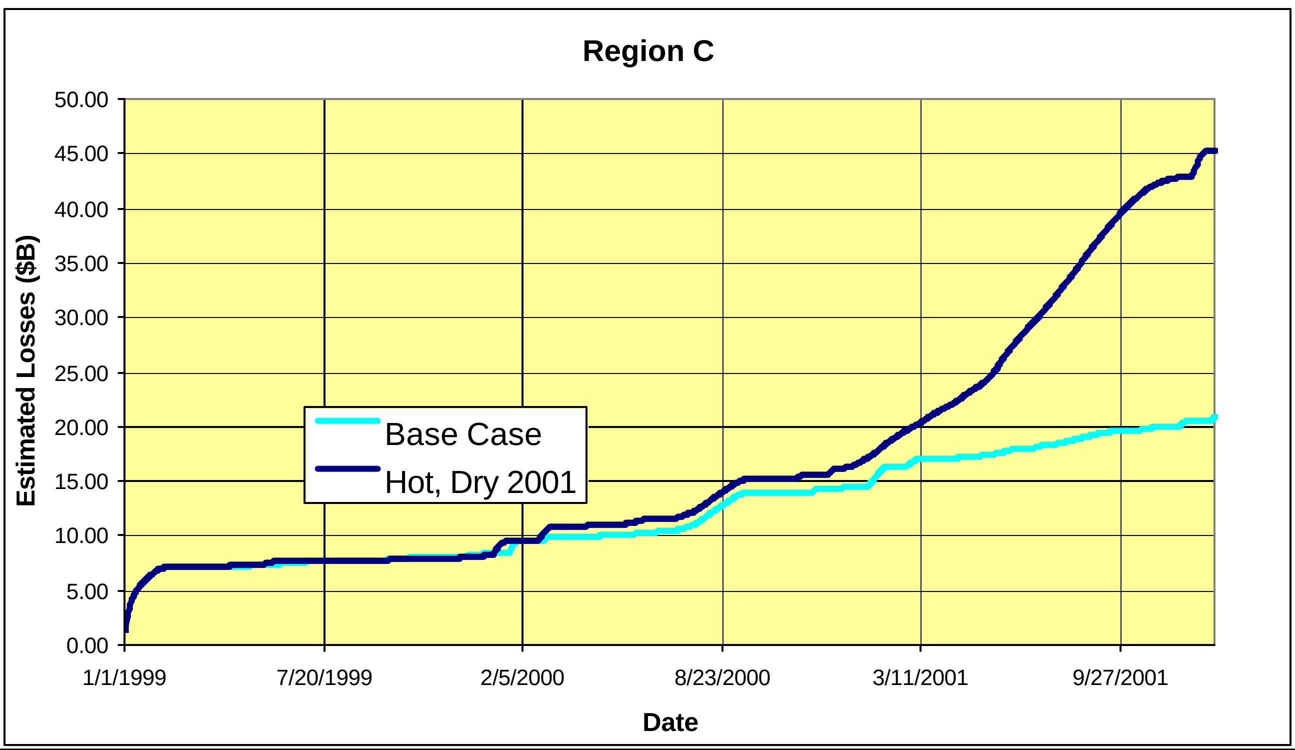

Figure 18 – Modeled Commercial Sector Losses in Cal ISO south of Path 15 – Base Case vs. Hot. Drv Summer Conditions

The cold winter scenario calculations show a smaller impact on economic losses than the hot, dry scenario. Figures 19 and 20 show the estimated commercial sector losses in Regions A and C. The estimated increase in losses is more pronounced in Region C, which is more heavily reliant on natural gas generation.

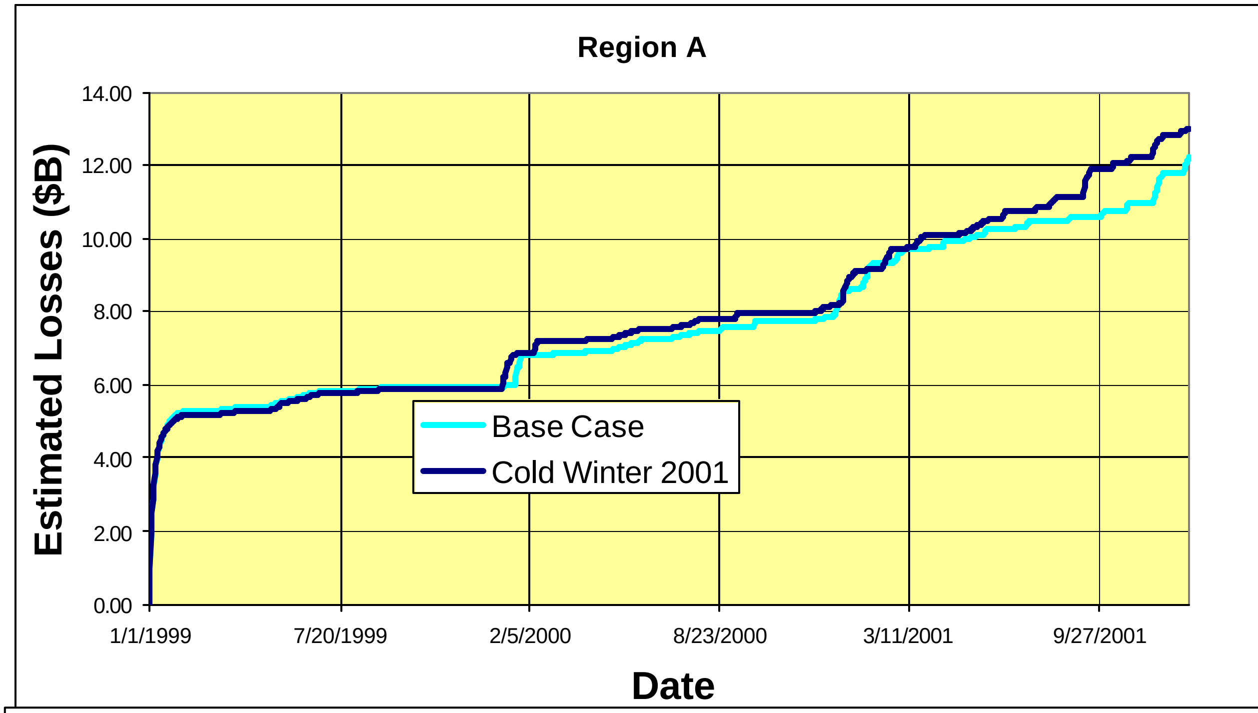

Figure 19 – Modeled Commercial Sector Losses in Cal ISO north of Path 15 – Base Case vs. Cold Conditions in 2001

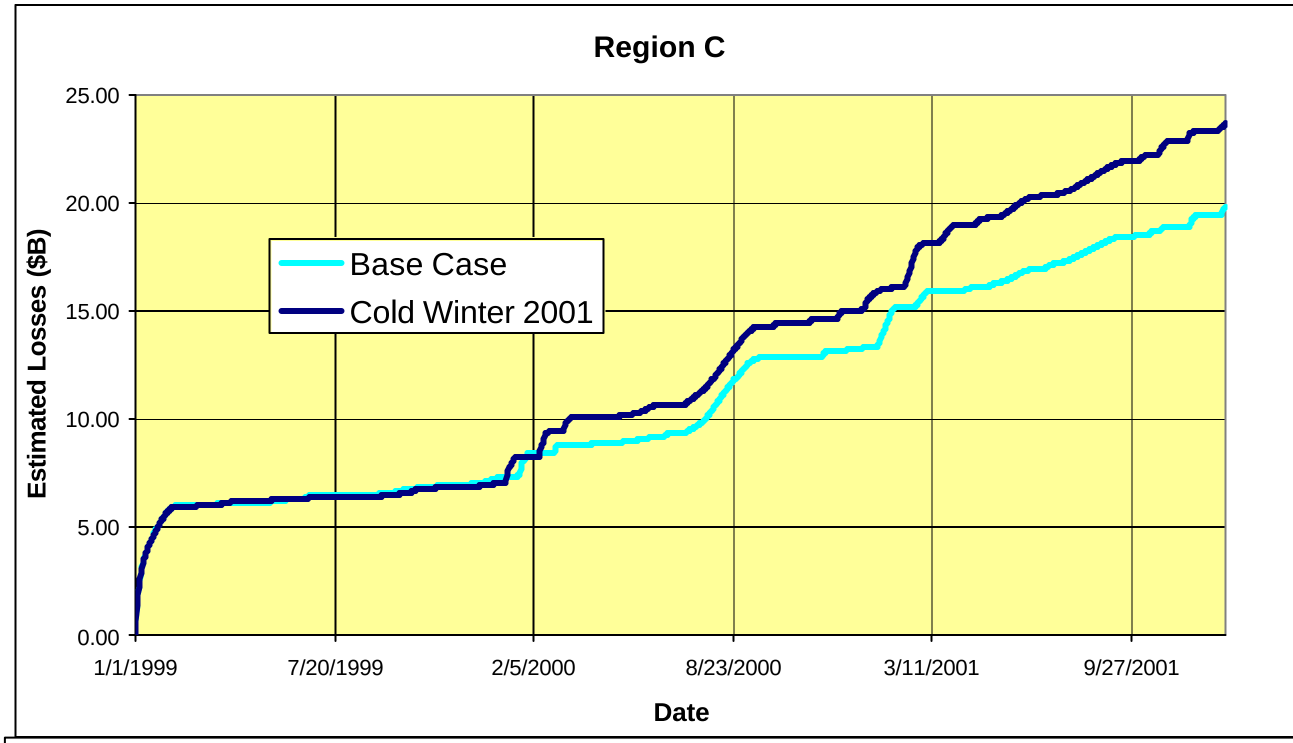

Figure 20 – Modeled Commercial Sector Losses in Cal ISO south of Path 15 – Base Case vs. Cold Conditions in 2001

Region C's reliance on natural gas generation is also seen in the results of the supply interruption scenario. Figures 21 and 22 show the calculated changes in economic loss to the commercial sector in Regions A and C. Estimated losses in Region C are more than double the losses under the base case assumptions, and Region A is also significantly affected.

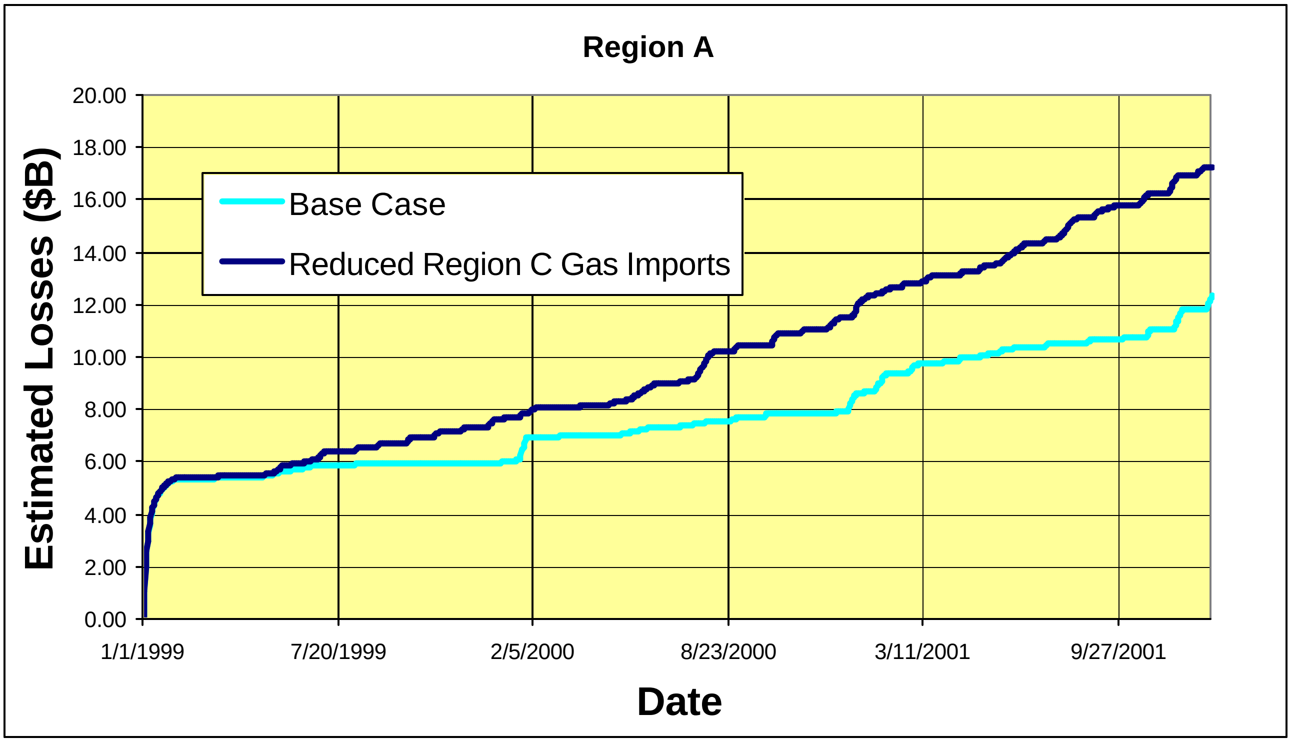

Figure 21 – Modeled Commercial Sector Losses in Cal ISO north of Path 15 – Base Case vs. Reduced Gas Import Capacity

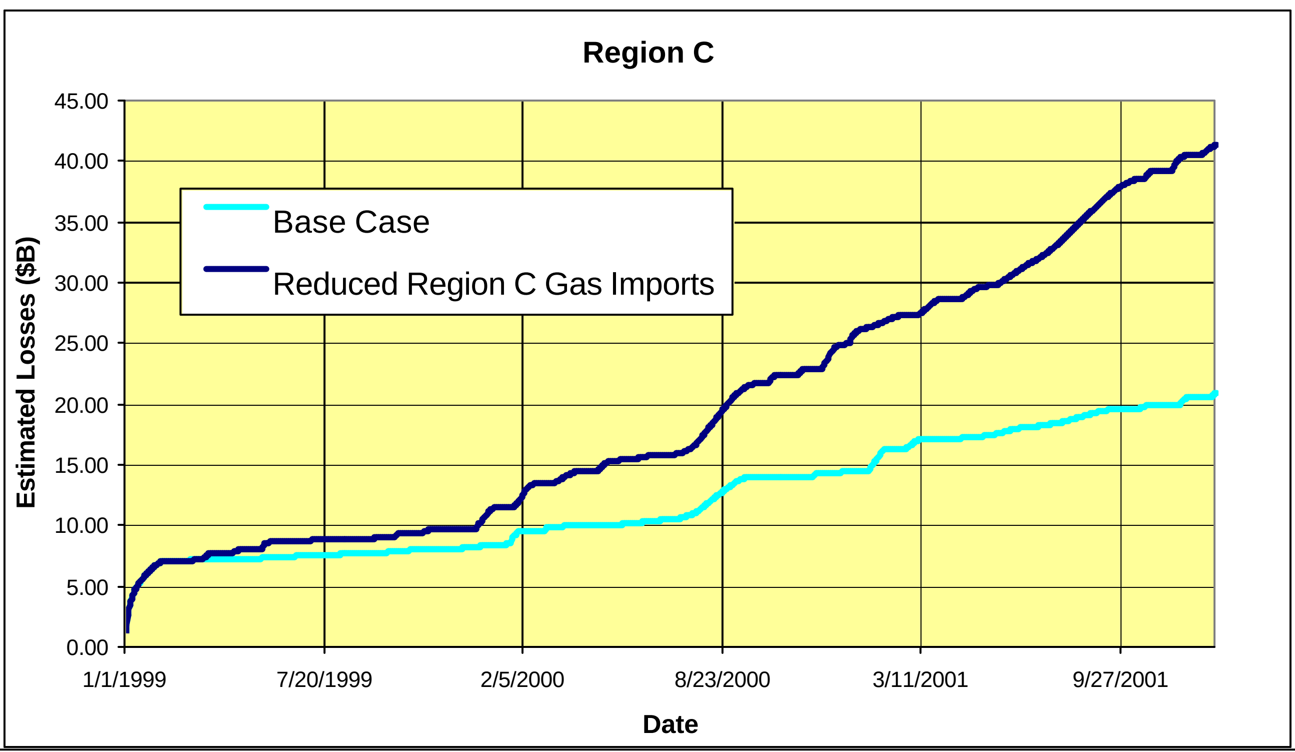

Figure 22 – Modeled Commercial Sector Losses in Cal ISO south of Path 15 – Base Case vs. Reduced Gas Import Capacity

Conclusions

Electricity shortfalls were calculated to occur in the fall of 2000, in the early months of 2001 and in the summer and fall of 2001, both north and south of Path 15. Service areas outside of Cal ISO (e.g. LADWP) did not show significant interruptions in electricity supply. This result is generally consistent with historical data and with expectations for 2001 given the demand and supply trends in the spring of 2001. Electricity shortages can occur due to either lack of generating capacity within California or due to constrictions of natural gas supply. Service areas south of Path 15 were more vulnerable to interruptions in the natural gas supply, while areas north of Path 15 were more vulnerable to loss of hydroelectric generation, as expected in unusually dry conditions. No agricultural losses were calculated: water supplies were assumed to be unlimited provided electricity was available to pump irrigation water.

The dependence on natural gas and the limitations on import of natural gas can confer short-term market power on natural gas storage facilities. Depending on the behavior of the storage operators, this condition can lead to price spikes or supply interruptions. Such episodes were observed in the model, and the calculated price peaks were well in excess of actual market prices. The desire to avoid attracting competition or regulatory constraints are factors that may moderate actual price increases. These factors are not included in the model of the storage operator's decision process. This model did, however, exhibit the countercyclical pattern of acquisition and sales seen in the historical record.

Additional natural gas storage capacity was not exploited when available. The historical record of natural gas storage utilization shows a long-term depletion trend, also suggesting that capacity is not currently a constraint on storage operations. The real behavior and the modeled behavior are increasingly similar.

The frequency and severity of power supply interruptions seen in the model depend on parameters describing behaviors of infrastructure operators. For example, the response time of markets to changes in supply conditions significantly influences the extent of supply interruptions. From a practical perspective, this underscores the importance of rapid market response in adapting to uncertain supply conditions. With respect to modeling, this suggests that developing a more accurate model of market behavior could substantially reduce the uncertainty in the current result. However, since the uncertainties in that behavior may be large it is important to understand how markets create apparent constrictions as opposed to physical system limitations.

While the patterns of commodity flows seen in the model (e.g. electric power shortfalls within Cal ISO and the annual cycles of natural gas storage) are in general agreement with actual system conditions, the commodity prices show little correspondence with actual market prices. Market prices are influenced by a number of factors not considered in the model (such as the effects of political conflicts on oil prices), and the supply curves currently used to model price setting are a very simple approximation of more complex behavior. The model results suggest that while prices based on a simple model of price-setting behavior may convey enough information to reasonably allocate commodity flows, anticipation of actual prices requires a more accurate representation of price setting behavior.

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