CALIFORNIA ENERGY COMMISSION

CALIFORNIA INTEGRATED NATURAL GAS/ELECTRIC RISK METHODOLOGY

CONSULTANT REPORT

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Prepared By:
Sierra Energy and Risk Assessment, Inc.
Robert K. Weatherwax
Roseville, California
Contract No. 700-01-001

Prepared For:
Todd Peterson,
Contract Manager

Dave Maul,
Manager
Natural Gas and Special Projects Office

Terrence O'Brien,
Deputy Director
Systems Assessment and Facilities Siting Division

Steve Larson,
Executive Director

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INTRODUCTION, PURPOSE AND RATIONALE

This document describes a series of methodologies and procedures to probabilistically assess the balance of natural gas and electric energy supply and demand within the Western Electricity Coordinating Council (WECC) generally, and California specifically, resulting from variations in temperature and hydroelectric generation conditions. The staff of the CEC may use this probabilistic analysis to determine the risk of natural gas shortage, given projected regional gas and electric load growth and assuming recurrence of historical temperature and hydro patterns. These estimates will allow Staff to estimate the risk of natural gas shortages in California and clarify policy and financial issues associated with natural gas supply.

Currently the CEC does not have the ability to systematically look at possible future gas supply and demand balances covering all sectors in California. Were gas shortages to appear, the actual shortage conditions would likely persist for, at most, durations measured in weeks. Information on a monthly basis is not produced by the CEC for most sectors even for average conditions; and no consideration is given to systematically evaluating the range of resulting balances due to the most important repeating factors affecting the gas balance: temperature and hydro conditions. Thus, probabilistic estimates cannot be produced of the likelihood of the state experiencing shortages given the levels of development of existing and projected energy delivery system infrastructure. This proposed modeling approach is intended to satisfied that perceived need for enhanced state energy policy assessment tools.

Unlike many capacity-focused electricity studies in the western region, this proposed methodology will evaluate the annual and monthly energy balance of the *combined* natural gas and electric system on a probabilistic basis.[1] It will only address extreme peak capacity needs for electric service to the degree they appear in the weather record. The methodology will explicitly address the variation in gas and electric energy demand and supply caused by

[1] This proposed methodology in that respect is similar to the studies performed in regions with limited electric energy and abundant electric capacity, such as the Pacific Northwest (PNW) or British Columbia.

historical variation in Western regional temperatures and precipitation patterns as they translate into heating and cooling requirements and hydroelectric supplies. The product of the methodology will be a probabilistic estimation of the level and frequency of natural gas shortages or near-shortages, if any, in California for selected future years.[2] This estimation will be based upon projected future gas and electric system infrastructure. Once the basic methodology is implemented and proven, it can then be used for policy evaluation by assessing the sensitivity of the results to variations in assumed levels of infrastructure development, pricing, and unplanned disruptions.

This methodology's products are intended to be immediately applicable to a range of important potential CEC responsibilities, including:

- Evaluating the need for proposed liquified natural gas terminals along the coast;
- Assessing the usefulness of the acquisition by California local gas distribution utilities of "slack" capacity on intrastate and interstate pipelines, and estimating an appropriate amount of "slack" to be acquired; and
- Evaluating the implications and fundamental prudence of eliminating fuel oil as an emergency supply curtailment backup to state natural gas supplies.

[2] The demand forecast to be produced by this methodology will be very similar in basic structure to that produced by the CEC in the evaluation of the need for the Point Conception Liquified Natural Gas Terminal in 1978.

SCOPE OF THIS REPORT

The next two sections of this report discuss the current growing interdependency between the natural gas and electric energy systems in this state. These sections trace technical and regulatory processes historically drawing the two energy forms together, and describe some of the policy obstacles arising from this demand nexus which impede the guarantee of reliable future energy supplies. Modeling considerations are introduced to simulate this growing interdependence.

The remainder of the report save the final section describes at several levels the methodology being proposed. First the recommended comprehensive and complete methodology is summarized and contrasted with current practice. The summary leads into a more detailed discussion, with accompanying process diagram, which illustrates the key steps in the proposed complete methodology. The next section describes a somewhat truncated version of this methodology, prepared in response to CEC staff comments on an earlier version of the proposed methodology. This version is meant to be more capable of immediate implementation and requires a smaller staff commitment. It is intended to establish "proof of concept" and to provide "ballpark" estimates of the risk of energy shortage to which California residents are being exposed.

The final methodology section of the report provides a comprehensive description of how the discrete outputs of the methodology are combined to develop a probabilistic assessment of the overall susceptibility of the state to a gas shortage, if any, and the expected magnitude of any such shortage.

The last section of the reports includes some feedback on the contents of a near final draft of the report by staff of the Electricity Analysis. The section also includes issues by issue responses to these comments and recommends some immediate actions steps for CEC staff to confirm data availability assumed in this methodology development.

HISTORICAL CONTEXT: How Are the Gas and Electric Systems Different Today?

The risk of curtailed or constrained natural gas supplies within the state has grown and is likely to be an important source of financial, and possibly real, risk within California in the future. In the past, electric energy supply was not threatened by a shortage of natural gas, since generators could substitute emergency petroleum stocks as provided under the CPUC priority system employed for gas supply allocation in times of curtailment. In the winter, if natural gas demand became too high, the thermally enhanced oil recovery operations (TEOR) and the utility electric generators (UEGs) would switch to oil and continue to operate. In the electric sector, combustion turbines running low on gas would switch to distillate oil, and the in-state boilers would switch to low sulphur residual oil. If the shortage were more severe, large industrial customers with backup fuel would also be curtailed and would also switch to residual or distillate oil. In extreme shortages, other industrial customers would switch to more expensive propane backup fuels. The UEGs stored up to 90 days of oil ready to be used in the event of a natural gas curtailment and could quickly switch to this backup supply.[3] Natural gas utilities required that their industrial customers maintain secondary fuel storage to qualify for non-core (*i.e.*, non-firm) customer rates. Natural gas storage and delivery capabilities were maintained at levels sufficient to meet the requirements for the high priority gas customers in a one-in-twenty year cold winter and the very rare peak cold day send-out requirements.

This well-functioning and robust system worked even during times of significant natural gas curtailments up through the mid-1980s. It grew less and less relevant as the full effects of the Natural Gas Policy Act of 1978 took hold. This new law immediately freed prices of new gas supplies and in 1985 eliminated the price caps on existing gas sources, resulting in significantly increased production. During the long-lived "Gas Bubble," natural gas supply was abundant. Gas curtailments to the California electric sector were infrequent and distributional in nature, occurring on peak days during cold waves and predominately involving the SDG&E service area. Slight distributional shortages were also experienced at times in the PG&E system as well. These shortages were addressed by falling back upon residual fuel-oil substitution by utility electric generation boilers in San Diego and by curtailment of electric generation within the PG&E control area.

[3] For example, in the case of SDG&E's South Bay plant, the residual oil was kept heated so that switch-over from natural gas to low sulphur fuel oil could be accomplished in less than two hours.

As gas became more plentiful, the use of fuel oil as a backup became more infrequent. The state's Air Boards, charged with enforcing state and federal Clean Air requirements, saw their opportunity and began prohibiting use of fuel oil even during occasional gas curtailments. Simultaneously, the CPUC put increased pressure on the utilities to reduce their amounts of oil storage so as to reduce associated carrying charges. Industrial customers also eliminated their backup oil storage capability and relinquished or forfeited their Air Board permits to burn oil.

The feasibility of fuel oil as a supply backup was further reduced by the installation of new emission-control technologies on steam boilers in California. Low-NOx burners and selective catalytic reduction equipment now being installed use flame control through spectral analysis to minimize NOx production. The difference in combustion spectra between natural gas and oil is sufficient to preclude use of the same controls (or at least the same software settings) with both oil- and gas-fired combustion. The backup-fuel option is becoming even less relevant with the construction of the new generation of gas-fired combined cycle (CC) plants. Without regulatory mandate – or, it seems, economic justification – these new plants have made no provision for backup fuel storage or consumption.[4]

The question of how reliability of gas supply can be ensured has been answered by elements of the state energy system in a very limited fashion via new and enlarged gas storage fields and the proposed liquified natural gas terminals. The newly completed gas backup facilities represent much less energy storage than was previously held on hand through oil backup. These facilities probably cannot satisfy any significant shortage of natural gas in the state or alleviate the pricing pressure that might result from significant tightening of the supply/demand balance within the state.

The increasing interdependence of natural gas and electricity systems, and the elimination of the backup-fuel option, have made California customers much more vulnerable to disruption. Today, a gas shortage would have to result in EG curtailments to protect the higher-priority gas customers. These customers cannot be curtailed in order to continue to serve the EGs because the restoration time required for electric service is dwarfed by the time required to first verify burner tip safety and then restore gas service. After the shedding of

[4] The CCs could only use (relatively more expensive) diesel or propane as backup.

a relatively few "lower priority" interruptible electricity customers, curtailment of sufficient electric generation would likely necessitate rolling electric blackouts. Thus, while EG curtailment of gas might be the "lesser of two evils," it is a very high cost option because curtailment of the electric loads could be nearly as damaging to higher-priority gas customers as curtailment of their gas supplies. As the 2002 version of the annual California Gas Report prepared by the gas utilities and submitted to the CPUC states,

> *"The implication for the future is that under* [Abnormal Peak Day] *conditions a significant portion of the EG customers could be shutdown with the impact on electric system reliability left as an uncertainty."*[5]

The 2002 CGR does not include estimates of the probabilities of occurrence of such future peak day shortages or mention the possibility of a more prolonged shortage caused by a combination of poor hydro conditions and severe weather.

The purpose of the methodology described in this report is to provide reliable probability estimates of the size and likelihood of natural gas shortages. These can be used to make regulatory and political judgments regarding future state policies to alleviate such potential problems. Any judgments thus aided could be very valuable to the overall well being of California's citizens. Such decisions could range from being as modest as helping determine the appropriate level of "slack" pipeline capacity that might be intentionally acquired by the local gas distribution utilities to as momentous as comparing the environmental impacts of the restoration of the backup fuel oil option, on the one hand, to the construction of gasification terminals and reliance upon the use of liquified natural gas supplies, on the other.

[5] *Anon.*, California Gas Report for 2002, page 27.

NEW GAS DEMAND PARADIGM AND MODELING-RELATED ISSUES

With the near-complete elimination of oil as a backup fuel for electric generation and other "lower" priority natural gas customers, planning for natural gas supplies and transmission to serve the higher-priority gas customers must now take into account overall fuel demand, including that demand associated with electric generation.[6]

Hydroelectric Supply Variability

The California energy planning problem has expanded and now needs to account for summer as well as winter gas demand. The increase in demand in both seasons is driven by the huge surge in CC generation coming on line in California and nearby areas of the West. The complication in this consideration is that EG gas demand is principally driven not just by cold temperatures (which has always been true for the higher-priority gas customers) but also by hot temperatures as well as hydro conditions in California and in the Pacific Northwest (PNW). Precipitation swings can translate into river flow differences that create a variation of more than 30,000 GWh in available California and PNW hydro generation. SERA analyses in the mid-1990s for SoCalGas estimated that, *in toto*, hydro swings could cause variations of as much as 100 billion cf/yr (~275 mmcf/d) in natural gas demand from electric generators in southern California alone.[7] Including northern California EG gas demand and its loss of instate hydroelectric generation makes this potential wet-dry swing much more pronounced even excluding the likelihood of coincident hot weather.

When studied more closely by SERA staff, the variation in available hydro generation was found to be attributable about 2/3 to the available secondary hydro generation from the PNW and BC Hydro (BCH) and 1/3 to the variation in total California hydro (with the majority generated by PG&E). The amount of hydro available is essentially unpredictable from one year to another because the PNW hydro storage is only equivalent to about six months of Mainstem Columbia River flows. (California hydro has even fewer months of storage.) In addition, annual California hydro generation is considered by California Department of Water Resources (CDWR) staff -- a view supported by analysis of the historical hydro

[6] Higher priority gas customers generally consisted of the gas "core " customers while the lower priority customers generally consisted of the "noncore" customers though the priority ranking was actually focused on the feasibility and cost of backup fuel and not the source of the gas purchases.

[7] Weatherwax, R. K., et al, SERA, *Cogeneration/UEG Competitive Pricing Study, California/WSCC UEG Data Book,* SoCalGas Gas Marketing, June 30, 1993.

generation data -- to be wet and dry each about 40% of the years and near average only about once in every five years.

There are two other confounding factors that need to be to considered to accurately estimate the frequency of adverse hydro. First, hydro conditions in both regions tend to vary in tandem with a correlation coefficient of about 0.2, and year-to-year correlations in hydro generation in each region are even more highly correlated. (When it is dry in one region, it is somewhat more likely to be also dry in the other region. Furthermore, when it is dry in a given year in either area, it is more likely that the next year will also be dry in that same region.) The positive correlation between the hydro conditions in the two areas in any one season is attributable to the fact that the entire U.S. West Coast tends to see similar weather patterns, due to similar offshore water temperatures and other factors. Some of the year-to-year correlations may be attributable to known weather effects like the El Niño and La Niña events, whose effects on offshore water temperatures have cycles lasting longer than a year.

More disturbing, from a California energy policy perspective, are the recent atmospheric physics studies that point to the existence of a Pacific Decadal Oscillation (PDO). In simple terms, this PDO is a tendency of weather on the Pacific coast to have a bi-modal distribution with an overall period of 40 to 50 years. This suggests that California weather typically fits two quasi-stable patterns, and tends to follow one of them for a period of 20 to 30 years at a time before oscillating into the other for another 20 to 30 years. Some of the findings indicate that the last two decades have followed one PDO pattern which may now be swinging back into a another weather pattern of the type observed during the decades prior to about 1980. The last two decades have seen above-normal precipitation along the Pacific coast with higher than normal hydro generation, while the prior two decades saw below-normal precipitation levels and correspondingly lower average hydro generation opportunities. On the other hand, proponents of the onset of global warming due to accumulation of greenhouse gases in the atmosphere point to climate models suggesting that the Pacific coast might see increased precipitation as a byproduct of the projected warming of the earth. From a policy perspective it is better to anticipate, at least, no better hydro conditions than observed in the recent past (and for which good data are available) so that we will be less likely to understate the degree of risk potential for the state.

Temperature-Driven Demand

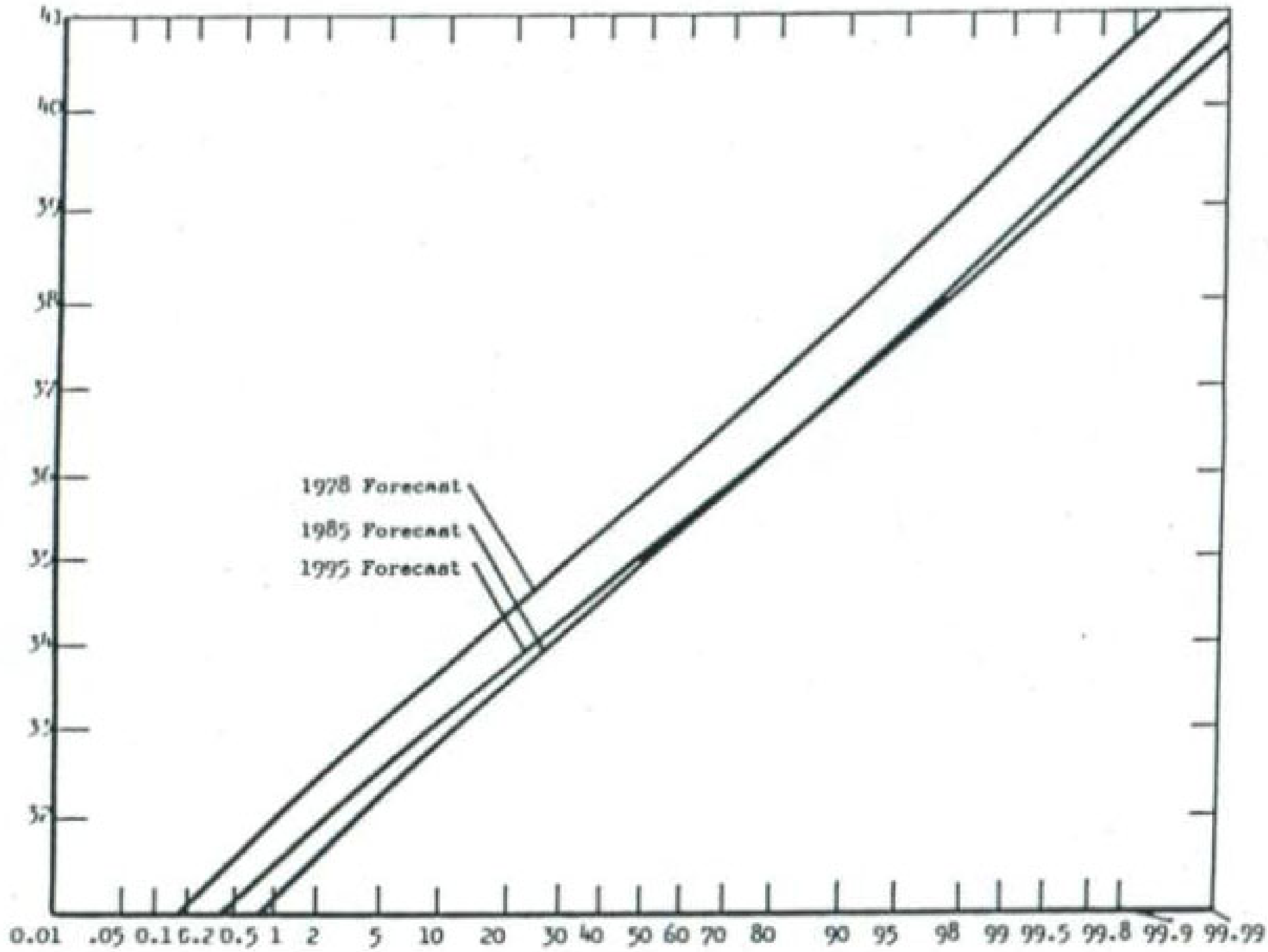
Since we currently plan for full satisfaction of all higher-priority gas demand, and since gas supplies are integrated throughout the region, it is necessary to consider the entire regional gas demand, which includes segments heavily influenced by temperature variations in both the winter and summer. The total amount of energy devoted to serving wintertime space and water heating load (primarily gas) in California is much greater than the total amount of energy needed to serve summer air conditioning loads (primarily gas-fired EG). In addition, during hot summers, there is actually some reduction in gas demand due to reduced water and swimming pool heating energy requirements, offsetting somewhat the increase in gas demand to serve the EGs. In contrast, the reduction in refrigeration and other related end-use load during a cold winter is negative feedback of a much lesser magnitude. Thus, looking at an energy balance in the state requires paying closer attention to the winter temperature effects in the region.

Key winter temperature driven variations in demand are found in residential and small commercial space and water heating demand within California and the PNW. As can be seen in Figure 1, the increase in overall California burner-tip natural gas demand by high priority customers attributable to winter temperatures was estimated by the CEC Demand Analysis Office to be greater than 300 mmcf/d in 1995 in 98 out of 100 winters (*i.e.,* the difference between about 3,800 mmcf/d demand during the two-percent worst winter versus the 3,500 mmcf/d demand projected for a median winter).[8] When that estimate was produced in 1978, the EG demand for gas was ignored, although the estimated impacts of the building and appliance standards were included (and indeed contribute to the differences in demand between the three forecasted years plotted on the figure). Currently, no entity to the best of our knowledge projects future year increases in statewide gas demand attributable to the concomitant severe winter increases in electric space and water heating load. Thus, we do not know how much the 300 mmcf/d variation might have changed or will be changing. Also unknown is whether or not there are positively correlated above-normal summer temperature occurrences in the same year, which may trigger further increased electric loads

[8] Weatherwax, R. K., M. R. Jaske & A. N. Doi, A Forecast of Utility Energy Demand and Peak Load for California: 1978-2000 in *California Energy Demand: A Collection of Selected Methodology Papers*, Pergamon Press, 1979.

Figure 1

CALIFORNIA STATE P1-P4 REQUIREMENTS FORECAST (100 MMCF/d)



PROBABILITY OF GAS REGUIREMENTS OCCURRING (%)

and demand for gas to satisfy those loads.[9]

Weather-driven variations in PNW demand must be considered because of their overall effect on the gas and electric balance in California. Increases in indigenous demand in the PNW can significantly reduce the amount of electric and gas energy available to help serve California loads.[10] It seems likely that the total variation in winter gas demand in the PNW might be of the same magnitude as that seen in California; as the somewhat more lax building and appliance standards and potential for larger temperature excursions there are partially offset by a lower population in the region. It is also feared that the positive correlation in winter temperatures between the two regions may be quite high, especially in times of adverse weather. At the end of 1990 and in February 1992, both the PNW and California experienced very large temperature excursions caused by massive outbreaks of arctic air. This so-called “Siberian Express” caused gas curtailments and skyrocketing wholesale electric rates.

Pending further checks, we would recommend excluding the non-EG winter weather variation in demand in the inland southwest (ISW) due to the limited population found there, the expected slight correlation in temperature between regions, and the very limited amount of electric space heating. However, if a larger area that encompasses gas-producing areas such as Texas’ Anadarko region is considered, the impact of cold weather on gas production from the ISW and the remainder of the Western Region may necessitate a closer look at low-temperature correlations. For example, the cold waves of the early 1990s caused gas supply reductions due to frozen gas wells and other weather-related effects.

In the summer an entirely different set of demand drivers need to be considered. Naturally, electric air conditioning is the key summertime driver of elevated load in our region, followed by residential and commercial refrigeration. Storing gas for the next winter and meeting the summer peak and overall elevated electric load levels are the principal remaining demands for summertime gas. Since there is relatively little air conditioning in the PNW on a population-weighted basis, it seems reasonable to ignore weather-induced variations in summertime demand in that region. On the other hand, while collecting weather data for the

[9] One important product of the use of the proposed methodology would be the estimation of the correlation between cold winters and warm summers in California.

[10] Twenty years ago, space heating in the PNW was satisfied about equally by gas, oil and electricity. Significant water and space heating conversion from oil have since occurred, further exacerbating this issue.

winter impacts it may be relatively easy and cost-effective to extend the PNW gas demand analysis to the summer as well.

The impact of the variation in summer weather is less clear in the ISW, where ubiquitous use of air conditioning consumes substantial amounts of energy. The average load may be so high on a population-weighted basis that weather-induced variations in electric demand can be ignored, since the demand is essentially saturated. We recommend assuming that the ISW load is constant, particularly during the initial application of this methodology.

Capturing the Variation in Weather to Estimate Risk

Figure 1 presents distributions of possible levels of high priority demand due to historical variations in temperature for three years: 1978, 1985, and 1995. The figure is plotted on probability paper, with a vertical line (ordinate) representing the average annual daily demand in MMCF per day and a horizontal line (abscissa) representing the probability of actual demand being less than or equal to the amount determined by the intersection of any one of the three annual curves and a perpendicular line drawn above the abscissa. Thus, for the three forecasted years, the 50-50 point is projected to drop from about 3600 mmcf/d to about 3500 mmcf/d, mostly due to enhanced building and appliance standards and retrofit insulation programs.

If 3700 mmcf/d of reliable supply were available in each of these years, the likelihood of meeting high-priority demand would grow from about 3 of 4 years (75%) in 1978 to about 5 of 6 years (85%) by 1995. Similarly, the methodology being proposed in this report is intended to forecast for the policy analyst the likelihood of tight or exhausted gas supplies for any of the next ten years, given exogenously assumed levels of supply infrastructure development and variations in weather consistent with those observed in the last quarter century.

Unlike the pioneering 1978 study, however, which dealt only with variation in demand for the high-priority gas customers due to variation in California winter temperatures, SERA now proposes a much broader study befitting the new energy conditions facing the state. Using the proposed methodology, the study would examine the regional variation in total gas demand (including gas used for electric generation) with both winter and summer temperatures, including impacts of correlated hydroelectric conditions within the region.

These results would be derived from exogenously estimated levels of energy system infrastructure, fuel prices and economic activity, all of which could be varied to study their respective impacts.

The heart of the issue in developing this risk methodology is the accurate estimation of the mutual dependancies between the various temperature and hydro factors as they vary across the region and jointly affect demand of both electricity and gas. This problem of accurately estimating energy service-related risk makes the undertaking too complicated to use the relatively straightforward mathematical method which generated the results presented in Figure 1. (Those results dealt with only one variable: winter temperature, with the assumption that heat load is linearly proportional to heating degree days or HDDs.) Alternately, combining the most unfavorable assumptions (worst case hydro conditions in all regions, cold winters, warm summers) would likely generate results that were very disturbing, but essentially unrealistic; such results would have no practical policy value. As already mentioned, we recommend solving this critically important forecasting problem through use of coincident, consecutive historical weather data (including water years for hydro generation estimates), which we call *weather vintages*, and forecasting each year's weather vintage impact in selected future years with postulated levels of infrastructure.

The weather vintages approach has been employed in numerous energy applications, although it is usually limited to consideration of hydroelectric conditions. Using weather vintages would provide immediate benefits, including assured accuracy in capturing the covariance of weather between regions and a "simplicity" of basic approach. Data collection is a potential concern, but the needed data are available for collection; the only issue would be the level of effort required. Employing a relatively data-intensive approach would reduce the importance of any particular data stream and would permit random errors to tend to cancel out. This conforms to the demand forecasting philosophy the CEC has maintained for decades.

We propose to employ weather and hydroelectric data beginning in 1975, for several reasons. First, as discussed later in this report, PG&E's hydro data becomes much less refined and reliable prior to that point.[11] Secondly, weather patterns may be changing with the potential

[11] In contrast, the PNW and BC Hydro regions employ 50 years of river data and have reliable data going as far back as the 1920s. Both regions have important contractual incentives for keeping a more precise historical database than that maintained in California.

of global warming, so use of earlier years of data may induce some climatic inaccuracies. Finally, using about 25 years of data will permit Staff to claim – with over a 70 percent level of confidence – that they will have considered a one-in 20 year level of demand.[12] This appears to be an excellent compromise between analytical precision and level of effort required.

[12] Assuming independent trials; level of confidence = 1 - (.95)^25.

SOME RELEVANT CURRENT MODELING PRACTICES OF CEC STAFF

This section contains a brief comparison of current CEC modeling practice with several key risk-modeling considerations we will be proposing. The CEC currently produces complete, independent demand and supply forecasts for demand and supply of electricity and natural gas for California. In the process of producing these forecasts, CEC staff also prepare independent forecasts for selected non-California energy elements. The Demand Analysis Office produces forecasts for most sectors and end-uses in California using an array of demand forecasting tools, mostly produced in-house. The Electricity Analysis Office produces forecasts of EG demand by fuel type and EG output by running PROSYM, a vendor supplied code, and then aggregating hourly forecasted operations into monthly results for all individual generation stations, including all the larger cogenerators found in the entire synchronized WECC.[13] The North American Regional Gas (NARG) model, another vendor supplied product, is used by the Natural Gas Office to project selected future year gas supply for numerous gas supply nodes throughout the interconnected North American region to achieve gas supply and demand equilibrium at each exogenously specified gas demand node. The new Monthly NARG model now under development will permit monthly projections of gas supply and demand equilibrium at each node in North America for the nearer-term future.

Current End-Use/Sector Forecasting

The electric demand forecast for each California load zone comes from economic sector-specific forecasts produced by the Demand Analysis Office's demand forecasting models. These models forecast demand for weather-sensitive end uses by weather zones within each utility, and demand for other end uses and non-weather-sensitive sector loads (*e.g.*, street lighting) across each full utility. Electric energy demand is forecast each month and used to develop peak load forecasts. These results, which are based on average weather conditions, are then turned into hourly loads for each of the California demand zones in the PROSYM model. These zones consist of Edison, LADWP, San Diego Gas and Electric Company (SDG&E), Imperial Irrigation District and Northern California, split into PG&E and Public Power load north of transmission Path 15 between the Los Banos and Vincent substations and PG&E load south of Path 15.

[13] PROSYM is one of the chronologic production cost models employed by the CEC in simulating the Western Region.

Loads outside of California used in PROSYM normally employ historical average weather year loads for each region or state to which an assumed growth rate is applied.[14] As currently employed by CEC Staff, PROSYM assumes unlimited supplies of natural gas throughout the Western region to fuel individual power stations. Resulting projections of annual EG natural gas demand in each of the four NARG model demand regions in California (PG&E, SoCalGas, SDG&E, and the TEOR region of Kern County) as well as the several other WECC nodes are aggregated and placed into a database of PROSYM modeling outputs.

The Demand Analysis Office also produces average-weather based forecasts of annual natural gas demand by weather zone and utility. Many end-uses/sectors are forecast simultaneously with electric demand, although a few, such as small cogeneration demand, can only be forecast separately. Both the EG sector gas demand forecast for the entire Western Region and the non-EG forecasts by California utility area have to be produced each month in order to support the NARG Monthly model under development. NARG demand projections for the rest of the United States come from available published data and reflect typical weather conditions.

In the CEC's PROSYM inputs, all available WECC hydro generation is normally assumed to reflect long-term average hydro conditions in every hydro basin in every region. However, PROSYM does have the ability to use off-nominal hydro conditions, and data sets are available for dry and wet years in California and dry years (at least) in the PNW and elsewhere. In fact, Henwood has a dry hydro data set that reduces hydro generation in each area of the region by an equal 30%. This is represented by Henwood staff as being equivalent to a one in 33 year drought condition region-wide.[15] (Of course, it is well understood that all WECC regions would not concomitantly have identical 30% reductions in hydro generation; some areas would be drier and some areas wetter, resulting in a net generation reduction of 30% throughout the region.)

The NARG model takes inputs from the outputs for the demand models and PROSYM and combines them with data acquired from other sources. The demand models and a separate thermally enhanced oil recovery computation provide NARG model inputs for future annual

[14] Henwood, PROSYM's vendor, has recommended assuming annual load growth of 2.1% for the out-of-state load centers in Economic Analysis of Valley Rainbow Interconnection, October 5, 2001. Filed as part of testimony in CPUC proceeding A.01-03-036.

[15] *Ibid*, page A-5.

non-EG natural gas demand for each of the California utilities and San Joaquin Valley oil production. PROSYM outputs are aggregated to provide the use of gas by EG for each utility in California.

Key Socioeconomic and Fuel Price Inputs and Feedback

Extremely important to the overall forecasting process are other data flows associated with demographics, energy prices and economic activity scenarios, which are crucial to coordinating all the individual modeling procedures. Forecasts of population and retail electricity and gas prices are needed as inputs to the demand models. Economic activity (particularly income) also strongly influences the magnitude of demand and thereby affects energy prices.[16] Most fuel price forecasts are produced endogenously and lag one cycle as discussed in the next paragraph. Demographic data comes mostly from the Department of Finance, so it is consistent with other state projections. Most economic projections come from special CEC contracts with consultants to forecast economic activities for special state sub-elements as required.

Since the 1970s the CEC has employed a novel lagging approach to capture the feedback relationship between gas and electric prices and supply and demand in the performance of a complete California energy system assessment. In assessment cycle "N", the demand forecasts rely upon the fuel prices that were calculated in special CEC fuel price forecasting models whose inputs are the outputs produced by the CEC demand and supply models during the previous cycle, "N-1". The N-1 cycle outputs employed as inputs to the Nth cycle include the cost of electric generation as computed by the PROSYM model and the cost of natural gas as calculated as a result of the equilibration of gas demand and supply in the NARG modeling. Naturally, fuel prices computed during the N cycle would be employed as inputs for the "N+1" cycle.[17]

[16] Some feedback also exists between energy prices and economic activity, but it is of second-order importance and has little effect on the overall analysis.

[17] This approach may seem, at first blush, awkward and inelegant compared to using a massive general equilibrium model to simultaneously compute energy prices, supplies and demand. Certainly with the improvements in computer power and the huge decline in the cost of computing such an equilibrium model may now in theory be possible. However, we know of no extant model which simultaneously offers the necessary level of comprehensiveness and detail, and we are very skeptical as to the realistic likelihood of producing such a model.

These state-of-the-art CEC-employed modeling tools represent a rich and fertile base of knowledge and methodology generated over more than two decades of effort. Such a knowledge base is nearly priceless and clearly unsurpassed in the world. It represents an ideal foundation from which to evolve – largely through increased coordination – a risk methodology to capture the new gas/electric paradigm.

SUMMARY DISCUSSION OF KEY ELEMENTS OF PROPOSED MODELING

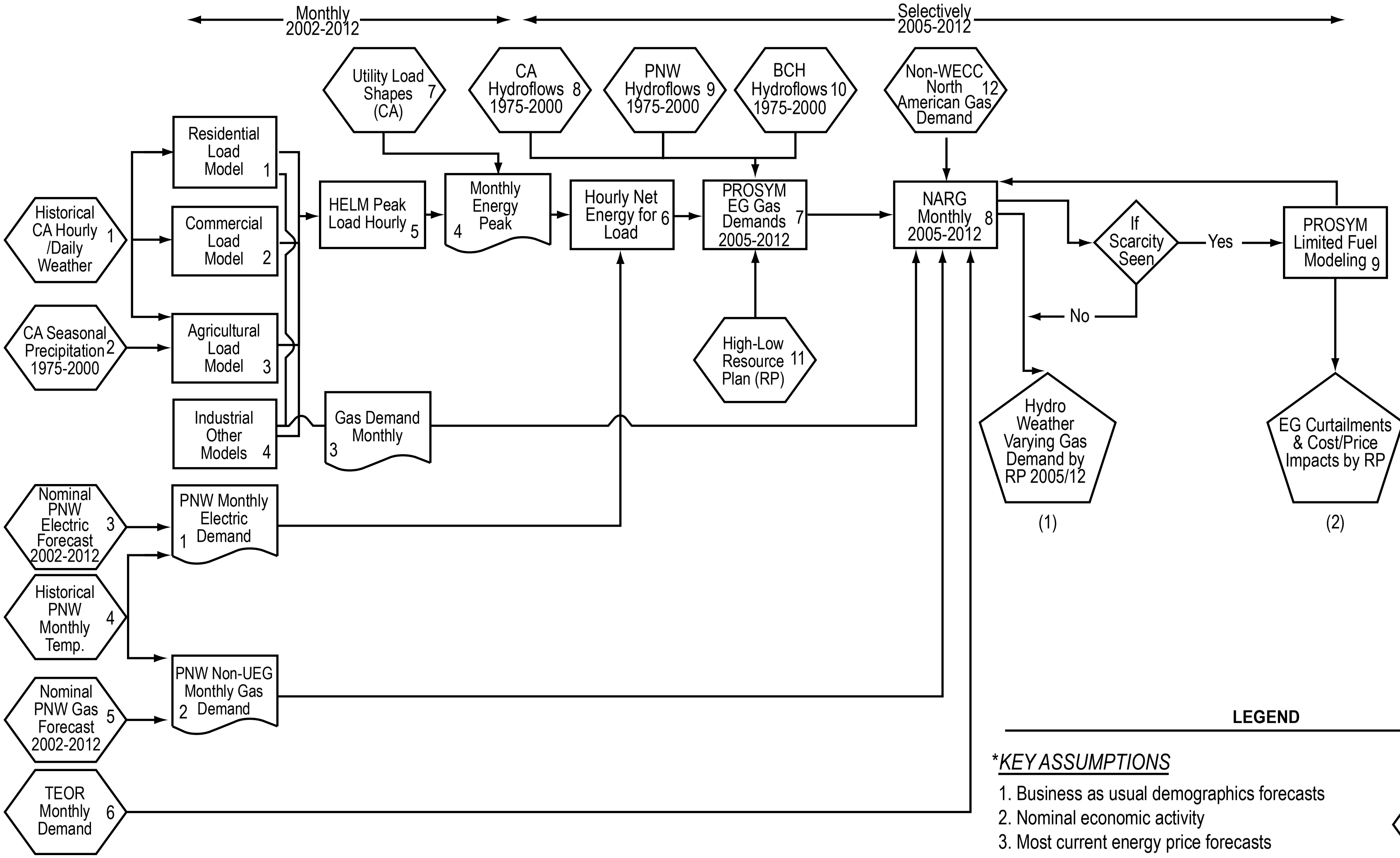
The proposed integrated modeling method discussed in this section reflects a comprehensive and detailed approach for fully capturing the interdependent supply and demand for natural gas and electricity in California and for measuring the risk of experiencing scarcity of natural gas supply due to variations in weather. See the accompanying task flow diagram (Figure 2) for a detailed process flow of the input data, modeling tasks and products associated with this proposed methodology. The process would proceed generally from left to right, albeit with many tasks suitable for concomitant development. The diagram distinguishes between data inputs and outputs, formal- and spreadsheet-level models, and final outputs. The categories of current "Demand Analysis Office-type" tasks are exclusively displayed on the left of the model. Current "Electricity Analysis Office-type" tasks are listed in the middle of the diagram. Towards the right hand side are displayed the current "Natural Gas Office-type" tasks.

The next major section of this report, "Task-Specific Description of Proposed Methodology," will address each of the activity boxes presented on Figure 2. The following section, "Methodological Shortcuts for Producing Preliminary Results", describes some task eliminations/truncations that could help more rapidly produce initial results that would both be useful by themselves and helpful in determining the optimal final form of the overall methodology. In the remainder of this section we will discuss the key concepts and elements of the proposed approach, drawing from the preceding discussion of the current state of CEC forecasting. This discussion of each general type of recommended activity will distinguish generally among the several CEC functions and responsibilities.

Using Historical Weather and Synthetic Hydro Data

As previously noted, the main method by which this approach captures the risk and uncertainty inherent in the California energy system is the simulation of the regional gas and electric demand in selected future years using the actual weather and concomitant unconstrained water flow ("hydro") conditions for each of the entire 26-year period from 1975 to 2000 (the "weather vintages"). Using the entire 26-year weather/hydro history to simulate each future year will create a distribution of vintage forecasts from which risk and uncertainty estimates can be readily drawn. By dealing with a large chronological set of observed data, we can insure that the complex covariances among the numerous significant

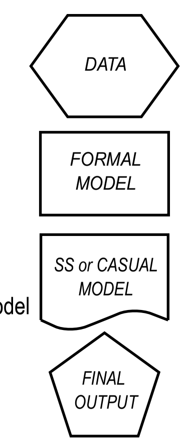
FIGURE 2: PROCESS FLOW FOR NATURAL GAS/ELECTRICICTY RISK METHODOLOGY*



LEGEND

KEY ASSUMPTIONS

1. Business as usual demographics forecasts
2. Nominal economic activity
3. Most current energy price forecasts



ACRONYMS/ABBREVIATIONS

BCH	British Columbia Hydro
CA	California
EG	Electricity Generation
HELM	Hourly Electric Load Model
NARG	North American Regional Gas Model
NON-UEG	Non-Utility Electricity Generation
NON-WECC	Non-Western Electricity Coordinating Council
PNW	Pacific Northwest
RP	Resource Plan
TEOR	Thermaly Enhanced Oil Recovery

contributors to joint electric and gas demand are captured as accurately as possible in a manner comprehensible to the layperson. The 26-year period starting in 1975 is suggested by the absence of refined PG&E hydro data for earlier years and the consideration that 26 years should be adequate to give results at a sufficiently high confidence level for public policy work. The level of accuracy should increase in future years as iterations of this analysis can be updated to incorporate the results of years just passed. The actual temperature data for the 26-year period would be used in the forecast of the non-EG demand for gas and electricity in California and the PNW. Actual hydro conditions resulting from weather impacts in California, the PNW, and BC Hydro for the same 26-year period would be employed in the electric generation forecast.

It is important to understand that using 26 years of historical hydro data does not mean that we will employ the actual hydro generation results for the past 26 years. What we propose to use are the predicted unconstrained river flows that *would have been observed* in each of the 26 years if the California, PNW and BCH hydro systems were configured as we project they will be in each future year being simulated. The changes in hydroelectric generation (from those actually observed in the past) that would be reflected in these future year vintage simulations would include among other changes new hydroelectric generation. In California, for example, PG&E's Newcastle power plant and the much larger New Melones project controlled by the Western Area Power Administration were added during the mid-1980s, increasing the amount of potential generation from earlier hydro vintages. Similarly, settlements arising out of FERC relicensing proceedings for selected California hydroelectric projects have altered flow diversion for other water users and significantly increased minimum flow requirements on selected rivers; this would also change the shaping of available hydro generation. Similar changes have occurred in the PNW and BCH, including particularly important flow modifications in the Mainstem Columbia River system to facilitate conveyance of smolt to the Pacific Ocean. Use would be made of standard "synthetic" data manipulation techniques to capture the weather-caused variations in potential hydro generation that would result if each year of the historical weather-generated river flows were repeated identically in each of the future years of study. Hydro data availability is crucial to this approach, but we believe that acquiring the necessary hydro data for use at the CEC is eminently practical, since it already has been accumulated by various groups in each of the three regions.

The other key data element is the actual daily average or high and low temperature (and possibly humidity) data for locations throughout California and the PNW. The CEC has always had substantial amounts of locationally-specific weather data on hand extending back many more than 26 years, and CEC staff seem confident they can get whatever supplemental weather data are required.

This recommended approach of using 26 weather vintages is an enlargement of normal CEC procedures, but not a fundamental alteration in how each of these genres of modeling are currently done. At present, the CEC Demand Analysis Office explicitly relies upon typical temperature-humidity-cloud cover data for each region of the state when producing its annual gas and electric demand forecasts. The Electricity Analysis Office's simulation of WECC operations does not explicitly take into account temperature and hydro conditions, but it employs load data and hydro data obtained by averaging 30 or more years (in many cases) of collected historical data. These historical data reflect the averaged impacts of key weather factors, including hydro conditions. A similar situation exists in the gas supply modeling performed by the Commission staff, in which NARG's demand nodes reflect average weather conditions and (to the degree it is significant) average hydroelectric conditions in the remainder of the country.[18] We propose to extend the vintage "dimensions" for each of these modeling venues, so that the results from each major model will be a set of distinct forecasts for each weather vintage – from which risk assessment estimates can be computed.

The PROSYM inputs for each weather vintage for each hydroelectric station consist of the amounts of hydro generation in GWh along with maximum and minimum permitted levels of capacity in MW.[19] These inputs can change as frequently as weekly. These inputs for the 26-year set of PNW historical vintages are available from sources within that region, including the Pacific Northwest Utility Coordinating Council (PNUCC) and BPA. Inputs for PG&E hydro can be obtained (for example) from the UPLAN modeling, including UPLAN's hydro modeling module.[20] Data for the other significant California hydro stations – including SMUD's Upper American River hydro, the Don Pedro and Hetch Hetchy hydro

[18] Fortunately, the Gas Supply modeling is simplified by the fact that there is relatively little hydroelectric generation of any kind outside of the Western Region – and where there is hydro, there is very little gas-fired generation.

[19] The inputs described assume that the CEC does not purchase or otherwise acquire the detailed hydro modeling module of the overall PROSYM modeling system; that would then necessitate use of a more fundamental set of vintage-specific water flow data.

[20] UPLAN, another chronologic production costing model partially sponsored by the CEC, has been employed by the CEC in selected policy work and was relied upon by the state for modeling the potential economic impacts of the proposed PG&E hydro divestiture.

projects, and Western's Northern California system – could be estimated from the variation in vintage-specific generation encompassing all of PG&E's hydro system.

The final source of significant annual hydro variation is the BC Hydro system. BC Hydro produces the necessary operating assessment from which the data can be obtained. This information is available on both sides of the border and is probably readily accessible to Commission staff, based on SERA's experience developing the Surplus Energy Resource Assessment Model (SERAM II™), which uses such data.[21]

The only other source of significant hydroelectric generation in the WECC is the Colorado River system, which has enough storage (four year of average river flows) to effectively decouple its operation from short-term weather cycles. Since use of average monthly generation should therefore be consistent with the precision we need, the full 26-year set of data for the entire WECC is not needed, at least for the initial assessment.

Proposed Utilization of CEC Models to Forecast California Gas & Electric Demand

The CEC's sector-specific energy demand models would be employed to generate the forecasts for California by utility/weather zone for both gas and electricity. We assume that the historical monthly weather data for each California weather zone are readily available. Monthly forecasts of gas demand for higher priority users would be produced based upon the monthly HDDs associated with each of the historical weather years applied to the space heating and water heating demand. Other end uses would have predominately, if not totally, temperature-insensitive monthly loads, and would thus be the same for all vintages. The gas demand forecasts would be aggregated from the utility/weather zone and reported at the level of each of the three California utility demand nodes in the NARG model.[22] Baseline economics and demographics would be employed. Sensitivity cases and/or scenarios could be dealt with later to the degree needed. If the forecast were produced for each of a 9 year interval between 2002 and 2010 then a total of 9*26 = 234 yearly forecasts would be

[21] SERAM II is a load duration curve production costing model used to model the non-California portion of the Western Interconnected Region in conjunction with the SERASYM chronologic production costing model. SERAM II employs fifty years of water vintage data, extending from about 1938 until 1988, for each region (PNW and British Columbia).

[22] As discussed *infra,* these are the PG&E service area and the two SEMPRA utility service areas (SoCalGas and SDG&E).

produced.[23] Some restoration of atrophied CEC demand-modeling capability would be needed to estimate the monthly gas demand through use of the end-use forecasting models. Such capability might also be needed to capture the variation in demand due to vintage-specific variations in number of heating-degree days in sectors where space heating represents an important gas demand. In and among all modeling segments, additional data manipulation, transfer and storage software must also be created.

The electricity energy models would need to produce monthly electricity forecasts for each of the same 26 historical weather vintages done for the gas forecast. I recommend using the "business as usual" forecast of demographics, fuel prices and socioeconomic factors for the initial study, since it will be a conservative estimate – it will forecast higher energy demand than other possible scenarios. Summer air conditioning load variation with wet and dry bulb temperatures and/or cooling degree days (CDDs) must also be captured. We presume, subject to clarification, that variation in heating load as reflected in HDDs will also need to be factored into the analysis for the commercial and residential building sectors. One other issue should be considered: the need for a "dry year adder" in the agriculture sector for summer water pumping, which in the late 1970s was thought to add over 100 MW to the summer load. This would coincide with a dearth of hydroelectric generation and could represent an important amount of energy.[24]

The output of the electricity sector models would be integrated in the Hourly Electric Load Model (HELM) at the California electric utility service area level to produce annual forecasts.[25] A spreadsheet model is then used to forecast monthly energy and peak loads. Per Tom Gorin, I understand that a Demand Analysis Office spreadsheet model then converts the forecasted monthly net energy for load and peak into either a chronologic or load duration curve projection for all the hourly loads in each month. This California forecast product would then be handed off to the Electricity Analysis Office staff as a key input for

[23] The annual forecasting is proposed a) because it is thought to be as easy as doing forecasts for only selected years, and b) for possible annual use if the risk methodology is later run annually.

[24] This estimated impact reflects our best recollection of PG&E's claim during the 1976-77 drought.

[25] HELM is an EPRI-developed model employed by the CEC for peak load forecasting.

PROSYM modeling of electric system operations.[26]

PNW and Other Out-of-State Demand Forecasts

The CEC does not currently formally forecast electric or non-EG gas demand beyond the California border. Weather-averaged projections of future annual total electric send-out and peak load are obtained from others in the Western electric region and converted with ancillary PROSYM modules into hourly loads for each PROSYM demand node in the WECC. These hourly loads are usually limited to one typical week per month in order to reduce PROSYM simulation time, although a full 52-discrete-week annual simulation is entirely within the model's capability.

A similar data source situation exists with respect to the gas demand inputs to the Monthly NARG model under development by CEC staff. Out-of-state gas demand data mostly come from public sources but are less extensive than the hourly electric data required. The demand data required would be limited to total monthly demand from non-EG users. EG demand naturally arises from use and output of the PROSYM model which can then be used as input in the NARG model. A full North America data set is required to run the gas model, so total monthly demand forecasts for the remainder of the nation must be obtained from various sources.

More detailed inputs would be needed for PNW energy demand forecasts at the NARG nodes for gas and at the PNW regional level for PROSYM to reflect weather sensitivity.[27] Monthly PNW electric demand data as affected by weather may be available from contractor studies recently performed for the CEC. If not, this information may be available from the Pacific Northwest Power Planning Council or used as inputs to the annual determination of Firm Load Carrying Capacity in the region by the PNUCC. The presence of several other important information sources in the region (including BPA) makes acquiring future monthly electric demand data very likely. These monthly average weather based forecasts of electric demand for future years would then need to be statistically adjusted for each weather vintage

[26] Alternately, the LOADFARM module of the PROSYM module could be employed to accept monthly peak and/or energy forecasts and produce future hourly load forecasts for each PROSYM load node.

[27] The PNW region consists of Washington, Oregon, most of Idaho and western Montana.

to estimate changes in heating and cooling loads resulting from actual weather. The results would be then reformatted as PROSYM input.

Collection of the necessary gas demand forecast data for the PNW region may be a bit more troublesome; such data are unlikely to be integrated throughout the PNW region to the same degree as electric demand data. These data would be used as inputs to the NARG modeling and will need to be assembled at the PNW NARG demand node level, which consists of each of the states in the PNW. Efforts to collect these data should make certain to capture the currently ongoing regional switch-over from fuel oil to either electricity or gas space and water heating. As with the hydro data, the preferred approach would be to apply the weather vintages to the future average weather demand forecasts, thereby capturing the changeover in fuel-type saturations for water and space heating. These data could be generated by using a statistical approach and historical data for the recent past to capture weather effects, and/or by using an end-use level forecast for future years based on average weather during each month that would be adjusted to reflect the actual monthly weather vintages. The statistical approach would require gathering historical demand data at an aggregated level that would need to be statistically analyzed by CEC staff. The alternate, end-use approach would necessitate either obtaining the necessary forecast from some other entity or generating in-house end-use level future forecasts.

Monthly gas and electric demand forecasts for the rest of the WECC would come from current sources and would reflect average weather conditions. In PROSYM, most of the demand nodes for the rest of the WECC would be at the state level but they would also include the Canadian provinces of Alberta and British Columbia and Baja California del Norte. A similar situation exists for the NARG model, though it is a bit more aggregated in its demand modes.

Proposed Production Cost Model Utilization (First Application)

The initial PROSYM runs would be used to determine the unconstrained electric generator (EG) demand for natural gas by weather-vintage-month by forecast year by NARG demand zone throughout the WECC. PROSYM would either build one input set of the chronologic hourly loads for each weather-year for each of its California and PNW zones from the monthly energy and peak demand forecasts, and/or receive that finalized information from a specially developed HELM-output processing model.

A possible separate modeling issue in the PROSYM data sets is the fuel used in the QF facilities. Naturally all of the units that use gas will need to reflect that use and have accurate heat rates associated with electricity generation from that gas consumption.

Another important issue will be to select a resource plan. I suggest using the highest and lowest new generation cases that have been reported upon in the most recent CEC forecast. As discussed earlier, the hydroelectric generation in the PNW and BCH needs to be synchronized with the hydro in California and with the weather year vintages to produce at least 25 years of data starting with the hydro conditions in July or August of 1975 and continuing until June or July of the CY 2000. The data from all of these annual year load / hydro data sets will need to be run through the PROSYM model for each year of simulation for each of the high and low resource scenarios. It is suggested that the initial runs be limited to forecasts for the years 2005 and 2010, since the run-times per year considered will be substantial and because they will be used in the NARG monthly model working at multi-year intervals. The disaggregated output from PROSYM would be monthly gas demand by WECC-NARG demand zone for each of 25 weather cases for each forecast year for each of the two generation scenarios.[28]

Proposed NARG Monthly Model Utilization

The proposed methodology requires the incorporation of a forecast of monthly gas demand of the thermally enhanced oil recovery and other gas fired cogeneration units (TEOR/Other Cogen) not reflected in the PROSYM modeling. The Monthly NARG model currently under development by the Natural Gas Office would be then used to integrate the PROSYM projected monthly electric-generator gas demand for the "unconstrained natural gas supply case" with the higher-priority gas demand forecasts and the TEOR/Other Cogeneration forecast. California/PNW higher-priority gas forecasts would be vintage specific as would the PROSYM outputs which would vary with generation scenario as well. Remaining higher-priority gas demand and TEOR/Other Cogeneration demand would be assumed to be the same for all weather vintages for both generation scenarios.

[28] The ten NARG demand nodes within the WECC consist of each of the three major California utilities and EOR in California, the PNW, Rocky Mountains, Southwest Desert, Baja California, British Columbia and Alberta.

The Monthly NARG model would then be run for each of the generation/temperature-hydro vintage scenarios to determine the cushion between supply and demand for natural gas in each month of the futures years chosen, for example, 2005 and 2010 for each demand zone. This modeling would determine whether for any demand zone for any weather-hydro vintage there are shortages or near-shortages in either 2005 or 2010, as we suspect will occur in the absence of significant natural gas infrastructure upgrades. Of particular interest will be the question of whether the months with the smallest surpluses are in summer or winter and if these qualitative results vary with the generation scenario. Plotting these monthly results in a cumulative distribution function fashion would provide a visual display of the results. (That is, plotting the level of surplus from each vintage/year *vs.* the probability of that level of surplus being observed for each month.) If there are even near-shortages (level to be determined) predicted in any months for any of the combined temperature-hydro vintages, then it is recommended that the analysis proceed to an iterative run with the PROSYM model. In addition to other refined input data estimates from NARG, this second series of runs would include the average daily amount of gas available in each pipeline for the electric generators by month by temperature-hydro vintage by weather zone and, finally, by generation scenario for each of 2005 and 2010.

Proposed Production Cost Model Iteration

PROSYM possesses the capability to model selected gas-fired units that are all connected to common pipelines with user-specified levels of limited fuel supply, and the model can specify alternate fuels, if any, for each of these units. To complete the analysis, this capability in PROSYM will need to be called on through modified data inputs to produce accurate electric system simulations in the presence of limited natural gas availability. Since during the course of a month there is quite a variation in fuel use both between days within a week and between weeks, it is to be expected that if NARG predicts any “close calls” on a monthly average basis then actual curtailments and fuel switching will be seen in the PROSYM modeling. PROSYM also possesses the capability to predict shortage impacts on electricity prices, so such clear effects should be well modeled in PROSYM. Finally, PROSYM will forecast demand for alternate fuel and, assuming the necessary data are provided, the emissions resulting from its use.

Final Data Collection and Assessment

The final results of these vintage-specific simulations of the nominal gas/electric system will provide estimates of the probability of demand outstripping the regional gas supply in each month. The electricity price effects of actual curtailments will be estimated in PROSYM, but the price effects of tight but adequate natural gas supplies could be quite profound in their own right. The results from NARG modeling as they are re-analyzed in the PROSYM rerun may help determine the significance of the amplification of gas shortage/scarcity effects due to daily demand fluctuations over the course of a month. This may, in turn, encourage further modeling with the system described above, and/or with the Gas Storage model currently under development at the CEC, to better study these effects.

Sensitivity Studies and Scenarios

If there is a finding that there is plenty of gas supply, even in the high-electric-generation scenario's highest use months with the least favorable weather-hydro vintage, then further study may be limited to sensitivity cases associated with, *inter alia*, large pipe breaks, loss of nuclear generation, or increased demand that might be associated with lower retail electric prices. If, however, the findings suggest a real likelihood of scarcity or shortages in the decade, then intermediate years between 2005 and 2010 and beyond 2010 may be appropriately simulated to see the trend in fuel curtailments over the course of the period. Studies to determine appropriate infrastructure enlargements or other responses, such as increased used of backup fuel, could then be undertaken as appropriate.

TASK-SPECIFIC DESCRIPTION OF PROPOSED METHODOLOGY

In this section each of the activity boxes listed in the process diagram (Figure 2) is discussed. As noted in the key assumptions note presented toward the bottom of the diagram, we envision the first application of this methodology to be the-business-as-usual scenario. This application would include:

- Most likely demand forecast;
- Expected economic growth and
- Expected fuel prices as computed from the most recent CEC assessment.

Usually, the appropriate emphasis for the first application would be on a forecast scenario that might result in reasonably robust gas demand to test the capability of the gas supply infrastructure.

Non-Electric Generation Demand Forecasting

We first discuss the Demand Analysis Office activities through the process flow diagram, Figure 2 with Data blocks (DBs) 1 - 7, Formal Model modules (FMMs) 1 - 6 and Informal Model modules (IMMs) 1 - 4. These activities are found on the left side of the diagram. The products of this element of the overall process are envisioned as monthly projections for each of 9 years from 2002 through 2010 by weather vintage for both gas and electric demand as indicated by the horizontal banner across the top of the figure.

California Gas and Electric Forecast

To reflect weather variations in these forecasts will require use of a California weather history for temperature and humidity by climate zone, as portrayed in DB 1. The recommended approach to producing the California electric and gas energy demand forecasts, as graphically portrayed in FMMs 1 through 4, is to employ those data in the sector-specific methodologies now in use at the CEC, reviving some of their now-dormant capabilities, and running them for each historical year of temperatures; *i.e.,* each temperature-vintage from 1975 to 2000. The residential and commercial buildings models (FMMs 1 and 2) produce annual outputs by climate zone combined at the service area level with demand from non-weather-sensitive end-uses (IMM 3 and FMM 5). The weather-sensitive unit-specific demands normally assume long-term average weather. These unit energy consumption (UEG) levels for the weather sensitive end-uses will be scaled appropriately by the temperature vintages for each climate zone using the appropriate weather parameter; *e.g.,* annual CDDs for air conditioning in commercial building. Thus, for both the residential and commercial buildings forecasts, a set of forecasts will be needed for each weather zone for each year for both gas and electric end-uses.

Since the industrial and non-building commercial loads (FMM 3) are assumed not to vary with weather, they are vintage-insensitive and the "normal" forecast for those sectors for each service area will suffice for all annual weather vintages. The agricultural electricity demand in the form of irrigation energy consumption (FMM 4) does vary with precipitation levels, though not temperatures. Vintage-specific agricultural electricity demand can be estimated and employed in the modeling, if the CEC weather database includes precipitation (DB 2).

Annual (and monthly in some sectors) weather vintage-specific gas outputs from these forecasts would be allocated monthly in a modest load allocation model to be constructed and provided as input to the Monthly NARG model under development (FMM 3).

The electric sector forecasts will then be used as inputs to the HELM model to develop the annual peak load for each weather vintage for each year (FMM 5). The HELM annual and peak load outputs would be then allocated monthly using historical monthly shares (DB 7) to produce the monthly peaks (IMM 4). The vintage and future year specific sets of monthly forecasts of total electric energy and peak load would then be incorporated into an existing model (FMM 6) to provide forecasts of hourly net energy for load including additional factors like system and off-system losses. These hourly California loads by service area by vintage would then be conveyed, along with PNW loads as discussed in the next subsection, to PROSYM (FMM 7) for incorporation in electric utility simulation. Such electric load shape spreadsheet models (and more extensive models) exist, but more refinement will probably be needed to allocate accurately the load among the various months as a function of weather.

PNW Electric and Gas Demand

We believe that the necessary annual forecasts of electric and gas demand and monthly historical weather data are available in the PNW, as portrayed in DBs 3 -5 of Figure 2. The annual electric forecasts will consider the entire region and will be self-consistent. As discussed *supra*, the non-EG gas demand forecasts may be less coherent but the best available should be gotten and used. If necessary, both sets of forecasts would then be disaggregated into monthly fractions based upon average demands and then further adjusted for historical heating degree data as shown in IMMs 1 and 2. Undoubtedly, some statistical analyses will be required to establish satisfactory functionality with heating degree days from the vintage weather years. The chore of accurately estimating this functionality is likely to be aggravated by the growing saturations of gas and electric space heating due to switch-out of oil heating appliances, since – all else being equal – higher space heating saturations increase weather-related load responsiveness.

The vintage-varying monthly gas results would then be split among the NARG PNW load nodes (IMM 2) and provided as input to FMM 8, the NARG Monthly model. The vintage-varying monthly electric forecasts would be input to FMM 6, the Demand Analysis Office model forecasting net energy for California electric load. Some specializing modifications would undoubtedly be required for FMM 6 to project PNW hourly loads accurately. Once produced, the PNW hourly loads would then be used as inputs to the PROSYM modeling (FMM 7).

One final correlation <u>not</u> explicitly taken into account in this risk assessment is the dependency of Direct Service Industry (DSI) load on ample hydro availability. In the past the DSI load could be greater than 4,000 average MW and would be used almost constantly without hourly, daily or seasonal variation throughout the year. Most of this load was consumed by alumina smelters that would pay quite modest prices for surplus regional electricity as long as surpluses were available in the PNW. If the hydro surplus diminished or became a deficit, DSI loads would be the first regional loads to be curtailed after all non-firm sales to California.[29]

[29] Pursuant to federal law, if an electricity shortage develops in the PNW, all BPA out-of-region energy sales can be pulled back with 30 days' notice and converted to energy exchanges.

This process was, in previous years, structurally similar to the use of secondary fuel oil in California in cases of natural gas shortages, and just as in California, this escape valve for weather-driven variations in supply (in this case hydro generation) is disappearing. Due to the increased price of electricity, the alumina smelters are closing as their ten-year renewable contracts with BPA come up for renegotiation. We assume for simplicity in this methodology that DSI loads will diminish to such an extent by 2005 that it does not significantly affect the gas balance in our California-centered analysis. However, this assumption needs to be verified by contacts in the PNW. If a sizable non-firm DSI electric load is expected to persist, then an adjustment for DSI electric load as a function of PNW water conditions will be required. Should such an adjustment be deemed needed then a coordination of outputs from IMM 1 and DB 9 would be required to reflect the curtailment of DSI electric load in instances of significant drought.

Thermally Enhanced Oil Recovery Natural Gas Demand

The sixth and last block of demand data (DB 6) refers to the demand for natural gas from TEOR in California. This is a non-weather-responsive demand that is likely not to be subject to great uncertainty or variation over time. Thus, it is more of a simple gas balance issue that must be projected monthly and provided as input to the Monthly NARG model under development (FMM 8).

Electric Generation Natural Gas Demand Forecasting

PROSYM (FMMs 7 and 9) is the current production cost model of choice at the CEC. It is run in an entire western interconnected region format simulating the entire region hourly for each year of interest using an exogenously chosen set of generators, fuel prices and availability, contractual requirements and loads. As indicated *supra*, each weather vintage needs to be simulated for each future study year to capture the variation in EG gas demand. In this section we will discuss the data block inputs (DB 8 - 10) to the PROSYM model and the net energy for load input (FMM 6).

Net Energy for Load Input

PROSYM requires hourly loads for all of the Western Region. The PNW and California loads would be for each of 25 vintages for this risk assessment methodology. The remaining loads, including those in British Columbia and the ISW, would be the same average weather year forecast that would be used every time a new weather vintage is employed in the model.

Hydroelectric Flows

PROSYM needs a series of hydro cases (DBs 8 - 10) to implement the risk methodology, one for each vintage, and the simulations need to be consecutive with the vintages to retain the historical frequency of drought sequencing.[30] The model will use the hydro to flatten hourly loads where possible, consistent with minimum and maximum flow requirements. The flatter the load, the lower will be the overall gas demand. Thus, the PROSYM algorithmic approach minimizes gas use with available hydro resources.

High/Low Resource Plans

PROSYM also requires as input a scenario of future resources (DB 11). We agree with Staff that a variation in assumed number of new resources is an important variable in gas demand. The CEC's selected high and low new resources cases serve this purpose.

Interestingly, results from some available simulations suggest that the marginal impact on reducing gas demand due to increasing resources may be reaching a point of diminishing returns. The more that gas-fired existing steam boilers are displaced by more efficient combined cycle units, the lower is the gas demand – unless and until the more efficient gas fired units operate for so much longer that they incrementally consume sufficient fuel to equal the gas savings caused by displacement of the more inefficient gas units. Studies to date suggest that some reduction in gas consumption in the region results from the presence of still more high efficiency combined cycle units; however, the sensitivity is becoming much less pronounced as incremental units are added. A recent study conducted by SERA

[30] This consideration increases in importance if the PNW DSI load remains and varies with hydro conditions.

staff found that the reduction in California EG gas demand was only about 70 mmcf/d when the number of assumed new generators was doubled from about 6,000 MW to about 12,000 MW.[31] These results suggest that the increase in efficiency of gas use due to more new CC generation (the average heat rate of all merchant and utility gas-fired units in this study shrunk from about 8,700 to 7,400 Btu/kWh) was mostly offset by increased gas-fired generation due to the lower running costs of the more efficient gas units. The actual generation increase observed in annual gas-fired generation totaled approximately 10,000 GWh. The range in projected level of new generation that was considered in this study (*i.e.,* from 6,000 to 12,000 MW) appears in hindsight to represent a reasonable bounds on the range of uncertainty surrounding expected new generation.

<u>NARG Modeling and Final Methodology Iteration</u>

The final few process blocks found on Figure 2 are associated with running the NARG monthly gas supply model under development and iterating with PROSYM. Major data inputs will be the data sets for the Monthly NARG model (FMM 8) for the non-WECC portion of the linked north American gas system (DB 12). These data will be the basis inputs employed in the model for those regions and will assume average weather conditions. Average hydroelectric conditions will also be assumed but as discussed, *supra*, we expect almost no loss of precision from this simplifying assumption.

A key element of the modeling is the need to preclude or minimize any new gas resources that are endogenously generated within NARG. Naturally, postulating new gas supplies would solve any erstwhile shortage. It appears that the model can be "fooled" into looking at the supply-demand balance without altering it, at least in the short term.[32] Care will need to be taken to assure that unplanned supplies are not endogenously generated in the modeling.

As indicated *supra*, if a shortage or monthly near-shortfall should be seen in the NARG modeling, then the PROSYM modeling would need to take advantage of the PROSYM

[31] Based upon year 2000 SERASYM runs done for the CPUC's PG&E hydro divestiture EIR.

[32] Expansion of the time to complete new generic resources is one method employed in other resource planning models to "lock in" a given future resource plan.

capability of modeling limited fuel resources (FMM 9). We recommend that daily gas supply limitations be placed on pools of generators throughout California and the PNW and that these limitations be varied at least monthly and possibly more frequently depending upon the form of the inputs to the Monthly NARG model under development (FMM 8). Net gas supply inputs to PROSYM would need to be estimated after all other gas demands have been satisfied. A new informal modeling module not displayed on Figure 2 may need to be produced to provide this input to PROSYM. This IMM would start with the gas supplies to the various demand nodes estimated by NARG and then, using the inputs to the NARG model from California, PNW and, possibly, TEOR gas demand (DBs 2, 3 and 6), produce the weekly - monthly net gas availability estimates for PROSYM. The degree of complexity, or even the very need, for this module would depend upon the first pass outputs from the NARG model for the years considered.

METHODOLOGICAL SHORTCUTS FOR PRODUCING PRELIMINARY RESULTS

The CEC staff has requested that consideration be given to how the initial cut at implementing this methodology could be limited or streamlined. Several good results would arise from the successful implementation of this methodology in two-steps starting with an initial rough cut.
These include:

- Acquiring a more heuristic understanding of the overall modeling, data and policy issues, from which a refined and more functionally efficient methodology would be derived;

- Permitting more effective focus on the most important remaining methodology and data collection challenges, including the possibility of procuring outside contractors for performance of selected, specialized supplemental tasks; and

- Providing an exemplary interim product using a lower level of personnel commitment; thereby, fueling staff enthusiasm and potentially freeing the additional needed staff resources to complete the full assessment.

This "proof-of-concept" study would be an effective way to see that all the methodological pieces have been identified and accommodated and to highlight data weaknesses that need further emphasis. The management insights garnered during this interim study would also more clearly show the level of personnel commitment needed to complete the entire project.

There is no precise way to determine how much of the analysis can be postponed and still achieve the goals of an interim study. The "art" inherent in this approach is determining what data assembly and modeling activities can be appropriately postponed until the second phase of the assessment. This section provides the requested discussion and recommendations and includes cautionary considerations about what level of "simplification" will still provide a meaningful product.

<u>Some Possible Forms of Simplification Appear Inappropriate</u>

Two possible ways to reduce the total amount of time and effort are to combine the worst case hydro and weather conditions observed from historical years or to select one or two "worst" years for assessment. Either simplification approach would reduce the model run times about a factor of ten and reduce by a lesser amount the time and effort required to produce input and handle, sort and manipulate intermediate and final results. In our experience, with the advent of workstations the model run time is the least of the important concerns, even if (as with the PROSYM model) the full slate of simulations might require the better part of a week to run. The effort potentially devoted to data manipulation and handling of results are much more labor-intensive issues and important to consider. However, the more accurate and valuable approach for many reasons is to employ the recommended methodology comprehensively, and very judiciously trim and simplify selected analyses where possible without great loss of accuracy.

Analytical trimming and simplifying should be concentrated in those topic areas with the least impact on the overall accuracy of the product. In order of impact on the projected accuracy of the forecasted net gas balance, we list:

1. Gas supply resource variation anywhere in the region;
2. Temperature-driven demand effects (probably most significant in California followed by the PNW);
3. Hydroelectric generation effects (with the PNW clearly being the most significant, California second, and the remainder of the Western Region far behind); and
4. Electric Resource Variation within reasonable bounds.

Gas supply resources are the most important. Meaningful new gas supply resources would likely be measured in 500 to 1,000 mmcf/d increments that would clearly have an enormous impact on the overall results of the risk assessment. Non-EG demand has always represented the lion's share of overall demand and since space conditioning end-uses have all represented the largest share of that demand it follows that next in importance to gas resource modifications would be temperature driven variations. Hydroelectric generation variation and changes in electric resources comprise the least important factors based on modeling knowledge currently extant.

The Worst Year Is Probably Unknown

It is a simple matter to look up in Energy Information Agency (EIA) data the lowest hydroelectric year or to refer to the year of greatest level of higher-priority natural gas use.[33] Uncovering the recent years with the most HDDs or CDDs should also be simple. These data, of course, are available at the state level and can be aggregated to the regional level. Nevertheless, their use is immediately suspect. The actual gas demand in any of these historical years is inappropriate for use in forecasting *per se*, due to the structural change in demand that has already occurred and will have further progressed by the middle of this decade. We have to model these weather-related parameters in a future year in order to assess their impact in that future year. Thus, most of the modeling requirements remain, even in a truncated, worst year assessment. Beyond that, the issue is: what criteria should be used to select the "worst" year or years? Unless a more complete assessment has been done, the year selected may not be the most severe annual test, and such a guess would be too uncertain to satisfy the level of accuracy that responsible policy analysis demands.

Pancaking Worst Case Features Is Overly Conservative

A guaranteed method of providing a conservative approach is to select and combine the most severe temperature and hydro vintages in each region into a single worst case. It would almost certainly be a "worst" case, but it would be so highly pessimistic as to be unreliable when balancing benefits/costs and environmental impacts, as one would when determining whether there is sufficient "slack" pipeline capacity or whether building an LNG facility would significantly enhance gas supply reliability. Without the context of a range of annual results assessing risk in an accurate manner that is meaningful to policy analysis is very difficult.

Possible Preliminary Simplifications in Non-EG Demand Forecasting

A number of data collection and use simplifications are already found in the recommended

[33] Some inaccuracies seem to now be present in these EIA data due to the impact of California electric restructuring.

complete methodology, including holding BCH and ISW demands fixed and tentatively holding DSI demand as invariant. Certain other data elements can be simplified on a selective basis as described hereafter, but it is possible to consider a more fundamental change in the use of the California modeling that might also suffice for the first cut.

Modeling Simplifications

As an interim measure, perhaps, a strictly statistical approach could be used to supplement the base case forecasts that would estimate the impacts of weather variations on an annual or monthly basis. This statistical assessment could be done at any geographical level of jointly known historical demand and weather. It would assume that the structure of demand in all sectors is invariant from past to future and so this approach has the same limitations that first encouraged use of end-use demand models at the CEC. Thus, use of this simplified approach should be limited to as few sectors/fuels as possible. To reduce estimation errors caused by structural changes in demand, the estimates should be derived from as recent a data set as the statistical degrees of freedom associated with the estimation process would responsibly permit.

Elimination of consideration of agricultural demand variation with precipitation would be a much less draconian simplification than going to an extensive statistical approach to forecast vintage-specific annual energy demands. Similarly, a simple statistical allocation of demand by months by vintage also could accelerate the effort with only limited loss of accuracy, since the total energy forecast for each weather-vintage-year would remain the same. The Demand Analysis Office's proposal to use monthly gas load factor data from the LDC demand submittals appears to be an excellent suggestion for the preliminary study.

Data Simplifications

Reducing the number of end-uses evaluated for temperature responsiveness could also accelerate the forecasting process. Ignoring the HDD impact on water heating could reduce the overall burden, as would eliminating consideration of weather-driven gas demand variation on swimming pool heating and gas air-conditioning UECs.

Possible Preliminary Simplifications in EG Demand Forecasting

Several options present themselves in the EG forecasting arena, including both PROSYM modeling simplifications and data use simplifications.

Modeling Simplification

There is a choice how precisely the various hydroelectric facilities are modeled. For example, the PG&E system can be modeled from as many as about 70 units to as few as a single station.[34] Since we are interested in total energy use, the manner in which the hydro is dispatched will only have a secondary effect on the total level of gas use. That is, the total amount of hydro energy will remain the same and total gas energy use will only change due to the relatively minor changes in the dispatch patterns of other units resulting from the changes in operation of the hydro systems. Thus, for the preliminary assessment, consideration should be given to collapsing all the PG&E hydro into a single generating station and using the CPUC EIR results from UPLAN vintage simulations monthly.

Data Simplifications

Two potential data simplifications appear potentially feasible: using only one resource plan, and eliminating the vintage variation in BCH hydro. By limiting simulation to only the most likely resource plan, the total number of simulations will be reduced by 50 percent and the labor involved with handling those extra cases would be reduced as well. These reductions would be proportionately reflected in both the NARG modeling and in the PROSYM modeling. As indicated *supra,* in normal weather the variation in demand from a quite low to a quite high resource plan is about 70 mmcf/d; thus, consideration should be given to using only a middle-ground assessment in the preliminary assessment and accepting the imprecision that results.

A simplification that would reduce the level of effort required of the PROSYM modelers would be to assume average BCH hydro conditions for all weather vintage. Some results from simulations of the region suggest that the impact of BCH hydro variation on the

[34] For example, the ELFIN modeling for the Electricity Reports in the 1990s employed such an approach

operation of the Western Interconnected Region would be sufficiently modest that omitting it from the initial cut should be considered. This would eliminate the need to both collect the necessary vintage specific data and format it for input to PROSYM.

Possible Preliminary Simplifications in Gas Supply Forecasting

As indicated in the previous section, eliminating the recommended use of a high and a low electric generation resource plan halves the total number of NARG simulations required. It is probably premature to attempt to identify any modeling simplifications specific to the monthly version of NARG whose development is still being completed.

Concern was voiced by the gas supply modelers as to the availability of monthly data for not only the Western Region but also the remainder of the interconnected region of North America evaluated in the model. As discussed with respect to the hydro modeling, the first concern of this preliminary analysis is to estimate the intrinsic gas supply annually. Thus, an approach using annual data along with even casually estimated monthly gas shapes for the other regions is recommended, at least beyond the Western Region, to provide a "full" data set. Areas outside California and the PNW in the Western Region should have more accurate average monthly shapes, if possible, since they will more directly impact upon the adequacy of gas supplies to California. However, this concern and the need to acquire accurate average data for the model are independent of this risk assessment and intrinsic to introducing a monthly model for use in California energy policy work.

INTERPRETATION AND USE OF RISK ASSESSMENT OUTPUT

The ultimate outputs of the assessment for any future year are the sets of monthly vintage outputs of gas supply and demand centered on California demand nodes within the WECC. The supply information is assumed to come from the Monthly NARG model still under development while the demand information comes from a combination of results from the Demand Analysis Office models and PROSYM outputs produced by the Electricity Analysis Office. I assume that the demand information will be best gathered in summary form from input set echos from the NARG model for the demand nodes of interest. For this discussion we assume that the Monthly NARG model currently under development will have been limited in its endogenous behavior so that it will not respond to calculating a shortage of natural gas by postulating the presence of additional production from existing or new supply regions or by increasing the capacity of gas transmission lines beyond supply enhancements that were exogenously input to the model. Thus, the "surplus" natural gas available on a monthly-vintage basis will be available and compiled from the NARG Monthly model for each yearly run for each demand zone.

Qualitative Conclusions from Output of First and Final Modeling Passes

As portrayed in Figure 2 and otherwise discussed in this report, the initial pass of the execution of the modeling process (*i.e.*, excluding FMM 9) will be the execution of the NARG Monthly model utilizing as input the EG gas demands forecasted by the PROSYM model without consideration of natural gas or other fossil fuel supply limits not otherwise intrinsic to the standard PROSYM modeling inputs. Thus, PROSYM could find itself employing more gas for EG than would actually be available due to possible endemic shortages or the vagaries of the weather. Large shortages would become evident during the running of the NARG model, either because inadequate gas supplies would be identified in selected months or only negligible excess supplies would remain after full satisfaction of average daily demand over the course of a month.[35] Note that because of the difference in time-scale between the NARG monthly gas demand model and the hourly PROSYM model, even significant residual supply at the end of the month could conceal actual shortages within a given month. This would be especially true during "shoulder" months, when the weather,

[35] Recall the simplifying NARG modeling assumption that gas demand is equal throughout the month at its average daily level.

either through large temperature variations and/or its effect on hydro generation, might be substantially different between the beginning and the end of the month. Thus, excessive usage in one period could be averaged with much lower usage during the remainder of the month, erroneously suggesting that gas supplies were forecast as adequate throughout the month when, in fact, shortages for some fraction of the month were seen.

Initial results for each future year to be evaluated would consist of [~25 weather vintage years] X [12 months/yr.] X [two resource plans] = 600 monthly net gas supply balances for each demand node or combination of demand nodes. Splitting these monthly gas supply balances by resource plan would result in about 300 monthly data points that could be ordered by vintage in a 12 by 25 matrix and color-coded to identify varying amounts of surplus gas for each individual California service area, for all of Southern California, and for all of California. These results would be compiled for each future year studied. Studying these preliminary results for the future could yield the following initial insights:

- Geographic sensitivity, including possible shortages or small supply margins, might be observed in the San Diego/Baja area or all of Southern California. This would likely be attributable to transmission limitations. Any shortages observed throughout all of California would more likely be attributable to regional supply limitations;

- Electric generation resource planning insights as to the sensitivity of demand balance to EG resources (*i.e.*, would increased numbers of more efficient gas-fired resources mitigate or exacerbate any supply limits?);

- End-use demand issues related to months and seasons of most frequent shortage (January or possibly August will likely be the times of least abundance);

- Insights into weather cycle effects and persistences of shortage from year to year; and finally;

- Assessment (from predicted differences between future forecast years) of whether the overall demand/supply balance is getting worse or better as the overall energy system is projected to evolve.

If there is essentially no tightness of supply in any month in any of the years then the second phase of the analysis need not go on and then conservative (i.e., worst case) probabilistic estimates can be computed. However, assuming that at least some tightness in net supply is observed – especially if any actual net shortages are observed in any months – then the modeling iteration round will be required. As discussed *supra*, limits on gas supply will need to be imposed on groups of EG stations served by common supply sources, including the combined Baja/San Diego stations and all of the Southern California stations. Other stations will need to be tied to their gas supply sources as well. Information from the NARG model would be used to develop maximum monthly estimates of gas availability for the individual gas unit pools. The Electricity Analysis Office would need to determine which stations have secondary energy sources and the cost extent of those secondary supplies.

We recommend that PROSYM be run using the daily fuel limit feature by gas supply pool to make it possible to identify shortages that arise during a month and especially during individual daily or weekly periods. This is also a realistic modeling of the practicality of fuel switching, which can be most feasibly performed over a twenty-four-hour period during which the unit can be shutdown for the fuel switch-over. Fuel switching within the California system will probably be possible for only a few boiler units in San Diego and San Francisco that, along with other oil-fired units, would have to pick up as much as possible the electricity shortage created by the back-off of other California gas units without adequate gas supply or fuel switching capability. Other gas-fueled stations within the WECC, such as Sierra Pacific Power units in the Reno area, can switch to stored propane using a propane-air mixture, but this capability is so small as to be expected to have little benefit in California.

The maximum response that we expect to be observed from the modeling of limited gas fuel may be the switching from cheaper instate CC generators that have no alternative fuels to more expensive out-of-state generators with high priced coal supply contracts, poor efficiencies or oil firing. Natural gas shortages as they were reflected in generator and fuel switching would be reflected in elevated electricity prices forecasted by PROSYM whether or not simple cost bidding or more extensive scarcity bidding algorithms are employed.

Risk Measures Produced by the Gas Modeling

The probabilistic interpretations of the modeling results are quite straightforward because the approach proposed automatically captures the most important covariances between temperature and hydroelectric effects and between regional weather effects. Assuming that the past weather is prelude to future weather and that the weather impacts on gas demand follow a Gaussian distribution (although see discussion of testing this assumptions, *infra*), we would assume that the results are unbiased samples from an underlying normal distribution.[36] The monthly or annual average demand at one or any combination of nodes would be the simple mean and the standard distribution, σ, would be $[\Sigma(D_i - \mu)^2/(N-1)]^{1/2}$ where D_i is the demand in the "ith" vintage, μ is the average demand over all vintages and N is the number of vintages. With this framework the outliers are clearly established and can be displayed as shown on Figure 1. For example, a one in twenty year occurrence of demand would be average demand plus 1.65σ. It would be expected that the monthly variances would be considerably larger as a percentage of average monthly demand than would the annual variance and would be especially large during the shoulder months.

On the same probabilistic plots upon which the demand results are presented could be drawn the gas supply as a single horizontal line assuming the straight (deterministic) output of the NARG monthly model. Where the sloping demand line intersects the supply line (indicating that a shortage has been identified), a vertical line dropped from that point of intersection is the graphical computation of the likelihood of gas shortage as can be read off the value on the abscissa. Naturally, several years of demand plotted as a family of sloping lines can be compared with a family of horizontal lines representing growing deterministic supply to ascertain the tendency in the future. This would probably be most effective as monthly plots for the key summer and winter months as determined by the results of the analysis.

If scarcity or shortage is discovered in the unconstrained case then the results of the iterated version of the modeling approach could be employed to modify the supply line. Augmentation of supply would be equal to the reduction in gas demand achieved in PROSYM through gas supply limitation and substitution that would be, effectively, further supply.

[36] Assuming that we have encompassed sufficient years to capture weather oscillations and ignoring possible civilization-caused weather changes as discussed in earlier sections of this report.

Goodness of Fit to Normal Distribution

The Normality of the results is potentially an issue that will become more self evident upon review of the results. For more precision in the risk estimates for unlikely events at the tails of the frequency distributions, it is possible that another distribution could provide a better goodness of fit to the results. Historically, hydroelectric generation available to California clearly follows a Lognormal distribution with the mean energy available significantly more than occurs in the 50 percentile (median) case. EG gas demand, all else being equal, should tend to have a similarly shaped probability density function assuming that gas-fired generation would tend to replace hydro on a one-for-one basis. On the other hand, heating degree and cooling degree data probably tend to act more Gaussian although the data never go negative just like for hydroelectric generation.[37] Thus, for the combined demand results a Lognormal distribution could provide a more accurate fit to the data. If so, its use would be nearly as straight forward as using a Gaussian distribution since the logs of the variates (in this case the demand vintages) in a Lognormal distribution would be Normally distributed. The extra effort required would be to translate the model outputs from regular values to their logs to determine the resulting Normal distribution and then translate back the logs of values into regular values for reporting of results.

[37] A key difference between the Normal and Lognormal distributions is that the Normal distribution ranges from $-\infty$ to $+\infty$ while the Lognormal ranges from zero to $+\infty$.

NEXT STEPS TO CLARIFY MODELING AND DATA COLLECTION ISSUES

Some concerns have been raised by the Electricity Analysis Office (EAO) staff during review of an earlier draft of this methodology report.[38] These concerns are technical and/or workload related. This section lists these concerns and briefly addresses each. Where appropriate, actions are suggested to allay or clarify those issues.

1) *Per the report, the methodology suggested provides a better distribution of hydroelectricity energy because it is based not upon observed generation during the past 25 years, but on forecasted energy given historical water conditions and projected flows given anticipated operation of the hydro system (e.g., supra, p. 21). These forecasts are available from BPA for the federal component of the Columbia River system, but do not seem to be available for the remainder of the Northwest, including British Columbia, and California (PG&E does not provide these estimates. Moreover, operating constraints imposed on the California hydro systems are apt to change should PG&E be allowed to divest itself of its hydroelectric facilities.) EAO staff questions whether the manufacture of such data, even if possible, would be a substantial improvement over the use of historical generation values, with modifications, if necessary, as suggested by the operators of the hydro systems in California and British Columbia.*

   This comment is compound in nature and each particular issue will be answered in sequence. However, it can be inferred from the comment that the EAO staff is in agreement with the key basis precept of this methodology of employing a range of hydro conditions reflective of observed precipitation and temperature patterns of the recent past. The modeling of the Columbia Mainstem (*i.e.*, the portion of the PNW mentioned in the comment) does not constitute all of the PNW hydro generation but it does represent most of it. Generally, we believe that non-trivial non-Mainstem portions of the regional hydro (*e.g.* hydro west of the Cascade Mountains) are considered at the same time as the Mainstem for analytical purposes such as determining total unconstrained water flow. Even were this consideration not true in all cases the impact on the accuracy of the analysis is so slight that employing either average conditions for the non-Mainstem hydro for all vintages or assuming conditions proportional to the monthly generation from the Mainstem for the remaining generation in

[38] Email from David Vidaver, EAO to Todd Peterson, Natural Gas Office dated December 16, 2002.

the region would be an acceptably accurate first model effort.

The comment with respect to the BC Hydro system is partially addressed in the report section of possible first phase simplifications (*supra*, p. 41). There, it is suggested as a first step simplification that an average BC Hydro future generation case be used for all vintages. We understand that it is not appropriate to use the actual, historical generation for the final quarter of the 20th century due to enlargements of the capacity of the system during that period. Consistent with our experience with the SERAM II model, we believe that modeling of future water years for the BC hydro system over 30+ vintages of observed precipitation and snow melt patterns are routinely used and are assessable especially by a governmental agency like the CEC. Verification of these understandings would be a useful immediate action on the part of the CEC staff.

The PG&E system was extensively studied during the assessment of the environmental impacts of the proposed hydro system divestiture in the CPUC proceeding. Precisely the information suggested for use in this report was produced during the substantial modeling effort reported upon in the initial EIR report (*supra*, pp. 21 - 22). There may be some variation possible in the future operation of the PG&E system were some of the proposed PG&E bankruptcy Plans of Reorganization accepted.[39] But as seen in the results of detailed modeling discussed earlier (*supra*, p. 22), the total amount of monthly hydro energy would not change significantly and the modifications in operations would be second order effects that could be safely ignored.

2) *Regarding 'Proposed Production Cost Model Iteration (supra, p. 28)': While Prosym allows users to impose fuel constraints on individual power plants or sets of plants, this functionality is intended for asset owners who have the information necessary to accurately specify said constraints. CEC staff does not have access to this information, which includes, at a minimum, delivery contract terms and conditions and storage agreements and behavior.*

It is important to note that this data issue only arises if and when it is determined that operation of the EG system in the WECC results in scarcity of natural gas during some

[39] Execution of a confidentiality agreement by the CEC may be required before the CPUC can convey the most detailed data.

vintage months. It is part of a second pass in the modeling process and is not an immediate issue under any circumstances. Thus, it should not affect a decision as to whether or not to initiate the methodology effort. On the other hand it is an interesting question whether or not some limited fuel modeling should now be present in the WECC modeling by the CEC even absent this methodology. For example, looking at selected gas transmission import limits such as those into San Diego might well currently deserve higher level production modeling resolution lest another, surprise curtailment occur such as happened in late 2000 and early 2001.

The more general issue is whether or not gas supply information, analogous in many respects to that customarily acquired and employed for coal fired units modeled in PROSYM, is now accessible for the new generation of gas-fired Exempt Wholesale Generators (EWG). Historically, the utility supply gas procurement and transmission contracts were always available from the FERC unless the contract involved two municipal utilities which was an uncommon event. In those cases the contracts were normally public and could be gotten from one of the parties. Now and in the future, the gas contracts between EWGs and their gas suppliers, especially with entities like Calpine that can be simultaneously both entities, the likelihood of getting specific supply information will be more difficult. This limitation may not matter, however, except in rare cases where the EG is adjacent to the gas production. Otherwise, overall gas production and transmission limitations will dictate how much gas is available and the issue then becomes who is curtailed? In these quasi *force majeure* situations it is anticipated that the destination of specific gas supplies will be allocated by a priority system regardless of nominal ownership of the gas.

3) *EAO staff is currently responsible for providing estimates of PNW electrical loads. It lacks the expertise, however, to create weather-adjusted load estimates for the region (supra, pp. 25 - 26). Given the changes in the weather-load relationship over the years in the PNW as a result of the increased use of electricity for heating needs, staff believes that this would be a difficult set of values to accurately estimate.*

We agree that doing accurate weather adjusted vintage forecast for the PNW is a challenging task but a very important one. Based upon the differences in responsibilities and capabilities of the respective CEC staff organization, it may be prudent to consider shifting responsibility for this element of the analysis to the Demand Analysis Office (DAO) as is assumed in this methodology (*supra*, Figure 2). This part of the methodology is so important that it should be promptly initiated. We recommend that the first actions be to survey what information is available from the various entities in the PNW for both gas and electric demand. Depending upon what data sources are identified, the work implications for DAO staff will be clearer. As previously indicated, we anticipate the greater difficulty will be found in developing gas demand forecasts since the regional sources of data and projections will be more fragmented.

4) *The methodology proposed requires estimates of monthly peak and total electrical loads for each of twenty-five weather-vintages. It is not obvious to EAO staff why this is necessary to estimate the probability of gas loads exceeding a certain value. The entire probability distribution for hydro energy is not necessary, only the probability of available energy falling below specific values, which can be easily estimated (supra, pp. 13-14). It is not obvious to staff why similar 'one-sided' analysis can't be used for the temperature variation, assuming that the covariance between available hydro energy and temperature (and load, thru changes in agricultural pumping needs) is accounted for.*

This comment introduces two distinct issues and in so doing seeks ways to reduce the analytical burden and make the application of the methodology more efficient and economical. One issue is how much value is gained from forecasting monthly peak loads and total electricity demand. Clearly a model that is intended to provide estimates of gas shortage on a weekly to monthly basis must have reasonable accurate total energy projections. However, we agree with EAO that the need for monthly peak loads is less apparent. Peak loads are useful in fabricating the hourly electric load shape for the individual months by load center that then affects how the electric system model chooses to satisfy that hourly load.[40] It is a second order effect compared to the total amount of electric load required for each month and has an impact on overall monthly gas demand only via the generators whose operation PROSYM selects to satisfy the load. The proposed simplification mentioned under the section Model Simplification (*supra*, p. 40) proposes a simple allocation of demand which would result in not forecasting monthly peak load and only forecasting monthly energy and annual peak load.

[40] Once the total monthly energy and either peak load or load factor is specified then the other factor is automatically specified and a load shape is produced by many load building models employing historical load shapes for the month.

The other major issue introduced in this comment has to do with, in effect, only doing a "worst side" sampling of vintages and not considering the vintages that result in substantial surplus natural gas. This proposal has several apparent difficulties and does not appear to offer any apparent benefits other than reducing the number of PROSYM/NARG Monthly Model simulations by a factor of two and reducing the amount of various outputs that have to be manipulated.

A problem that was alluded to in the comment by EAO staff was how to know which vintages are the worse, say, 50 percent. The highest demand vintages for winter heating may have associated cool summers and may have little or no correlation with hydro electric generation. An overall average temperature year may have a severe weather month during an unusual precipitation year that would not be known with modeling. Thus, without gathering substantial weather and hydro data for individual vintages and running them through the methodology, it appears uncertain that the critical months can even be selected. Further, without fully flushing out the set of vintages, it seems very unlikely that an accurate estimate can be made of the probabilities of the various levels of gas shortage.

Another issue that would arise from a sampling limited to the years perceived to be more critical is an inability to estimate the economic benefit of new infrastructure. For example, if an infrastructure is being proposed (*e.g.*, purchase of "slack" gas transmission line) then by running the methodology without and with the new proposed infrastructure expansion for each vintage the vintage specific benefits can be computed and weighted by their frequency of occurrence to evaluate the net expected ratepayer value of the investment. An accurate evaluation of the benefits of such a proposed project could not be produced without an accurate estimation of the probability distribution of each set of conditions. Overall, we think that the modest reduction in labor from the simplification of using only "critical" years is not nearly worth the loss in methodological power, comprehensiveness, usefulness and accuracy that would arise from its use.

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