DOLLAR-BASED PERFORMANCE STANDARDS FOR BUILDING ENERGY EFFICIENCY

Final Report

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Abstract

This study explores the feasibility of using an alternative costing basis for the setting building energy efficiency standards. A variety of approaches were evaluated including marginal costing and Time-of-Use rates. The implications of these alternative approaches on energy efficiency measures are also appraised.

1 EXECUTIVE SUMMARY

California's Title 24 Energy Efficiency Standards for Residential and Nonresidential Buildings regulate the energy performance of building walls and windows, lighting, water heating and HVAC systems. Under the Warren-Alquist Act, the legislature charged the California Energy Commission with developing energy efficiency building standards that were "cost effective, when taken in their entirety, and when amortized over the economic life of the structure when compared with historic practice."[1] These Standards provide powerful signals to the new construction market, and they have the power to influence the long term energy efficiency of the state's energy delivery system.

Past development and revisions of the Title 24 energy standards assumed a flat or fixed rate for energy costs regardless of the timing of the demand for energy or the type of heating fuel used. These energy costs were based upon the average $/kWh of electricity or $/therm of natural gas paid by residential or commercial consumers throughout the state. In reality, the cost of delivered energy depends upon when and where the energy is needed. This study investigates the feasibility of using a more sophisticated energy costing analysis which accounts for variations in cost related to time of day, seasons, geography and fuel type. Much of the geographical and temporal variability in delivered energy costs is due to the costs of the transmission and distribution system. It is expected that energy standards that are more closely tied to the actual variations in energy costs could better optimize the conservation of resources.

This study addresses four questions:

1. Is there energy cost information available to estimate the geographical variation in the cost of delivered energy? Will the information continue to be available in the future?
2. Is there energy cost information available to estimate the time dependant variation in the cost of delivered energy? Will the information continue to be available in the future?
3. Is there technical information available to model more accurately the variability in air conditioner efficiency as outdoor temperature varies and as cooling load varies?
4. What what would be the energy Standards impacts of using a more detailed energy cost estimating method?

To answer these questions, several approaches to determining energy costs were explored.

Rates, the published tariffs that utilities charge customers, do not adequately capture temporal and geographic variation in energy costs. Since rates are usually the same across an entire utility system, geographic variation in costs within a utility service territory are not represented. Utility rates also embody political, marketing and billing strategies. Such extraneous influences could deform price signals to the extent that they would not be useful for optimizing resource efficiency in building design.

Marginal costing offers an alternative approach. For the various energy sources, it considers the additional cost to the energy utility for providing an incremental increase in energy load. This costing methodology has the advantage of relating energy costs to the expenditures for energy and for increasing the size of the energy transportation and distribution (T&D) system on an hour-by-hour basis. The geographical variability in energy costs could be calculated if the utilities recorded and released their T&D costs by region. Currently PG&E is the only utility in California

[1] Section 25402 Division 15 California's Public Resources Code (Warren-Alquist Act)

which has made available its marginal costs on a geographical basis and these may not be available in the future under more competitive market conditions.

If marginal costing were used directly as the basis of the cost effectiveness of energy codes, this would change the economic perspective from customer-based (rates) to utility-based (marginal costs). These marginal costs do not contain fixed costs (such as interest on capital) nor do they contain company profit or return to investors. Marginal costs are lower than rates; thus a cost-effectiveness analysis of energy standards based purely on marginal costs would result in less stringent standards than those based upon rates.

Alternatively, if a societal perspective were taken, which internalizes the economic value of all the environmental impacts of energy production and delivery, the cost of energy would be substantially higher.[2] Assigning costs to currently externalized environmental impacts is beyond the scope of this study and is highly contentious due to a lack of consensus on the magnitude of the impacts and the valuation of morbidity and mortality.

Energy costing based upon customer cost is the “middle path” of energy costing between lower marginal costs and higher societal costs (including environmental externalities). This analysis adds a flat additional unit cost to the marginal costs. The resultant hybrid costing provides the same $/kWh and $/therm variation with time as marginal costs, while having the same overall cost as utility rates. This adjustment of the marginal costs up to utility rate values has been done for both the “CEC” and CEC methodology” cost analyses.

The “CEC” analysis takes marginal energy costs and adjusts them up (based on average statewide rates) to the unit costs that were employed to demonstrate cost effectiveness of the 1992 Standards. The analysis for the 1992 Standards used “flat” unit energy costs that did not change by time of day or season of the year; whereas the “CEC” analysis in this study compares two types of time-varying energy costs to flat costs.

In 1990, when the cost effectiveness of the 1992 Standards were being evaluated, the projections of energy costs in real dollars were higher than similar projections made today. The “CEC methodology” cost analysis updates the energy cost projections and adds propane costs as a separate energy source to be considered.

As a “reality check” the cost savings results are compared with those that would result using the current published tariffs (including the CTC, competitive transition charges) from the three major electric utilities and the three major natural gas utilities. Since cost data for the relatively unregulated propane industry was not available, only rates (as opposed to marginal cost data) for propane energy costs can be reported.

Three different approaches were used to develop electricity costs: 1) flat (constant) energy costing, 2) time-of-use (TOU) costing, and 3) costing correlated to temperature and time of day. The temperature-correlated cost accounts for the influence of weather on peak summer and winter loads. Natural gas and propane are valued either as a flat cost or as a cost that varies by month.

Conclusions reached on the economic aspects of this study are:

- Marginal energy costs are substantially less than average energy rates (especially for electricity). Using marginal costs as the basis of energy standards would reduce the number of efficiency measures that would be considered cost-effective.
- Marginal costs for each utility’s T&D system will likely be available in the future. Information about regional costs within a utility will likely not be available.

[2] One attempt at assigning economic values to “environmental externalities” is contained in *Environmental Costs of Electricity,* Pace University Center for Legal Studies, 1990.

- The inputs needed to develop time-varying T&D costs by utility system will likely be available in the future (system T&D costs and hourly system loads.)
- Marginal electricity commodity prices will be readily available from the historical ISO/PX prices
- Natural gas commodity prices will be readily available from FERC
- Propane is approximately twice as expensive as natural gas. The Standards should probably treat propane separately from natural gas.
- Projections of energy rates in real dollars are now substantially less than they were in 1990 (20% lower natural gas prices and 28% lower electricity prices). With all other factors held constant, we would expect fewer energy efficiency measures to be cost-effective than in the past.
- Compliance software should compare the base case and a proposed design in terms of overall energy cost rather than "source energy". This way, the software results would be consistent with the assumptions used to create the base case and prescriptive requirements. Which energy costing approach to use remains open to debate.

The impacts of the various energy costing regimes on the cost-effectiveness of the Standards were tested by applying the candidate costing methods to hourly energy simulations of six prototype commercial buildings and a residential building prototype for a range of efficiency measures.

This analysis, and the discussions by the project team, helped develop the following insights about the impact of different costing strategies on residential energy-efficiency measures:

- Time-of-use (TOU) and temperature-correlated marginal cost strategies give substantial preference to heating with electric air-source heat pumps over heating with natural gas, to the extent that roof insulation could be dropped to R-19 in most climates.
- The cost savings from higher roof R-value are increased by 50% when propane is the heating fuel rather than natural gas. More ceiling insulation could be required of houses heated with propane.
- The current residential code compliance software treats air conditioner efficiency as constant, regardless of load and outside air temperature. When applied in a cost-effectiveness analysis which uses time-varying rates, a simulation model of air conditioner efficiency that accounts for ambient temperature and load yields markedly different results than a constant efficiency model. .
- Marginal TOU and temperature-correlated electricity costing assigns a lower cost consumption during off-peak and winter periods. Seasonal fuel costing puts a higher cost on consumption during winter periods. Together, this results in a lower energy cost for electric heating than the traditional flat rate valuation.
- Currently, the energy standards discourage electric heating, and so the peak electric loads in California do not occur in the winter. If the standards are altered so that electric heating is allowed more often, this may lead to winter peaking loads in some regions.
- Concerns about devaluing the off-peak periods can be addressed by adjusting the marginal costs up to rates values by applying the fixed costs and profits as a fixed unit cost across all hours. This fix was used by the authors in the "CEC" and "CEC methodology" energy costing strategies

The following conclusions were drawn from the commercial energy and rates analysis:

- Time varying energy costing (temperature correlated or TOU costing) moderately increases the cost savings value of air conditioning efficiency. Unfortunately, the manufacturers of unitary air conditioning equipment were not forthcoming with part load efficiency figures, which would have given greater precision to these results.
- There is a dramatic difference in cooling energy consumption between the different DX equipment part load performance curves available in DOE-2. The ACM Manual currently requires that the reference and proposed building both be modeled with the DOE-2 default curve (which corresponds to suction valve-lift, two compressors). We recommend that the proposed building be modeled with the pre-defined curve that most closely represents the unloading mechanism of the particular DX equipment.
- Time varying energy costing substantially enhances the cost effectiveness of thermal energy storage and gas cooling.
- Time varying energy costing has a small impact on the cost savings from daylighting and low-e windows and has only moderate impact on the increased energy costs from electric resistance heating (when compared to natural gas).
- The impact of time varying costing on the cost savings from lower lighting power density is dependent upon the building type (office and retail occupancies show increased cost savings from time varying costs).
- Improvements in measures that are considered the typical scope of energy standards, such as the efficiency of mechanical systems, the building envelope and lighting systems, are not significantly affected by time varying energy costing.
- Caution should be applied to relaxing standards on envelope requirements in exchange for using technologies which benefit from time varying costing, such as thermal energy storage, which can be more readily replaced or disabled.
- Efficiency requirements for buildings should differ depending upon the heating sources used (electricity, natural gas and propane), because the costs for these sources differ significantly.

Areas for further study, identified during this project, are:

- Develop utility reporting requirements to permit development of geographically-specific marginal costs.
- Test commercial unitary equipment to characterize part load performance as a curve rather than as a single number. This research effort should result in publishing HVAC performance curves for use in any of the software certified as an Alternative Compliance Method.
- Develop an engineering/statistical model of the probability that some areas could have their peak electrical loads in the winter if electric heating requirements were relaxed.

The project team concluded that the temperature correlated approach to developing time-varying costing, with an adjustment to match statewide average total costs, provides a rational basis for developing new efficiency standards (as opposed to the traditional flat rate basis). These new standards would provide better guidance on the design of buildings that reduce peak loads and improve the overall efficiency of the state's energy delivery systems. If the Commission plans on moving forward to reevaluate the cost-effectiveness of the standards under these new costing strategies, then the various stakeholders (builders, environmental groups, energy companies, etc.) need to be informed and their ideas incorporated into the revision process.

2 INTRODUCTION

This is the Final Report on the Dollar Based Performance Standards for Energy Efficiency Project, jointly funded by the California Energy Commission and Pacific Gas & Electric Co. The project is being lead by Douglas Mahone, of the HESCHONG MAHONE GROUP. Team members include Brian Horii, Snuller Price and Jennifer Martin of Energy & Environmental Economics, Charles Eley and Jeff Stein of Eley Associates, and Bruce Wilcox of Berkeley Solar Group.

This project examines the possibility and implications of changing the economic basis used by the California Energy Commission for setting the requirements of the building energy efficiency standards known as the Title 24 Standards. The enabling legislation for the Title 24 requires that the measures specified be cost effective on a life cycle cost basis. The economic analysis procedures used to implement this mandate assumed, in effect, a flat rate cost when determining the economic value of energy savings for each efficiency measure. For purposes of making trade-offs among measures using electricity, natural gas and propane fuels, a source energy multiplier of 3 is applied to the electricity end-use energy. None of these economic assumptions, however, account for the geographic or time variance in energy costs or prices[3]. This project is gathering data to make an assessment of the feasibility and desirability of using economic assumptions that vary the value of energy savings by location, time-of-day or time-of-year.

There are many possible benefits that might be derived from using an area and time dependent economic basis for valuing energy savings in the Title 24 Standards. The resulting Standards would provide new building designers direction to optimize their energy systems to use energy at times when it is less expensive. For example, the revised Standards might 1)encourage the use of off-peak electrical power and reduce the use of on-peak power; or 2) encourage the installation of high EER air conditioning units in areas with severe peak demand problems, while recognizing the energy savings value of high SEER units in areas where peak demand is not a problem. This recognition of area and time differences could provide economic benefits to users in the form of reduced energy bills over the life of the buildings. Reductions in on-peak power usage could also help to retain the reliability of the transmission and distribution system, and could reduce the need for expensive expansions to that system.

A revised set of Title 24 Standards that better optimized buildings' energy usage by time of use would likely favor more appropriate efficiency measures, such as:

- Thermal energy storage - shifts cooling energy to off-peak periods
- Gas air conditioning - gas is not as time dependent as electricity
- Daylighting - turns off electric lighting during peak daytime hours
- Ground source heat pumps - higher efficiency performance during hot weather

The work of this project falls into five general areas:

- Identify future energy cost trends - will allow a better assessment of the wisdom of changing the Standards
- Collect data on average and marginal costs - will provide a better understanding of the time and geography variations

[3] Note that there is a distinction between cost and price. Cost is what it takes to produce and deliver energy. Price is what the customer is charged for the energy. The difference between the two is profit. Prices are influenced by costs, but many other factors enter into the setting of prices, such as market conditions, regulatory constraints, customer preferences, etc.

- Describe possible changes to Title 24 procedures - will enable an assessment of the time and resources that would be required to change the Standards
- Describe time-of-use efficiencies of heat pumps and air conditioners - will provide a technical basis for crediting energy savings for these systems under time-of-use based Standards
- Estimate potential implications of Title 24 changes - will provide a preliminary assessment of the implications of a new basis for the Standards

This Final Report follows three progress reports prepared previously.

3 COST AND PRICE DATA COLLECTION

3.1 Introduction

This chapter was prepared by team member Energy & Environmental Economics (E3). This second Progress Report includes most of the data that has been collected to date, along with discussion of its significance for this project. A separate spreadsheet file contains a more detailed version of the collected data; it is available from the authors.

3.2 Marginal Costs for Electricity (Task A1)

3.2.1 Utility and Supplier Data (Task A1.1a)

Identify present and future sources of utility and supplier cost data available to the public

Cost Item	Source
Generation / Energy Costs	CEC Market Forecasts Historic ISO/PX prices for up to five control areas. Source: www.caiso.com; www.calpx.com
Bulk Transmission Costs	Congestion costs will be embedded in the ISO/PX prices from the market. Marginal cost of expansion may become available through ISO sponsored requests for additional capacity Current Sources: General Rate Case and Performance Based Ratemaking filings with the CPUC. The normal schedule is a GRC every three years and PBR refiled every three to six years. Future Sources: ISO planning documents and published prices.
Local Transmission and Distribution Costs by Area	Expected to be available from General Rate Case Filings. Even though revenue requirements will be set via PBR mechanisms, we expect the CPUC to continue to require GRC filings to determine interclass revenue allocation and rate design. Costs will be available from PG&E on an area-specific basis, but other utilities may only provide system average information. Discussions with the CPUC confirm that utilities would not be required to provide area-specific information unless distributed resource advocates can convince the CPUC that area-specific capacity credits must be offered to distributed devices. DR advocates are currently requesting OII (order instituting and investigation) in this area, but no firm decision to date. Similar information is not required for municipal utilities, and we do not expect this information to be publicly available. Discussions with municipal utilities reveal that City Councils do not typically delve into this level of detail. Moreover, the small staffs are typically pre-occupied with retaining their customer base, and such "research" efforts receive low priority.
Customer Costs	Marginal customer costs will have the same availability as T&D capacity costs discussed above. In addition, the subset of revenue cycle service marginal costs will likely be replaced by the market price to provide these services, as competition for these services increases. These market prices will be found in utility tariff sheets, and in private

Cost Item	Source
	company offerings.
Average Rates	Average costs on a class, or schedule basis can be determined from Utility filings with the CPUC, or from utility Annual reports. Periodically, rate information is also provided to survey organizations and published by organizations such as the Edison Electric Institute (EEI), or in publications such as Public Utilities Fortnightly or Electricity World This information should remain accessible from utilities in the future. Average rates also can be estimated from tariff sheets using prototypical user profiles.
Marginal Rates	Marginal rates can be determined directly from utility tariff sheets. Increasingly, this information is made available through utility web sites. For the IOU's this information will also be available at the CPUC records room, 4th floor San Francisco State Building.

3.2.2 Average Electricity Costs (Task A1.1b)

Identify average electricity costs, and reasons why there would be a difference between average and marginal costs

Utility	PG&E	SCE	SDG&E	SMUD	LADWP	SVP
Information Provided:	Average Costs by Major Fun-ction	Derived from numerous public filings with the CPUC and SEC.	Not available at this time.	Provided by function and class under cover of confidentiality	Not Available	Not Available

Table 1: PG&E Average Costs ($/kWh)

	Generation	Transmission	Distribution and Customer Service	Public Purpose	Total
Revenue at Effective Rates ($000's):	$ 1,995,951	$ 900,959	$ 4,782,447	$ 200,614	$ 7,879,971
Average Cost ($/kWh):	0.0240	0.0108	0.0575	0.0024	0.0948

Data from PG&E 1999 General Rate Case. Exhibit (PG&E-20) Results of Operation Update. Average costs are based on an annual sales forecast of 83,150 GWh. Average costs (historical costs) are not tracked by area, or by customer group by PG&E.

Table 2: SCE Average Costs (1998)

	Generation	Transmission	Distribution	Public Purpose	Nuclear Decom	Total
Forecasted Costs ($k)	$ 5,064	$ 220	$ 1,741	$ 186	$ 109	$ 7,320
Average Cost ($/kWh)	0.0712	0.0031	0.0245	0.0026	0.0015	0.1030

Sources:

Selected Financial and Operating Data: 1993-1997, Edison International 1997 Annual Report, page 56.

Decision 97-08-056, In the Matter of the Application of Southern California Edison Company (U388-E) Proposing the Functional Separation of Cost Components for Energy transmission, and Ancillary Services, Distribution, Public Benefits Programs and Nuclear Decommissioning

Workpaper - Southern California Edison / Application 96-12-019, Exhibit No SCE-1, Appendix B, p. 117

Future Transition Cost Estimates, Application number A96-08-071, Exhibit SCE-14, page 10.

SMUD information provided under cover of confidentiality. X's indicate that data was collected without disclosing the values.

Table 3: SMUD Average Cost - Embedded Cost (1998 $/kWh)

Class	Generation	RS Decommissioning	Transmission	Distribution	Customer	Public Goods	Total
Residential	x	x	x	x	x	x	x
Small Commercial	x	x	x	x	x	x	x
Medium Commercial	x	x	x	x	x	x	x
Large Commercial	x	x	x	x	x	x	x
Agriculture	x	x	x	x	x	x	x
Total	x	x	x	x	x	x	x

The IOU's in California allocate revenues and design rates based on marginal costs. We do not expect utilities to have detailed average cost studies, other than system-level embedded cost studies produced for FERC. While we can see basing the standards on average customer bills for a "billpayer" perspective, or on marginal costs for a "utility" perspective, we do not believe that average costs are appropriate for policy decisions. Average costs would only be useful to the extent that they provide insight into future customer bill levels.

Reasons for the difference between average and marginal cost:

An "Average Cost" is the cost of production divided by output. The cost used can refer to variable costs, fixed costs, or both. If TVC is total variable cost to produce output Q, and TFC is the total fixed cost to produce output Q, then average total cost equals:

(1) $(TVC + TFC) / Q$

Under traditional cost of service ratemaking, average total cost is roughly equivalent to the average rate that a utility's customers would pay.

Marginal cost is the change in cost associated with a change in output. If ΔTVC is the change in total variable cost resulting from a change in output of ΔQ and if ΔTFC is the change in total fixed costs resulting from a change in output of ΔQ, marginal cost equals

(2) $(\Delta TVC + \Delta TFC) / \Delta Q$

But since ΔTFC is zero (fixed costs being fixed[4]), marginal cost equals

(3) $\Delta TVC / \Delta Q$. [5,6]

[4] The determination of which costs are fixed versus variable depends on the timeframe of the analysis. The longer the perspective taken, the more costs can be considered variable. For example, for a fossil plant, the short run variable costs would only consist of fuel and some impact on operations and maintenance (ignoring taxes and municipal levies etc). If one were looking at the impact of a sustained multi-year change in operations, however, then staff levels could be altered, and some capital related additions or modifications to physical plant would also become variable. Lastly, under the long-run perspective, all capital plant costs could be considered variable.

[5] Mansfield, Micro-Economics Theory and Applications Fifth Edition, pp. 202-203

Comparing Equations 1 and 2 indicates that one should not expect that average and marginal costs would be equal. The most notable differences are the lack of a term for fixed costs in the marginal cost calculation, and the fact that marginal costs look at changes in costs, rather than total costs.

More importantly, marginal costs look only at future costs that change due to some causal factor such as load growth, kWh usage, or numbers of customers. Average costs, on the other hand include all costs, and include past sunk investments.

3.2.3 Electric Marginal Cost (Task A1.1c)

Obtain marginal cost data for California's investor-owned utilities and municipal utilities for transmission, distribution, customer-related new construction, and customer service.

Utility	PG&E	SCE	SDG&E	SMUD	LADWP	SVP
Information Provided:	Capacity Costs for Transmission, Distribution, and Secondary. Costs provided by area.	Costs obtained from public ratemaking filings.	No Response	Provided by function and class under cover of confidentiality	LADWP does not calculate. Supporting information is not publicly available.	SVP does not calculate. Supporting information is not publicly available.

Table 4,

Table 5, and Table 6 show the PG&E transmission, primary distribution, and secondary distribution costs respectively in $/kW-year for each division. These costs are calculated based on the planned expansion activities at PG&E at the time of the filing of these costs in their 1996 rate case.

The marginal capacity costs represent the cost savings that could be achieved from deferring the traditional T&D investments through load reduction in each of the areas. The cost savings arises because of the difference between the inflation rate of the equipment and the cost of funds required to finance the projects. In grossly simplified terms, each year you can delay construction saves you roughly 5-8% of the capital project cost (ignoring changes in expected unserved energy and customer value of service)

Projects refer to PG&E's large identified transmission planning projects from their capital expansion plans. The Annuals are the transmission costs that PG&E has historically incurred, and expects to continue to incur in the area, in addition to the projects identified above.

Table 5, the distribution marginal costs are shown for projects and annuals. For the distribution system, all expenditures over $1 million require identification and approval. These identified expenditures are referred to as the "project" costs. Expenditures that fall under that $1 million threshold, but are still expected to be incurred for the areas are referred to as the "annual" costs.

The annuals category includes the cost of new business such as hook-ups and other costs that will not vary significantly with a change in building standards, i.e. changing the building standards

[6] Marginal costs are traditionally calculated as the cost change associated with a very small output change (or even calculated using derivative functions and infinitesimal changes). Since the derivative of most cost functions is not a constant, any marginal cost estimate would only be valid over a limited range of change from the base case output level. Moreover costs that may be fixed over a small change in load, may become variable over a much larger change. The classic example is the marginal cost to transport passengers on a train. The marginal cost of an additional customer is practically nothing, until the new customers require you to purchase another passenger compartment.

does not impact these costs. Therefore, in calculating the impact of the standards from the utility perspective it is appropriate to use the final column 'Total Less New Business' which represents costs that could be avoided through changes in customer usage.

Table 4: PG&E Transmission Marginal Capacity Costs by Division $/kW-year

	Projects	Annuals	Total
East Bay	$ 5.08	$ 1.74	$ 6.82
Golden Gate	$ 9.40	$ 1.09	$ 10.48
North Bay	$ 4.44	$ 0.35	$ 4.79
Sacramento	$ 3.88	$ 0.31	$ 4.18
San Jose	$ 8.60	$ 2.01	$ 10.61
De Sabla	$ -	$ 0.60	$ 0.60
Colgate	$ -	$ 1.10	$ 1.10
Shasta	$ -	$ 6.43	$ 6.43
Drum	$ 8.59	$ 2.94	$ 11.53
Stockton	$ 3.37	$ 1.56	$ 4.93
Coast Valleys	$ 19.16	$ 1.26	$ 20.42
Humboldt	$ -	$ 0.03	$ 0.03
San Joaquin	$ 7.96	$ 6.82	$ 14.78

Table 5: PG&E Primary Distribution Capacity Costs by Division

	Projects	Annuals	Total	New Business Dist	Total Less New Business
East Bay	$ 13.36	$ 40.95	$ 54.31	$ 32.19	$ 22.12
Golden Gate	$ 9.49	$ 68.08	$ 77.57	$ 43.85	$ 33.72
North Bay	$ 8.52	$ 59.02	$ 67.54	$ 43.72	$ 23.82
Sacramento	$ 8.47	$ 36.30	$ 44.77	$ 28.68	$ 16.09
San Jose	$ 16.45	$ 48.55	$ 65.01	$ 34.73	$ 30.28
De Sabla	$ 12.85	$ 62.40	$ 75.25	$ 50.15	$ 25.10
Colgate	$ 13.39	$ 62.40	$ 75.79	$ 50.15	$ 25.64
Shasta	$ 5.07	$ 62.40	$ 67.47	$ 50.15	$ 17.32
Drum	$ 13.23	$ 58.02	$ 71.25	$ 46.69	$ 24.56
Stockton	$ 16.79	$ 63.82	$ 80.60	$ 47.91	$ 32.70
Coast Valleys	$ 6.65	$ 79.77	$ 86.42	$ 51.95	$ 34.47
Humboldt	$ -	$ 132.06	$ 132.06	$ 103.80	$ 28.26
San Joaquin	$ 9.19	$ 48.03	$ 57.22	$ 37.49	$ 19.72

Note: Annuals include New Business Distribution Marginal Costs

PG&E's secondary costs represent the load-growth related cost of capacity for secondary line drops and final line drops. The costs consist primarily of the cost to change-out equipment due to "creeping" load growth for customers.

Table 6: PG&E Secondary Distribution Capacity Costs by Division

	Total Costs
East Bay	$ 0.61
Golden Gate	$ 1.42
North Bay	$ 1.34
Sacramento	$ 0.41
San Jose	$ 1.00
De Sabla	$ 1.53
Colgate	$ 1.53
Shasta	$ 1.53
Drum	$ 0.84
Stockton	$ 1.03
Coast Valleys	$ 1.92
Humboldt	$ 2.12
San Joaquin	$ 1.13

Table 7: SCE Marginal Capacity Costs

Capacity Costs ($/kW-yr)	Transmission	Distribution
Coincident	39.91	14.28
NonCoincident	4.43	30.35

Source: SCE Unbundling Application workpapers, Appendix B, p. 27

The coincident costs are incurred due to customer demand at the time of the facility peak utilization. The Noncoincident costs are incurred based on customer peak demands, regardless of when that peak demand occurs. The costs are additive.

Notice that the transmission costs are far more coincident than the distribution costs. This difference reflects that fact that the transmission system is sized largely to meet customer demands at the time of the system peak --- the coincident peak. Distribution facilities, however, being much closer to the customer, are sized more for the individual peak of the customers (noncoincident) in the area, rather than the system coincident peak.

Table 8: SCE Customer Marginal Costs

Marginal Customer Cost	Average $/Cust-Yr	O&M $/Cust-yr	New Customer Hookup Cost ($/Hookup)
Domestic	43.4	21.29	670.01
GS-1	102.32	49.2	1696.68
GS-2	576.74	82.24	15797.45

Source: SCE Unbundling Application workpapers, Appendix B, p. 14.

The average customer costs are a blend of the O&M customer costs and a portion of the new customer hookup costs. The portion of new customer hookups added to the average cost is equal to the ratio of the number of new incremental hookups to the total number of customers in the class.

3.2.4 Generation/Energy Costs (Task A1.1d)

Obtain market clearing forecast report from the Commission and collect data from other potential sources of information for future marginal generation/energy costs

Historically, marginal generation costs were available from PG&E, SCE, and SDG&E in the form of the operating cost of their plants on the margin, or purchases on the margin at any hour of the year (often referred to as system lamdas). California IOUs no longer calculate generation marginal costs for public ratemaking purposes. In place of marginal costs, market prices will be set in the near term by the California PX, and in the longer term, by any number of scheduling coordinators. There are currently a few alternatives to the PX (like the APX) for non-IOU participants. Once the Competitive Transition Charge goes away in 2002 (or prior), the IOUs will no longer be required to purchase all of their power from the PX. If the IOU purchases leave the PX, there is no guarantee that there will be a dominant scheduling coordinator that will reveal market prices for the entire state. The ISO will continue to set zonal transmission charges, and resolve ancillary service payments, and may provide historical market price information through its market surveillance function. At the current time, however, there is no reliable futures market upon which long-term market price forecasts may be based. Baring the development of such a market, the CEC's forecasting group or private consulting firms may provide the only source of this information in the future.

3.2.5 Future Rate Changes (Task A1.2)

Obtain information for investor-owned and municipal utilities regarding how transmission, distribution, customer-related new construction, and customer service is expected to change in future years after 2002. Develop a method of forecasting these costs over a 30-year time horizon.

T&D: We expect overall T&D costs to decline (relative to inflation) in the near term as utilities maximize the efficiencies of the current systems for the benefit of shareholders and customers under PBR regulation. Distributed resources (DR) may add competition to the T&D system, but PBR will provide pressures to reduce T&D costs anyway. In fact, DR may provide a cost-cutting option for utilities faced with expensive T&D upgrades. As systems age and load growth continues to stress the system, however, we expect costs to rise at or above inflation as the system is expanded and rebuilt. Also, for PG&E we expect an upward blip in T&D prices in the near term as delayed construction and maintenance is performed on the system (an increase of 5 to 10% on the T&D portion of the rate is likely in 1999)

T&D rates will continue along the trajectories established in the PBR proceedings for SCE, SDG&E, and PG&E (expected to be filed within the coming year) in the near term. The PBR proceedings will probably be revisited every four to six years, at which point the trajectories may be altered to reflect changes in utility costs.

SDG&E is currently litigating a new PBR mechanism. The new PBR may be either a rate or revenue cap, and have a (CPI-X) productivity factor between 0.68% and 2.3% (The current range of party positions). CPUC staff (office of ratepayer advocates) project that rates for SDG&E will escalate at an average of 1.7% till 2002.

SEC's current PBR mechanism yields CPI-X escalation factors of 1.83% in 1997, and 1.4% in 1998.

Beyond that basic information, it is not possible to derive a reasonable forecast of T&D rates until the PBR proceedings have been completed for each utility. In the interim, a ballpark number of 5% increase for PG&E in 1999, followed by 1.7% annual increases for all utilities could be used.

Customer-related construction. Utilities have traditionally either absorbed much of these new customer costs, or passed them along to the entire utility customer base. For customers requiring extensive construction, utilities would require customers to pay for costs that exceed some contribution threshold. The contribution threshold would typically be based on prescriptive rules on "free footage" or on some multiple of the annual revenue or margin expected from the customer. The new customers were subsidized by the entire customer base in order to increase asset utilization and exploit economies of scale in generation.

With the unbundling of electric service, however, we see a much less compelling argument for the continuation of generous free allowances. As competitive pressures increase upon the T&D system, we believe that utilities may not want to subsidize new customers with higher charges to existing customers. Moreover, collecting new construction costs from developers up front reduces the collection risk that utilities would otherwise face if T&D were to become competitive. We therefore expect the charges paid by developers to increase, even as the total cost of the customer-related construction may decline because of PBR and efficiency gains. With the increased cost efficiencies and the shifting of costs onto the developers, we also expect overall utility bills to decrease as the subsidization of new construction is reduced.

Several intervenor groups are actively pushing the above perspective before the CPUC

Customer Service: We forecast that customer service costs will decline over time, as competition, advancements in telemetering, and automation in information and telecommunication systems drive costs and prices down.

We expect most of these cost savings to be captured by utility shareholders as part of the PBR process. The recent proposed decision on this topic from the CPUC also indicates that customers selecting third party providers of customer service might not realize significant cost savings because of the way that charges will be credited back to customers. In short, customers are charged the current full cost of these activities by utilities, but are refunded back only the marginal cost savings of avoiding these services if they select a third party provider. Since the current full cost of providing these services is significantly larger than the marginal cost of providing the service, there is little opportunity for customers to save money by selecting a third party. Thus, the real savings for customers would come from retooling of the existing utility processes (or a change in the regulations).

3.3 Forecasting Long-Term Electricity Rates (Task A.2)

There are several methods to forecast long term electricity rates at the end-use level over a forecast horizon of 30 years. These are total rates paid by electricity consumers for their consumption. Each rate contains the price for electricity energy and the charges for services required for delivering that energy to a consumer's premise. These services include transmission, distribution, and customer services (e.g., billing, metering, connection, etc.).

As will be shown below, the long forecast horizon coupled with changing regulatory and market environment renders some of the methods impractical. Nonetheless, it is possible to model market competition for electricity energy and ratemaking process for other services using simplifying assumptions. These assumptions are admittedly restrictive but are necessary to make a long-term forecast in a changing market environment. The validity of the forecast then of course hinges on how well these assumptions reflect the future regulatory and market realities. As a result, the discussion of such models represents an initial effort to tackle the difficult task of forecasting long-term rates. In what follows, we discuss the available methods and conclude with our recommendation.

3.3.1 Market price data

For certain commodities, there are long-term forward prices available. For example, natural gas has long-term forward contracts with well-defined price terms. To the extent that the market for these contracts is active, efficient (i.e., all traders have identical access to the market information), and complete (i.e., there are contracts with various lengths and contingencies), the forward contract prices are the reliable predictor of long-term gas price. Unfortunately, no such data are available for electricity energy, especially with a forecast horizon of 30 years. More importantly, the final prices paid by consumers at the end-use level comprise of the energy price, rates for transmission and distribution (T&D), and other services. Therefore this method would, at best, provide only a small portion of the total cost of delivered energy.

3.3.2 Statistical forecast

Statistical estimation is a common tool to develop a forecast model. There are two types of models: structural and time series.

Structural model

A structural model is a regression that relates the electricity rate at the end-use level with its drivers such as customer base, demand, fuel prices, and weather. Such a model would work well if (a) the structural relationship underlying the regression is stable, and (b) there are sufficient data to reliably estimate the regression. Both (a) and (b) do not reflect that the California electricity industry has undergone a significant structural change.

The era of an integrated utility providing bundled services at embedded cost rates has been replaced in 1998 by retail access under which all end-users can choose their preferred suppliers. Moreover, the total rate is unbundled, with spot electricity energy competitively priced at market. There are electricity futures and forward contracts, but they only apply to relatively short time horizon with physical delivery occurring in the next few years. This affirms our initial finding that there are no market price data that can accurately value electricity energy over a 30-year time horizon.

The unbundled rates for the remaining services are largely based on the embedded costs of a local distribution company (LDC) emerged from the once integrated utility that has now divested most of its generation assets. The ratemaking process for these services are expected to change due to regulatory preference for incentive ratemaking (e.g., price cap regulation) over the traditional approach of rate of return ratemaking. Consequently, a regression model of total rates estimated using data up to 1997 is no longer valid for the purpose of long-term forecasting. Updating the model is difficult because of the lack of data that can adequately describe the structure of end-user rates under retail access.

Time series model

A time series model relates the electricity rate at the end-use level with its past values, while accounting for trend, seasonal and cyclical fluctuations. Such a model would work well if (a) the time pattern is stable, and (b) there are sufficient data to reliably estimating the regression. Both (a) and (b) are untrue in California because in 1998 retail access has become a reality. As a result, the time series approach is inapplicable to forecasting long-term electricity rates at the end-use level.

3.3.3 Disaggregate Forecast

This approach projects long-term electricity rates at the end-use level by projecting (a) the long-term market prices for electricity energy; and (b) the embedded cost rates for T&D and other services. The approach is not statistical but relies on a representation of competitive market interactions and the financial consequences of regulatory ratemaking. We discuss (a) and (b) in turn below.

Market price of electricity energy

Stacking Model

An approach to forecast the long-term market price is the stacking model. The model determines the market clearing price (MCP) using the least-cost dispatch of plants to serve the hourly demands, subject to transmission transfer limits. It assumes that each generator makes a bid into a power exchange for its entire output. When hourly load equals hourly supply, the MCP is the bid of the last generator dispatched. The model is simple, ignoring random and transitory fluctuations in demand and available capacity. An elaborate version of the stacking model would account for hourly stochastic events that affect the dispatch of plants. The value of an elaborate model is obvious in the context of short-term forecast in the next few months. However, it remains unknown for a forecast that applies to the next 30 years.

For empirical implementation, the following assumptions are typically made in development of a stacking model:

- Because of plant outages and hourly demand fluctuations, the hourly demand is adjusted upwards (e.g. 10%) to account for an operating reserve.
- Hourly demand is relatively price insensitive so that MCP is determined by the projected levels supply and demand, without accounting for demand responses to price changes.
- Bilateral contracts do not affect the dispatch order as each contract reflects "reasonable" matching of load and generation (e.g., baseload units serving baseload demand).
- Competition is fierce and sellers make bids based on their respective short-run marginal cost (SRMC).
- Easy market entry at "all-in" cost caps the maximum annual MCP. For example, the all-in cost of a combined cycle gas turbine is the sum of (a) per kWh cost of new capacity (= $/kW installed * annual carrying charge / annual capacity factor); and (b) per kWh variable cost (= heat rate * gas price + per kWh O&M).
- All dispatched generators receive the MCP, even if some bids are below the MCP.

These assumptions preclude the model to be a daily operation model for real time dispatch or trading. However, the model provides plausible projection of long term prices used in stranded cost estimation. An optimization model that accounts for random fluctuations in demand and supply does not necessarily yield more accurate results because of the uncertainties in input data assumptions. To wit, the assumptions on long-term demand growth and new plant construction can affect the long-term market price forecast more than the infrequent unplanned outages of some baseload plants.

The model is often subject to the following criticisms, even though none of them is serious. These criticisms prohibit this type of model from reasonable forecasts of market prices in the near term. But the long-term nature of the forecast renders these criticisms immaterial. We discuss each criticism below.

First, the model does not embody strategic bidding behavior of market participants. However, persistently high prices invite market entry and regulatory actions. As a result, strategic bidding should not have a permanent effect on the long-term price forecast.

Second, the assumption of demand price insensitivity implies that the model does not consider buy bids submitted by buyers into the California Power Exchange. This can potentially cause an upward bias in the forecast because if demand would decline in response to price increases, it should lower the MCP. This bias, however, should be small because the long-run supply is infinite at the "all-in" cost of a new generation unit and demand price sensitivity has no effect on the long-term MCP.

Finally, it may be unrealistic to assume easy market entry so that new plants can always meet the demand in excess of available generation. This assumption biases the MCP downwards. However, as long as market entry can occur within a reasonable time frame (e.g., 2-3 years), its effect on a 30-year forecast is immaterial.

Production Simulation Models

The other option for forecasting market prices is to use a detailed production simulation models. Industry standard models include Elfin, PROMOD, PMDAM, Aegeas, and PROSYM. These models can rely upon load duration curves, or chronological data. They all share the advantages of being able to model operating constraints in the simulated dispatch of plants through one or more interconnection generation regions.

The models are well received in terms of their methodological abilities, but do require very skilled operators. In addition, the process of benchmarking or calibrating these models can be quite time consuming and complex, given the myriad inputs and details that these models can incorporate.

Moreover, once the modeler has to start making assumptions regarding the location and type of new generation entering the market, the accuracy of any model begins to become suspect. (Not to mention the accuracy of load growth forecasts more than a few years out in the future.)

The CEC's current forecasts are based on production simulation runs.

Rates for T&D and other services

The rates for these services depend on the form of rate regulation: rate of return vs. performance based. Rate of return regulation results in embedded cost rates, while performance based regulation (PBR) sets rates based on price or revenue cap rules with less frequent rate cases. Our discussion will only focus on price caps because price cap regulation can more directly control rates than revenue cap regulation.

Embedded cost ratemaking

The embedded cost for a particular service includes O&M expense, taxes, and return on approved investments already in the rate base. The embedded cost rate is the result of dividing the embedded cost by the projected sale of that service. For example, the revenue requirement for distribution divided by the kWh distributed results in a per kWh charge for distribution.

There are two methods to project the embedded cost rate. The first method entails estimating a regression that relates the embedded cost rate with drivers such as time trend demand and customer base. This approach assumes that the past rate changes track inflation, demand and customer growth. The resulting forecast can be reasonably accurate if the assumptions on the rate drivers (e.g., O&M costs and the allowed rate of return) and future investments follow the historic pattern. But if the data assumptions and future investments will deviate significantly from the historic trend, the regression approach may no longer be applicable.

The second approach is a financial model of the LDC's operation. Such a model can accommodate changes of the ratemaking assumptions and track how future investment may enter the rate base. To implement the model, however, requires data on the LDC's investment expenditures. These expenditures may be projected using a regression model that relates annual investment to demand growth. Alternatively, the expenditures may be the result of integrated resource planning that identifies the least-cost solutions to meet demand growth while maintaining service reliability.

PBR ratemaking

Performance based ratemaking regulation will likely replace the traditional allowed rate of return regulation. PBR specifies the price cap (C) that a LDC can charge. The common formula is that the cap for the next year is the cap of the current year, adjusted by the difference between the growth of a price (or cost) index (e.g., CPI) and productivity gain (X). The cap may further be adjusted by Z factors that include incentives for exceeding the targets for service quality and reliability. Thus, $C_{t+1} = C_t (1 + CPI – X) + Z_t$. Assuming that the LDC will maintain service quality and reliability to meet the targets, forecasting future embedded cost rate entails adjusting the current rate level using a long-term projection of inflation and productivity.

3.3.4 Recommendation

The major findings from our discussion of the methods are as follows:

- Statistical approaches that forecast long-term rates at the end-use level are impractical because of the significant structural changes.
- Disaggregate estimation is a promising approach. It entails estimation of the long-term market prices for generation under a set of simplifying assumptions. It also requires the modeling of embedded cost ratemaking or price cap regulation.

These findings lead to our recommendation of the disaggregate approach for forecasting the long-term electricity rates at the end-use level.

3.3.5 Marginal Cost by Time and Area (Task A1-3a)

Compile total marginal cost data on an hourly basis or other appropriate time of use basis, and by geographic area for generation, transmission, and distribution.

This section summarizes the electrical marginal cost data that has been collected for generation, transmission, and distribution. The data includes market price forecasts of electricity done by the CEC, as well as transmission and distribution marginal cost from PG&E, SCE, and from regulatory filings from the PUC.

Table 9 and Table 10, below, summarize the average generation market clearing price by TOU period for Northern and Southern California. This data has been calculated as the simple average across the TOU period from the CEC market price forecast study[7].

There are a number of ways to compute averages of hourly market prices. For the standards process, we want to capture the expected cost of energy saved through a more efficient end-use. The ideal method to calculate this would be a weighted-average of market prices based on a particular efficiency measure's energy savings. Since this would require a different allocation for each efficiency measure it is not practical in the standards making process. Another approach is

[7] Data from Interim Staff Market Clearing Price Forecast for the California Energy Market Study, December 10, 1997 by Joel Klein. Electricity Analysis Office, CEC.

to summarize market clearing prices using a load-weighted average based on customer class profiles. However, this assumes that (1) energy savings for a customer will be in proportion to the customer's load and (2) we can forecast the customer's load shape. Class shapes are available from utilities, but the number of them may make it difficult to implement in a practical standards process. The several dozen load shapes would make for several dozen estimates of market price. In addition, the assumption (1) limits the usefulness of load-weighted average based on class shape for a number of efficiency measures. Therefore, we have used a simple average to compute the market prices by TOU period.

Table 9: Southern California Generation Market Clearing Price Forecast by TOU Period

	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak
1998	34.00	30.74	23.10	31.79	24.35
1999	31.50	28.78	22.95	30.68	24.65
2000	34.47	30.42	23.74	32.27	25.59
2001	34.16	30.31	24.04	33.19	26.21
2002	38.72	32.89	25.69	36.17	28.07

Time of use period definitions:
Summer begins at 12:00 am on the first Sunday in June and continues until 12:00am of the first Sunday in October.
On-Peak: Noon to 6:00pm summer weekdays except holidays
Partial-Peak: 8:00am to Noon and 6:00 pm to 11:00 pm summer weekdays except holidays
8:00am to 9:00pm winter weekdays except holidays
Off-Peak: All other hours

Table 10: Northern California Generation Market Clearing Price Forecast by TOU Period

	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak
1998	38.37	31.25	24.55	30.06	25.56
1999	34.85	28.35	23.51	28.06	24.93
2000	39.90	30.44	23.90	28.25	25.29
2001	41.50	31.17	24.95	29.31	26.42
2002	49.28	33.31	25.91	30.84	27.76

In developing area- and time-specific marginal costs for transmission and distribution, PG&E develops weights called 'Peak Capacity Allocation Factors' (PCAFs) they use to allocate transmission and distribution marginal costs to different times of the year. In summer-peaking areas such as the PG&E Sacramento Division, the PCAFs allocate capacity costs to the summer period, and in winter peaking areas such as the Yosemite Division they allocate costs to the winter season. Table 11, below, shows the PCAFs for each PG&E Division by TOU period. For example, for the Diablo Division, in Contra Costa County, 55.7% of the transmission and distribution costs are allocated to the on-peak summer period.

Table 11: PG&E Peak Capacity Allocation Factors (PCAFs) by Division

	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak
Central Coast	20.4%	16.7%	3.0%	25.3%	34.6%
De Anza	38.7%	8.1%	0.0%	3.3%	49.8%
Diablo	55.7%	16.6%	2.7%	10.9%	14.1%
East Bay	7.2%	5.9%	2.2%	28.6%	56.1%
Fresno	47.0%	19.3%	0.5%	1.9%	31.3%
Kern	60.5%	25.5%	0.8%	1.4%	11.8%
Los Padres	14.4%	11.8%	1.8%	14.3%	57.7%
Mission	48.4%	11.0%	1.1%	27.6%	11.8%
North Bay	17.1%	5.6%	7.9%	44.2%	25.2%
North Coast	17.4%	6.7%	11.8%	34.9%	29.1%
North Valley	40.1%	20.8%	2.1%	4.0%	33.0%
Peninsula	20.9%	4.3%	3.3%	36.2%	35.3%
Sacramento	48.0%	15.5%	1.0%	1.6%	33.9%
San Francisco	17.5%	7.6%	2.3%	32.9%	39.7%
San Jose	43.5%	12.9%	4.4%	22.2%	17.1%
Sierra	25.3%	10.3%	8.4%	8.5%	47.5%
Stockton	43.7%	13.2%	2.7%	2.9%	37.6%
Yosemite	5.6%	3.2%	0.4%	0.5%	90.2%

PG&E TOU Periods are:
Summer: May through October
  Peak Noon to 6pm. Monday to Friday, Excluding Holidays
  Partial Peak: 8:30am to Noon, 6pm to 9:30pm. Monday to Friday, Excluding Holidays
  Off: All other hours
Winter: November through April
  Partial Peak: 8:30am to 9:30pm. Monday to Friday, Excluding Holidays
  Off: All other hours

Table 12, below, shows the PG&E T&D costs by TOU period. These costs are calculated by allocating the transmission and distribution marginal costs using the PCAF weights and then dividing by the number of hours in each TOU period as shown in the following equation.

T&D Marginal Cost$_{tou}$ (\$/kWh) = T&D Marginal Cost (\$/kW-yr) * PCAF$_{tou}$ / Number of Hours$_{tou}$

Table 12: PG&E Transmission and Distribution Costs by TOU Period ($/kWh)

	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak
Central Coast	$ 0.0179	$ 0.0126	$ 0.0007	$ 0.0076	$ 0.0062
De Anza	$ 0.0250	$ 0.0045	$ -	$ 0.0007	$ 0.0065
Diablo	$ 0.0254	$ 0.0065	$ 0.0004	$ 0.0017	$ 0.0013
East Bay	$ 0.0033	$ 0.0023	$ 0.0003	$ 0.0045	$ 0.0052
Fresno	$ 0.0259	$ 0.0091	$ 0.0001	$ 0.0004	$ 0.0035
Kern	$ 0.0333	$ 0.0120	$ 0.0001	$ 0.0003	$ 0.0013
Los Padres	$ 0.0126	$ 0.0088	$ 0.0005	$ 0.0043	$ 0.0103
Mission	$ 0.0313	$ 0.0061	$ 0.0002	$ 0.0062	$ 0.0016
North Bay	$ 0.0079	$ 0.0022	$ 0.0010	$ 0.0070	$ 0.0024
North Coast	$ 0.0082	$ 0.0027	$ 0.0016	$ 0.0056	$ 0.0028
N. North Valley	$ 0.0168	$ 0.0075	$ 0.0002	$ 0.0006	$ 0.0028
S. North Valley	$ 0.0156	$ 0.0070	$ 0.0002	$ 0.0005	$ 0.0026

Peninsula	$ 0.0147	$ 0.0026	$ 0.0007	$ 0.0088	$ 0.0051
Sacramento	$ 0.0153	$ 0.0042	$ 0.0001	$ 0.0002	$ 0.0022
San Francisco	$ 0.0123	$ 0.0046	$ 0.0005	$ 0.0080	$ 0.0057
San Jose	$ 0.0281	$ 0.0071	$ 0.0008	$ 0.0049	$ 0.0023
Sierra	$ 0.0144	$ 0.0050	$ 0.0014	$ 0.0017	$ 0.0055
Stockton	$ 0.0261	$ 0.0067	$ 0.0004	$ 0.0006	$ 0.0046
Yosemite	$ 0.0031	$ 0.0015	$ 0.0001	$ 0.0001	$ 0.0101

Table 13: SCE Marginal Costs by TOU Period (1998 $/kW-yr)

Costs by TOU Period	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak
Transmission					
Coincident ($/kW-yr)	33.30	2.83	-	3.78	-
Noncoincident ($/kW-yr)	0.33	0.38	1.16	0.95	1.61
Distribution					
Coincident ($/kW-yr)	11.91	1.01	-	1.35	-
Noncoincident ($/kW-yr)	2.25	2.62	7.94	6.51	11.03

SCE TOU Periods are:

Summer: 12am on the first Sunday in June till 12:00am of the first Sunday in October

On- Peak: Noon to 6:00pm. Summer weekdays excluding holidays

Mid-Peak: 8:00am to Noon and 6:00pm to 11:00pm Summer weekdays excluding holidays

8:00am to 9:00pm Winter weekdays excluding holidays

Off-peak All other hours

Table 14: SCE Marginal Costs by TOU Period (1998 $/kWh)

Note that the transmission and distribution marginal costs from above have been re-expressed on a $/kWh basis here.

Costs by TOU Period	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak
Transmission					
Coincident ($/kWh)	0.0514	0.0037	-	0.0020	-
Noncoincident ($/kWh)	0.0005	0.0005	0.0005	0.0005	0.0005
Distribution	-	-	-	-	-
Coincident ($/kWh)	0.0184	0.0013	-	0.0007	-
Noncoincident ($/kWh)	0.0035	0.0035	0.0035	0.0035	0.0035
Customer					
Domestic					
Average ($/kWh)	0.0670	0.0574	0.0189	0.0231	0.0136
O&M ($/kWh)	0.0329	0.0282	0.0093	0.0113	0.0067
New Hookup ($/kWh)	1.0340	0.8863	0.2923	0.3566	0.2104
GS-1					
Average ($/kWh)	0.1579	0.1353	0.0446	0.0545	0.0321

O&M ($/kWh)	0.0759	0.0651	0.0215	0.0262	0.0154
New Hookup ($/kWh)	2.6183	2.2443	0.7403	0.9030	0.5327
GS-2					
Average ($/kWh)	0.8900	0.7629	0.2516	0.3069	0.1811
O&M ($/kWh)	0.1269	0.1088	0.0359	0.0438	0.0258
New Hookup ($/kWh)	24.3788	20.8961	6.8924	8.4074	4.9600

Information was not provided directly by SCE, nor was geographic information available. The above table was derived from information filed with the CPUC as part of Edison's unbundled ratemaking proceeding. (Workpapers in Support of A.96-12-019, Exhibit SCE-1 – Prepared Testimony, Chapter IV and Appendix B) This information will be available in future General Rate Case Proceedings before the CPUC. The CEC should become an active participant in these cases to guarantee receipt of the detailed workpapers in the future. Unlike testimony, the supporting workpapers are not kept by the CPUC official files room, and there is no guarantee of utilities being able to produce (or being willing to produce) copies of the workpapers once the proceeding is closed.

The original source of the information can be found in SCE's 1992 General Rate case (see D. 92-06-020). The SCE workpapers express marginal capacity costs in terms of coincident-related costs and non-coincident-related costs. For development of the time differentiated marginal costs, we have assigned the coincident costs periods based on SCE's Coincidence conversion factors, and have spread the noncoincident costs (including marginal customer costs) uniformly to all hours of the year. The conversion factors are similar to PG&E's PCAF allocation factors.

The transmission and distribution marginal costs by time were estimated using the load shape for the SDG&E system and the T&D marginal cost from the CBEE cost-effectiveness input value study of $14.00/kW for the year 2002.

Table 15: SDG&E Allocation of T&D Marginal Costs

	Peak	Semi-Peak	Off-Peak
Winter	0.0%	0.0%	0.0%
Summer	94.6%	5.4%	0.0%

Table 16: San Diego Gas and Electric Avoided T&D Capacity Costs ($/kWh) ($2002)

	Peak	Semi-Peak	Off-Peak
Winter	$ 0.00	$ 0.00	$ 0.00
Summer	$ 0.013	$ 0.001	$ 0.00

3.3.6 Impact of Usage on T&D Costs. (Task A1-3b)

Review marginal cost data to determine how changes in energy use affect energy costs and transmission and distribution utilization and expansion costs.

Energy costs projections show a higher cost in the summer on-peak (summer afternoon) than any other portion of the year. This is consistent with the marginal costs that utilities in California have traditionally shown. These cost differentials are also consistent with the limited open market experience in California to date. Ultimately, however, the time pattern of energy costs will depend highly on transmission and generation additions in and near the state. IOU's in California have maintained relatively high reserve margins, or enjoyed regional surplus capacity conditions in recent memory. It is unclear what will happen to summer rates in the future as the current surplus capacity in the state dwindles away under the pressure of increased electricity usage in the state. In the past months the State and the nation has seen spikes of market prices in excess of 2500 and 7,000 $/MWh. To the extent this is market inefficiency to be smoothed out, versus signs of open market realities cannot be determined at this time.

Examination of the PG&E and SCE T&D marginal cost information shows that the transmission costs are caused predominantly by usage in the summer peak period. This conclusion is based on the PG&E peak allocation capacity factors (PCAFs) and the SCE conversion factors. As expected, however, as we examine equipment that is closer to customer meter, the costs are caused less by the customer load coincident with the system peaks, but more by the individual peak (and peak timing) of the single customer. This importance of the customer noncoincident peak is illustrated by the much higher percentage of distribution costs that are allocated to noncoincident demand than coincident demand for SCE.

This does not mean, however, that distribution costs are not affected by customer usage during the summer peak period. Studies performed by PG&E in the early 1990's on the coincidence of peaks on feeders and substations suggest that customers in summer air conditioning areas will experience their highest usage at the same times of the year (during heat storms). As a result, for those customers, noncoincident and coincident demand are essentially the same, and any reduction of summer air conditioning load could reduce loading on both the transmission and distribution systems during their respective peaks.

We would expect that a consistent, systematic reduction in coincident peak load could allow utilities to revise their planning guidelines for new construction, and possibly allow utilities to serve customers at the same level or safety and reliability at a lower total cost.

3.3.7 Peak Capacity Allocation Factor and Temperature

Introduction

The derivation of hourly capacity costs C_h involves allocating the annualized cost C ($/kW-year) into hourly values ($/kWh). Specifically,

$$[1] \quad C_h = C\, W_h$$

where W_h = peak capacity allocation factor (PCAF) = $D_h / \Sigma_h D_h$; and D_h = incremental demand above the threshold for peak hour h.[8] These peak hours are the hours with the highest loads. The threshold is the minimum load level among the peak hours. The choice of peak hours can be the top 100 hours or the hours with loads that are one standard deviation above the average load for the 8,760 hours in the year.

[8] For applications and the derivation of hourly costs, see Heffner, G., C.K. Woo, B. Horii and D. Lloyd-Zannetti (1996), "Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," *IEEE Transactions on Power Systems*, PE-493-PWRS-012; Pupp, R., C.K.Woo, R. Orans, B. Horii, and G. Heffner (1995), "Load Research and Integrated Local T&D Planning," *Energy - The International Journal,* 20:2, 89-94; and Orans, R., C.K. Woo and B. Horii (1994), "Targeting Demand Side Management for Electricity Transmission and Distribution Benefits," *Managerial and Decision Economics*, 15, 169-175.

The use of W_h is motivated by the fact that there is no hourly information on other capacity-related attributes at the local T&D level (e.g., relative loss of load probability or expected unserved energy). As T&D planners design the local T&D system to serve peak hours, W_h measures the relative utilization rate of capacity addition.

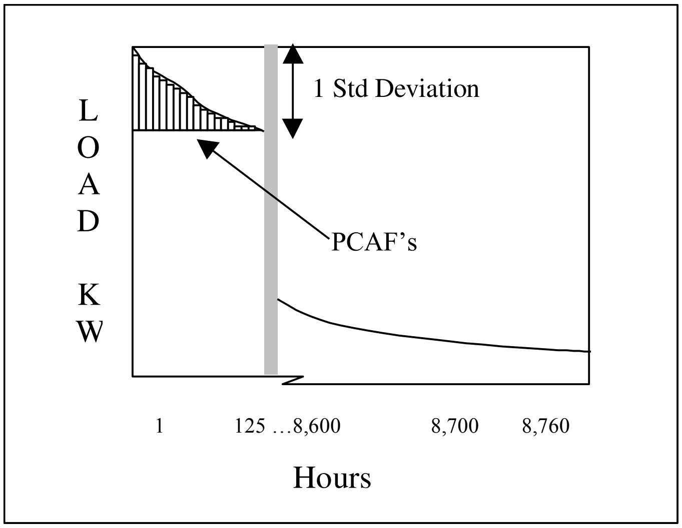

Figure 1: Peak Capacity Allocation Factors (PCAF's)

As W_h is driven by D_h, application of [1] requires the data on hourly loads. For a historic year, it is straightforward to use the recorded data to find W_h. But forecasting W_h for a future year is not simple. The problem at hand is to find a method that can map the PCAF profile $\{W_h\}$ to a temperature profile $\{T_h\}$ for the future year. For the solution to be practical, it must be easy to implement and use so that it readily applies to all weather stations. Equally important is that the solution can easily incorporate updated information on loads and temperatures.

The next section describes the forecasting problem and considers approaches that are based on statistical regressions. We find these approaches difficult to use for the purpose of forecasting W_h. As a result, we recommend a simple approach based on descriptive statistics.

Regression-Based Approaches

Forecasting PCAF requires data on projected hourly loads. A common approach to hourly load forecast is to postulate a hourly load regression model that depicts the relationship between hourly load Y_h and its determining factors, X_h (e.g. hourly temperature T_h and time pattern variables such as hour of day, day of week and month of year):[9]

$$[2] \quad Y_h = F(X_h).$$

Suppose we can estimate [2] for a particular area (e.g., Fresno). The area-specific forecast value for Y_h is y_h based on the area's own projection of $\{T_h\}$ for a particular weather pattern (e.g., cool, normal or hot). If the estimated model's coefficients do not vary geographically, the same model can be used to forecast Y_h for another area (e.g., Sacramento). Otherwise, one has to estimate a Sacramento-specific model in order to make a reasonable forecast for Sacramento.

The forecast value for W_h is

$$[3] \quad w_h = d_h / \Sigma_h\, d_h;$$

[9] See Woo, C.K., P. Hanser and N. Toyama (1986), "Estimating Hourly Electric Load with Generalized Least Squares Procedures," *Energy Journal*, 7:2, 153-170.

where d_h = incremental demand based on y_h. Therefore the accuracy of w_h depends on d_h, which in turn depends on y_h. In other words, if $\{y_h\}$is accurate, we can readily derive an accurate $\{w_h\}$.

Unfortunately, applying the ordinary least squares (OLS) method to the full sample of 8,760 hourly values yields a regression line that tends to pass through the middle of the sample points, see Figure 2. The line lies above the extremely low but below the extremely high values. Thus the estimated model inevitably generates a peak load forecast with downward bias.[10]

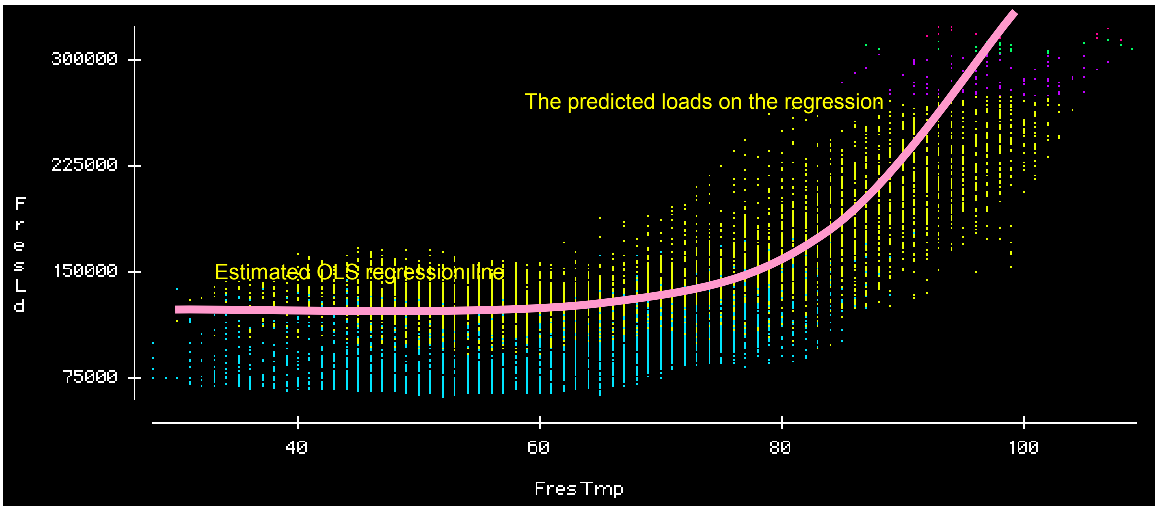

Figure 2: OLS Regression (quadratic form)

One may try to overcome the "central tendency" problem by (a) dividing the full sample into two sub-samples of peak and non-peak hours; and (b) estimating two hourly load regressions using the two sub-samples. This allows the peak hour regression to better track the extremely high values, see Figure 3. While this approach is intuitive, it introduces a new statistical problem commonly known as sample selection bias.[11] The problem arises when the random but unobserved factors that determine the peak hour classification also influence the load of that hour. Correcting the bias involves a two-stage analysis. [12] The resulting models, however, are difficult to use for the purpose of forecasting.[13]

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[10] One may apply the maximum likelihood method to partially correct the problem of "central tendency." But the approach is complicated. See Veall, M. (1983) "Industrial Electricity Demand and the Hopkinson Rate: An Application of Extreme Value Distribution," *Bell Journal of Economics*, 14:2, 427-40.

[11] See Train, K. (1986) *Qualitative Choice Analysis*, Chapter 5 (Cambridge: MIT) and Greene, W.H. (1991) *Econometric Analysis*, Chapter 21 (New York: McMillan).

[12] The first stage estimates the probability of an hour being the peak hour. The second stage is an OLS regression that relates the peak hour's load to the determining factors that include a bias correction term (e.g., the Mills ratio), see Heckman (1979) "Sample .Selection Bias as a Specification Error," *Econometrica* 47, 153-161. The analysis of the non-peak hours is done analogously.

[13] As we do not know a priori whether a given hour is a peak hour, the load forecast for that hour is the sum of (a) Prob(hour = peak hour) * Conditional load forecast if hour = peak hour; and (b) [1 – Prob(hour = peak hour)] * Conditional load forecast if hour = non-peak hour.

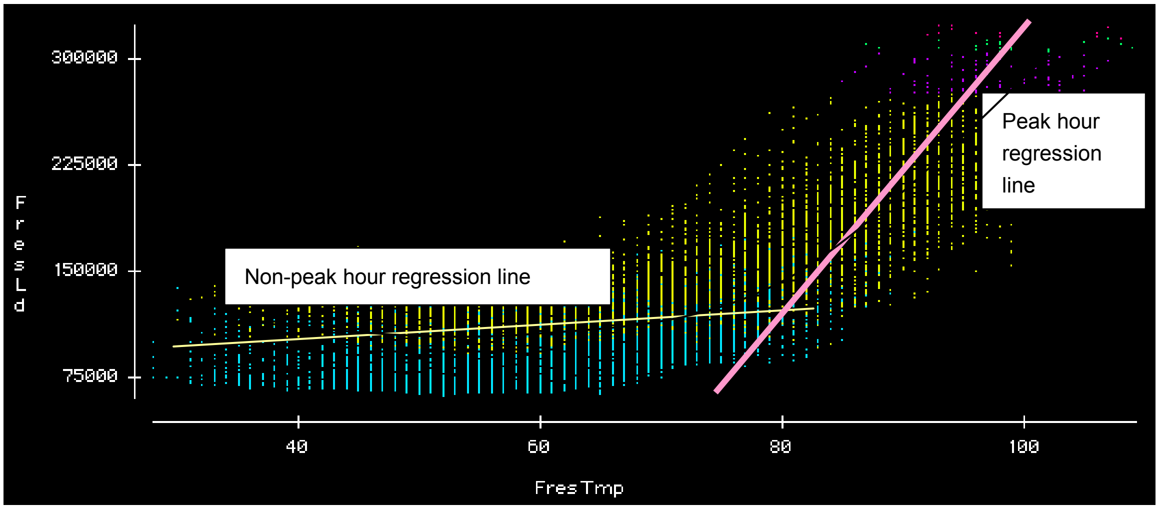

Figure 3 : Peak Hour and Non-Peak Hour Regressions

Another approach is to estimate a PCAF relationship by postulating

$$[4] \quad W_h \quad = \quad G(X_h).$$

Unfortunately, this is even more complicated than estimating [2] for the following reasons. First, zero is the value for the most of the observations on W_h in the full sample of 8,760 hours. Fitting an OLS regression line using the full sample inevitably causes an underestimation of the slope coefficient for temperature, see Figure 4. Second, W_h is either zero or a small fraction. Imposing this prior restriction in the estimation is possible through a two-stage analysis. But the resulting models are complicated and difficult to use to forecast PCAF.[14]

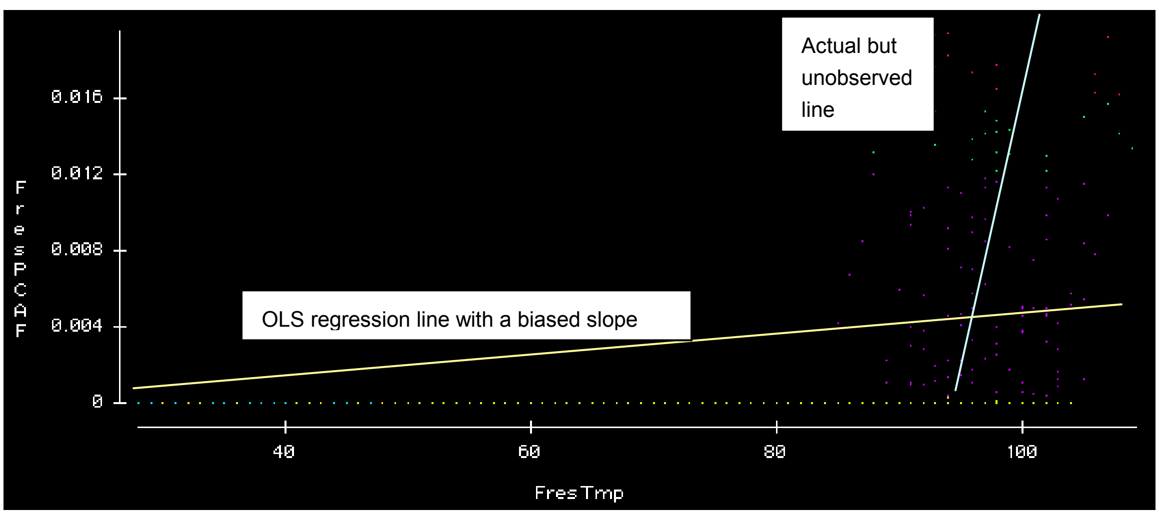

Figure 4: Bias of an OLS Regression Model for PCAFs

[14] The first stage estimates the probability of W_h being strictly positive. The second stage is an OLS regression that relates $\ln(W_h / 1 - W_h)$ to Z_h, the determining factors that include a bias correction term. This regression is estimated using the sub-sample of strictly positive W_h. The forecast of W_h for a given hour is the probability of strictly positive W_h times the conditional expectation of $W_h = \exp. Z_h\beta / (1 + \exp. Z_h\beta)$, where β = estimated coefficients for Z_h in the second stage regression.

Recommendation

The last section indicates that regression based approaches, though seemingly sophisticated, are impractical. Here we consider a simple approach based on descriptive statistics. This approach entails the following steps:

1. Compute {Wh} using the recorded data on hourly loads for a particular area.

2. Classify {Wh} using the observed temperature intervals (e.g., 86-88, 89-90, …, 108-110). The size of the temperature intervals is so chosen that there would be at least PCAF value in each interval. For notational clarity, we use Whj to denote the PCAF values in each interval "j".

3. Compute unadjusted □j = □h Whj / Nj, the mean PCAF for each temperature interval "j" that contains Nj values of PCAFs.

4. Find the adjusted □j = unadjusted □j / □j unadjusted □j, thus ensuring □jadjusted □j = 1.0.

5. Construct a "look-up" table that contains the pairs of temperature interval "j" and the corresponding adjusted □j.

This approach enjoys a number of advantages over the regression-based methods, namely:

- It is computationally straightforward. Thus it is easy to update the look-up table for a particular area.
- It is easy to use. When faced with a temperature profile, one can map a PCAF value from the look-up table to a temperature.
- Unlike a regression model like [2] or [4], it does not impose a functional form on the relationship between PCAF and temperature. Nor does the approach suffer from the "central tendency" problem. If peak temperatures drive peak loads, the look-up table will have large PCAFs for high temperature intervals.

The approach, however, does have two potential drawbacks:

- If the size of temperature interval becomes necessarily in order for each interval to contain some PCAF values, the mapping between PCAFs and temperature becomes imprecise. This problem can be solved in either of two ways. The resulting weights can be smoothed to make a continuous function, or adjacent temperatures can be into broader temperature intervals. For example, 5-degree 'bins' could be created so that the PCAF values for 92 and 95 degrees would be identical.
- The historic temperature profile underling the look-up table is likely different from the projected temperature profile used in the forecast. Thus, the mapped PCAFs (based on the projected temperature profile) may not sum to 1.0. But we can easily remedy the problem by appropriately scaling the mapped PCAFs.

Application

We apply the simple approach to the Fresno data, the following chart shows the resulting costs for each corresponding temperature based on the annual PG&E marginal cost for Fresno of $35.64. There are two refinements that we have applied during the application of this approach.

1. The cost curve is applied only during daytime hours when system peaks are an issue. The hours we chose for this example are 8am to 11pm, 7 days a week. No cost is applied to the other hours of the year.

2. We show a curve that is derived directly from the sum of PCAFs at each temperature, and a derived curve based on the underlying data that has been 'smoothed'. Although both curves will give similar results when applied to the standard, the smoothed curve

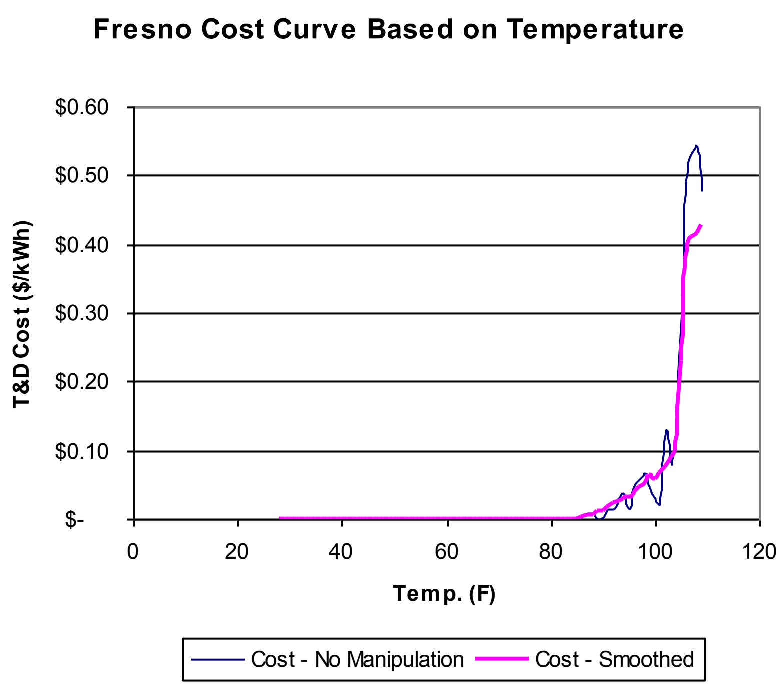

Figure 5: Graph Showing Fresno Cost Curve based on Temperature

A look-up table approach is used to apply this curve. For example, if the temperature in a given hour is 100 degrees, then the corresponding cost from the curve above at 100 degrees is applied to that hour. In this case, the cost to apply is approximately $0.07/kWh.

In order to do a lifecycle analysis for building standards, the cumulative present value of curve can be calculated. The following chart shows the 30-year present value of the costs at a 4% real discount rate. The curve is applied in the same manner.

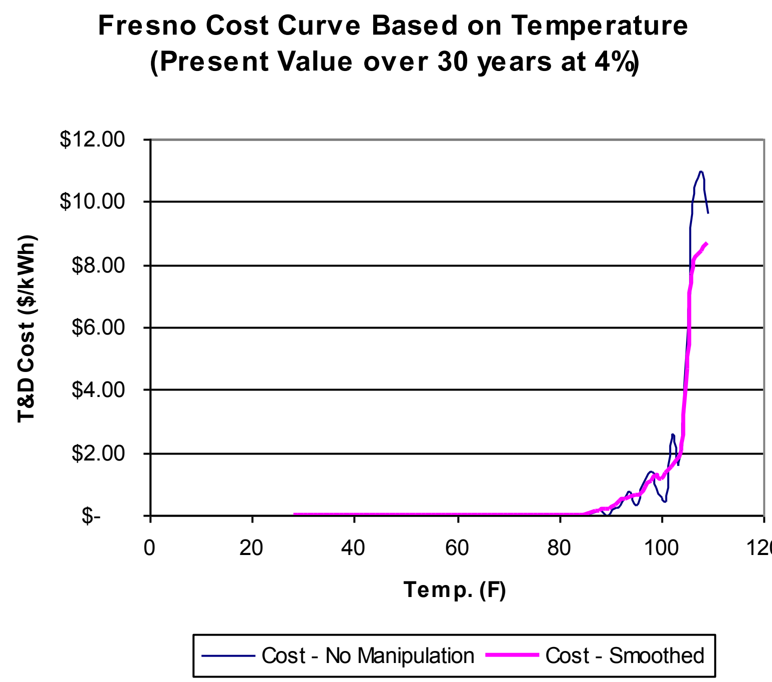

Figure 6: Present Value - Graph Showing Fresno Cost Curve based on Temperature

Regression Formula

For completeness we have also included some regression formula for calculating both loads and PCAFs. Note, however, that we recommend usage of the other approach as detailed in the immediately prior section.

Regression Analysis

For this analysis we examined the impact of multiple drivers on both the area loads and the area peak capacity allocation factors (PCAFs).

Variables examined include:

- Weekday versus weekend
- Business hour (8am to 10pm)
- Cooling hours (12pm to 10pm)
- Subset of hours with temperature greater than or equal to 85 degrees
- Dry bulb temperature
- Cooling deviations: Maximum (Temp[h] – BaseTemp,0), where h is hour, and Basetemp ranged from 85 to 105 degrees
- Temperature lagged by 1 to 8 hours
- 48 hour moving average on temperature (F2MA)
- 72 hour moving average on temperature (F3MA)
- Average temperature for same hour in current and prior day (F2Avg)
- Average temperature for same hour in current and two prior days (F3Avg)

- Hourly Temperature Squared (sqFTp)
- Dummy variables for months of the year
- Dummy variables for days of the week
- Dummy variables for hours (1 to 24) of the day

Regression of Load Results

Table 17: Temperature model correlation coefficients

Dependent variable is: **FresLd**
No Selector
8761 total cases of which 1 is missing
R squared = 87.8% R squared (adjusted) = 87.8%
s = 1.733e4 with 8760 - 24 = 8736 degrees of freedom

Source	Sum of Squares	df	Mean Square	F-ratio
Regression	1.89401e13	23	8.23484e11	2.74e3
Residual	2.62278e12	8736	3.00227e8	

Variable	Coefficient	s.e. of Coeff	t-ratio	prob
Constant	116419	727.4	160	≤ 0.0001
FT-base	4140.4	71.6	57.8	≤ 0.0001
HR4	-56339.1	973.1	-57.9	≤ 0.0001
HR3	-55620.7	969.3	-57.4	≤ 0.0001
HR2	-52135.9	965.7	-54	≤ 0.0001
HR5	-53928.9	976.9	-55.2	≤ 0.0001
HR1	-45509	961.9	-47.3	≤ 0.0001
HR6	-45326.5	980.7	-46.2	≤ 0.0001
Aug	37463.1	814.7	46	≤ 0.0001
Jul	32664.8	829.6	39.4	≤ 0.0001
HR7	-29145.2	982.4	-29.7	≤ 0.0001
Jun	21748.9	787.3	27.6	≤ 0.0001
Sep	16785.6	791.7	21.2	≤ 0.0001
HR23	-12372.7	954.9	-13	≤ 0.0001
HR19	21687.6	957.5	22.7	≤ 0.0001
HR20	20026.6	953.1	21	≤ 0.0001
Saturday	-9636.54	529.9	-18.2	≤ 0.0001
HR18	17080.4	964.9	17.7	≤ 0.0001
HR21	16076.6	951.3	16.9	≤ 0.0001
Mar	-11197.1	693.9	-16.1	≤ 0.0001
HR17	9824.04	968.2	10.1	≤ 0.0001
Apr	-7025.43	716.2	-9.81	≤ 0.0001
sqFTp	3.55006	0.168	21.1	≤ 0.0001
HR8	-12061.7	976.5	-12.4	≤ 0.0001

The above functional form provides a good fit to the temperature data, but does not fit the peak capacity allocation factors (PCAFs) very well. The following figures shows the residual versus predicted plot for the regression equation. The red dots area the observations with the highest PCAF values, followed by the green, and purple values. As can be seen from the graph, the observations that have PCAF values lie predominantly on the high side of the error plot.

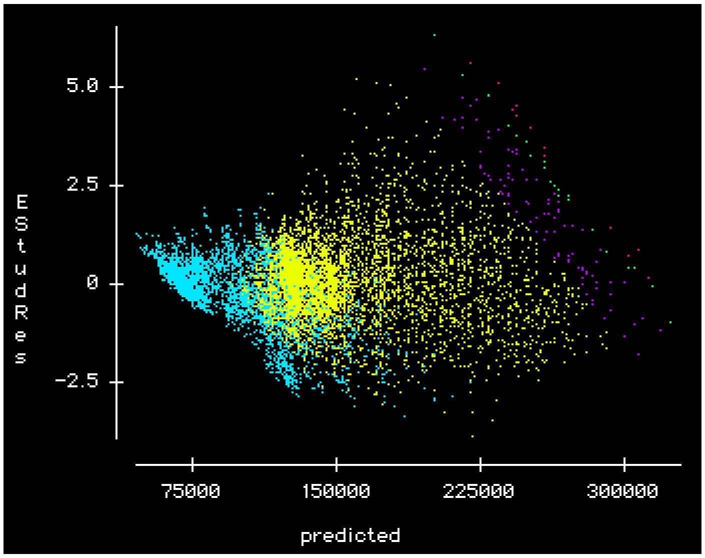

Figure 7: Standardized Residuals and Predicted Values

The regression equation does a good job of estimating the peak load, but does not pick up days when the loads are high, but the temperature is relatively moderate.

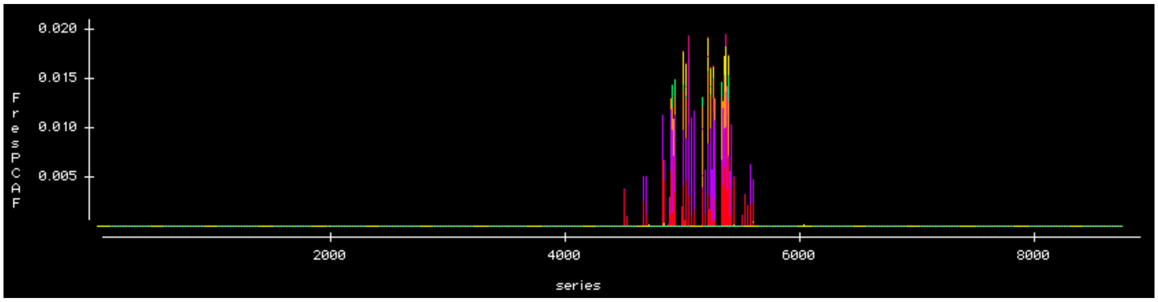

Figure 8: PCAFs for Fresno, 1997

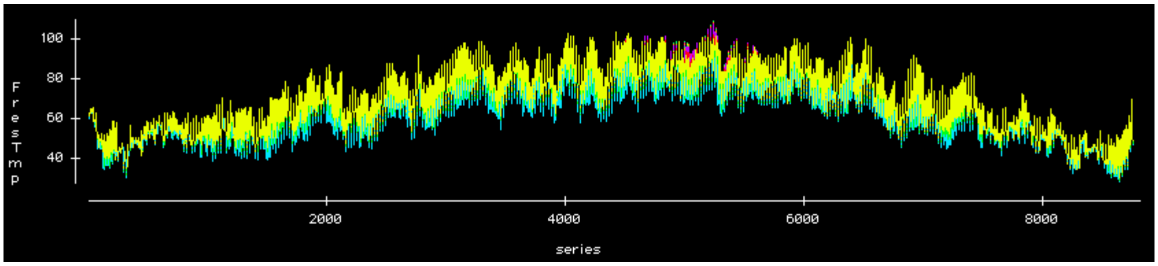

Figure 9: Temperature Profile for Fresno, 1997

Yellow points are between the hours of 8am to 10pm, and the blue points are hours between 10pm and 8am that do not have nay PCAF weights associated with them.

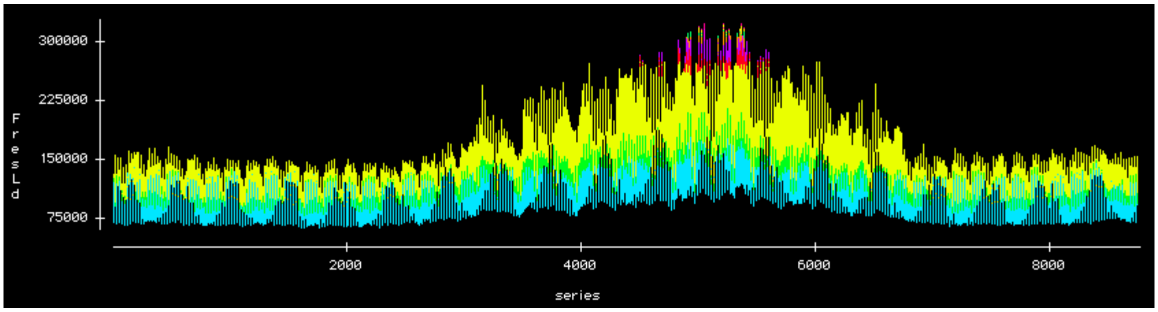

Figure 10: Actual Fresno Loads

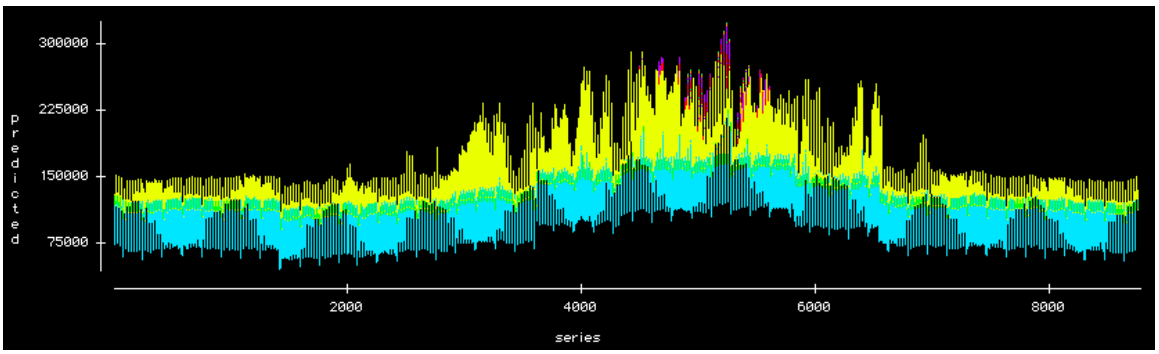

Figure 11: Predicted Fresno Loads

Miscellaneous Descriptive Graphics

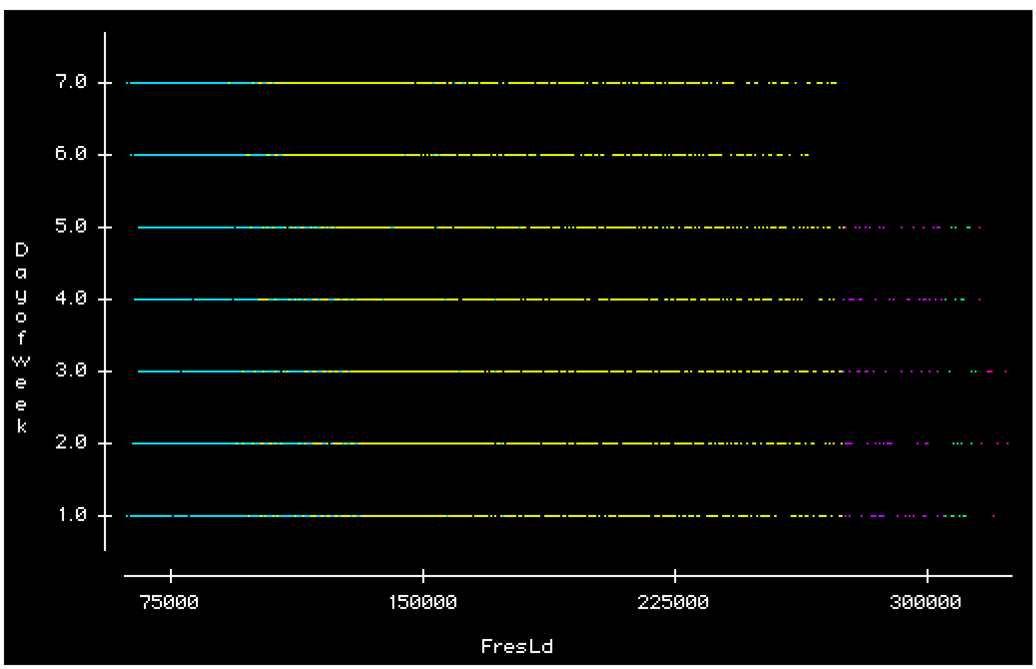

Figure 12: Fresno Loads by Day of the Week (1 = Monday)

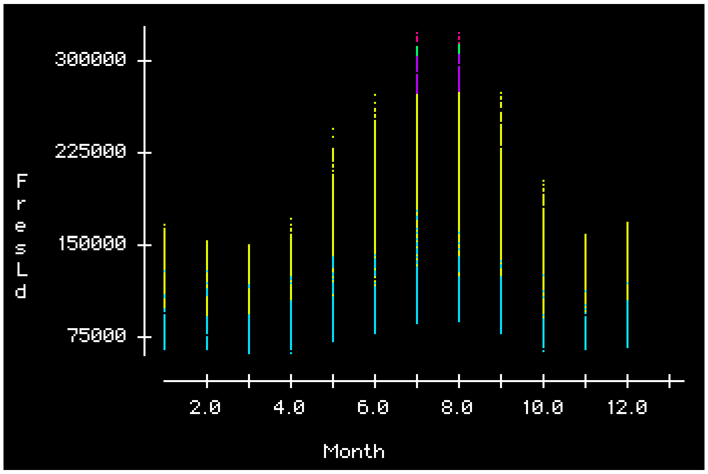

Figure 13: Fresno Loads by Month of the Year

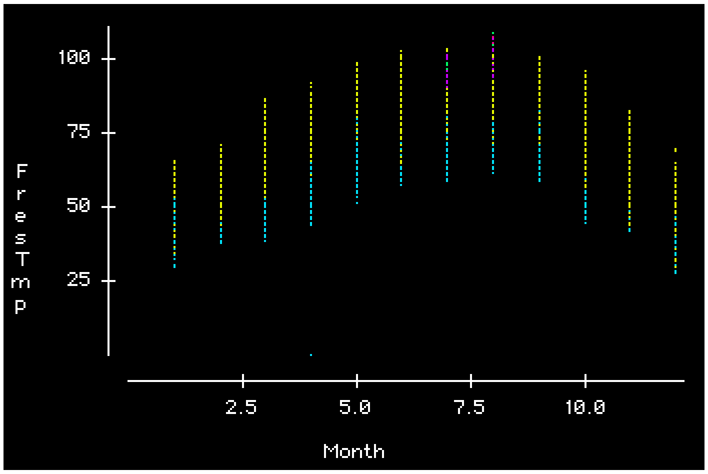

Figure 14: Fresno Temperature by Month of the Year

Table 18 : PCAF Regression Formula

Dependent variable is: FresPCAF
No Selector
8761 total cases of which 1 is missing
R squared = 21.7% R squared (adjusted) = 21.6%
s = 0.001019 with 8760 - 10 = 8750 degrees of freedom

Source	Sum of Squares	df	Mean Square	F-ratio
Regression	0.00251839	9	0.000279821	269
Residual	0.00909117	8750	0.00000103899	

Variable	Coefficient	s.e. of Coeff	t-ratio	prob
Constant	0.000579106	0.00009447	6.13	≤ 0.0001
sqFt-base	0.0000168259	0.0000006795	24.8	≤ 0.0001
FT-base	-0.000183462	0.00001329	-13.8	≤ 0.0001
HR17	0.000330867	0.00005614	5.89	≤ 0.0001
HR18	0.0002637	0.00005593	4.71	≤ 0.0001
HR16	0.000240906	0.00005596	4.31	≤ 0.0001
Fres82-	-0.000311672	0.00005703	-5.47	≤ 0.0001
Aug	0.000567062	0.00004345	13.1	≤ 0.0001
Jul	0.000385555	0.00004415	8.73	≤ 0.0001
F2Avg	-0.00000535035	0.000001038	-5.16	≤ 0.0001

FT-base is the greater of 1) Fresno Temperature – 82 degrees, or 2) 0.

sqFt-base is the square of FT-base

Fres82- is 1 if the temperature if below 82 degrees, 0 elsewise

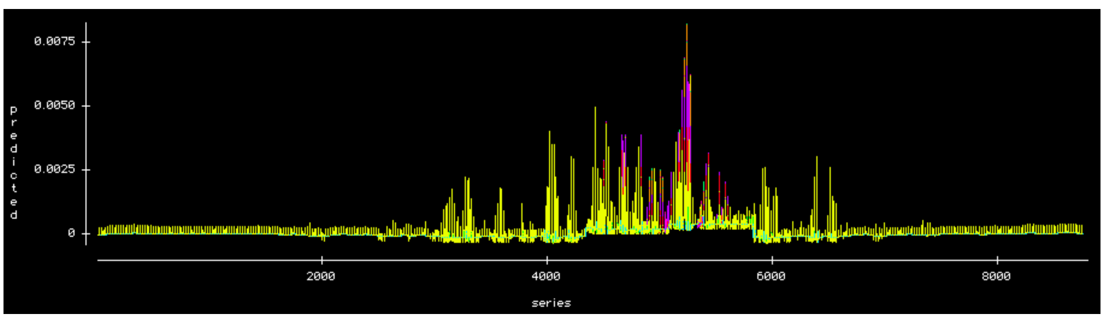

Figure 15: Predicted PCAFs

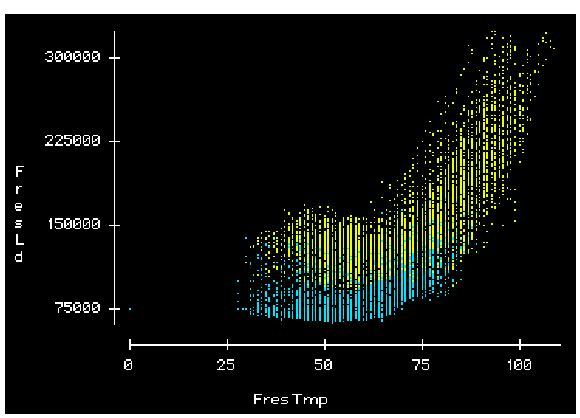

Figure 16: Area Load as a Function of Temperature

Yellow points correspond to loads between 8am and 10pm in the evening. The blue points are all other hours.

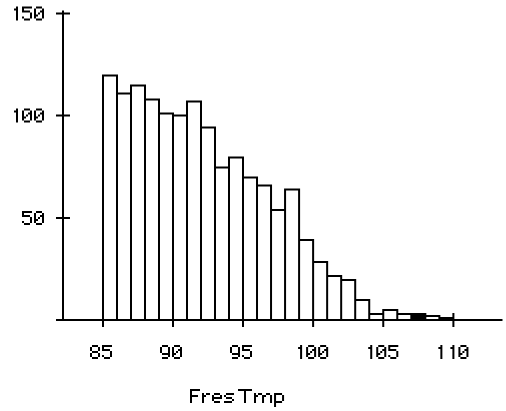

Figure 17: Fresno Temperatures above 85 degrees

PCAF Regression Formulations

Table 19 : Regression with Full Data Set

Dependent variable is: **FresPCAF**
No Selector
8761 total cases of which 1 is missing
R squared = 21.7% R squared (adjusted) = 21.6%
s = 0.001019 with 8760 - 10 = 8750 degrees of freedom

Source	Sum of Squares	df	Mean Square	F-ratio
Regression	0.00251839	9	0.000279821	269
Residual	0.00909117	8750	0.00000103899	

Variable	Coefficient	s.e. of Coeff	t-ratio	prob
Constant	0.000579106	0.00009447	6.13	≤ 0.0001
sqFt-base	0.0000168259	0.0000006795	24.8	≤ 0.0001
FT-base	-0.000183462	0.00001329	-13.8	≤ 0.0001
HR17	0.000330867	0.00005614	5.89	≤ 0.0001
HR18	0.0002637	0.00005593	4.71	≤ 0.0001
HR16	0.000240906	0.00005596	4.31	≤ 0.0001
Fres82-	-0.000311672	0.00005703	-5.47	≤ 0.0001
Aug	0.000567062	0.00004345	13.1	≤ 0.0001
Jul	0.000385555	0.00004415	8.73	≤ 0.0001
F2Avg	-0.00000535035	0.000001038	-5.16	≤ 0.0001

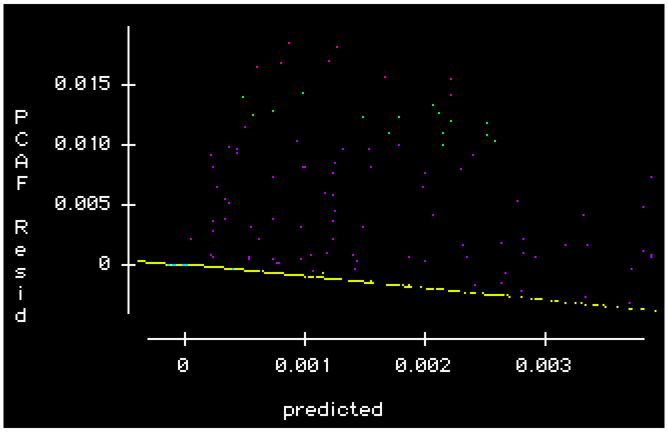

Figure 18 : Residuals

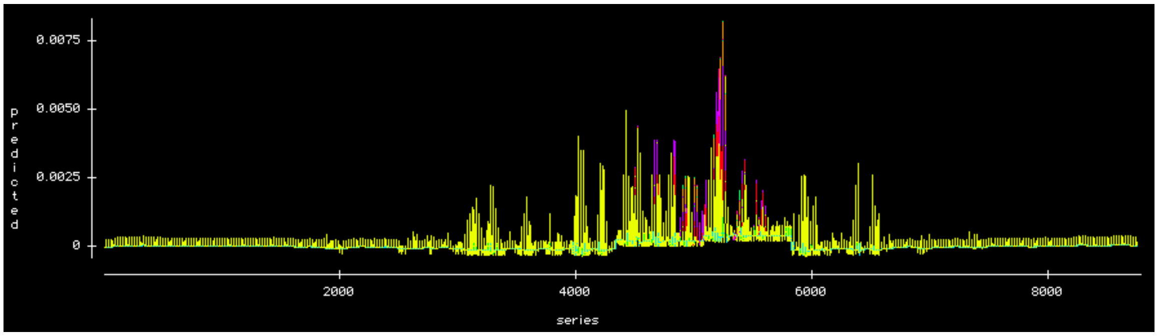

Figure 19: Predicted PCAFs

PCAF Regression using subset of data that is weekday between 8am and 10pm

Table 20 : Weekday Business Hour Regression

Dependent variable is: **1:FresPCAF**
No Selector
R squared = 21.2% R squared (adjusted) = 21.1%
s = 0.001502 with 4015 - 5 = 4010 degrees of freedom

Source	Sum of Squares	df	Mean Square	F-ratio
Regression	0.00242978	4	0.000607444	269
Residual	0.00904487	4010	0.00000225558	

Variable	Coefficient	s.e. of Coeff	t-ratio	prob
Constant	0.00097888	0.0001408	6.95	≤ 0.0001
1:sqFt-base	0.00000779357	0.0000003396	23	≤ 0.0001
1:Aug	0.00121236	0.0000954	12.7	≤ 0.0001
1:Jul	0.000745821	0.00009726	7.67	≤ 0.0001
1:F2Avg	-0.0000177378	0.000002215	-8.01	≤ 0.0001

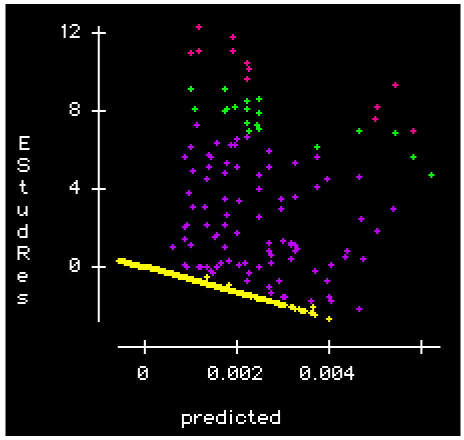

Figure 20: Residuals

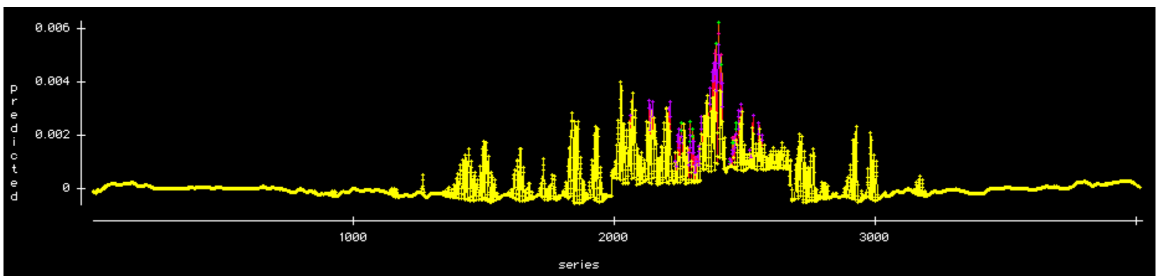

Figure 21 : Predicted PCAFs

Subset of Data that is weekday 8am to 10pm and temperature above 85 degrees

Table 21 : Regression Equation

Dependent variable is: **1:1:FresPCAF**
No Selector
R squared = 18.7% R squared (adjusted) = 18.5%
s = 0.002757 with 1166 - 4 = 1162 degrees of freedom

Source	Sum of Squares	df	Mean Square	F-ratio
Regression	0.0020319	3	0.0006773	89.1
Residual	0.00883418	1162	0.00000760256	

Variable	Coefficient	s.e. of Coeff	t-ratio	prob
Constant	-0.000827858	0.0001321	-6.27	≤ 0.0001
1:1:sqFt-base	0.000008144 29	0.0000007106	11.5	≤ 0.0001
1:1:Aug	0.0017304	0.0002071	8.36	≤ 0.0001
1:1:Jul	0.00106213	0.0002018	5.26	≤ 0.0001

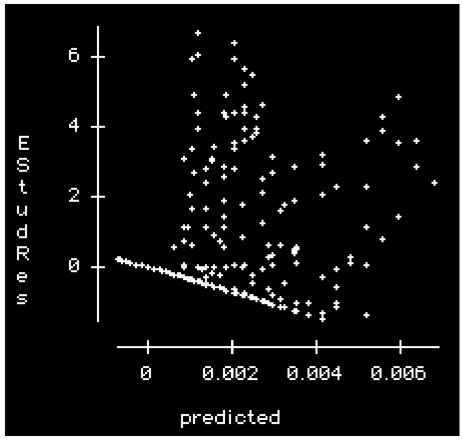

Figure 22: Residuals

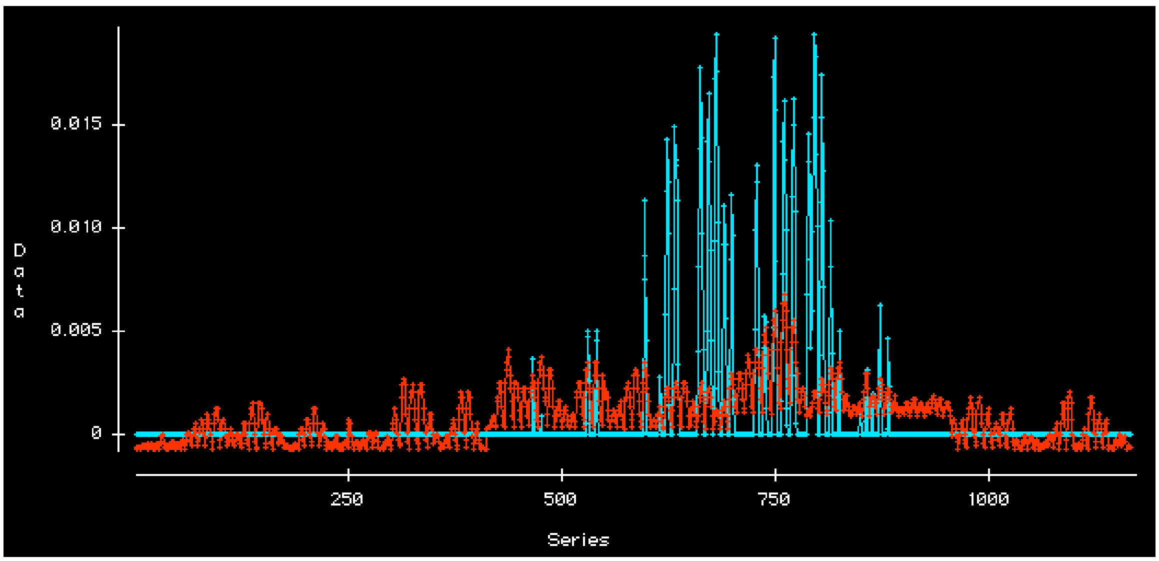

Figure 23: Actual PCAFs (blue) versus Predicted (Red)

3.3.8 Analysis of Area Parameters (Task A1-3c)

Analyze the effect of climate zone, customer density, time-of-use, area growth, and other appropriate parameters and provide written analysis of same.

PG&E is the only utility in California to estimate marginal costs on a geographic basis. SCE has actually intervened in PG&E's rate cases to oppose the introduction of area and time specific marginal costs. Conversations with SCE and CPUC staff verify that the underlying information necessary for calculating area marginal costs is not available in the public domain. There is a remote possibility that area-specific information could be required by the CPUC in the future if Distributed Resources become a large factor in distribution planning and expansion. At the current time, however, this information is not publicly available.

As for the PG&E area-specific marginal costs for transmission and distribution, the PG&E results from their 1996 General Rate Case Filing reinforce the lessons learned in the 1990 GRC filing. Those lessons are as follows:

1. High expenditure areas are not high cost marginal cost areas. The natural assumption is that areas that are receiving high expansion budgets would have the highest marginal costs. This has repeatedly been shown to not be the case. Although the costs are high for such areas in absolute terms, when the marginal costs are calculated on a $/kW basis, the areas typically turn out to be only medium in cost levels. The high cost areas are normally associated with high growth rates. The high growth rates mean that the high cost are spread over a lot of kW of growth. The high $ numerator and the high kW growth denominator essentially cancel each other out.

2. Fast growing areas are not necessarily high marginal cost areas. (see discussion in 1 above)

3. Marginal capacity costs are cyclical in nature. While not represented in the current data, other studies by E3 and PG&E have shown that marginal costs increase as an expansion investment approaches, and decline after the investment is in place. While these costs are well suited to targeted DSM and load reduction programs with limited durations, it is less clear if these costs are a good match to building standards that would have lasting impacts in excess of 20 years.

   For example, a particular area could have a marginal cost of $300/kW-yr just before the construction of a large distribution substation, but in the next year, after the station is built, the marginal cost could drop to zero. Clearly providing a stringent standard in the area (based on the $300 value) for a customer one year, but a lax standard for a customer that comes along a year later does not make sense.

   The recognition of this timing problem is one of the reasons why areas have been restricted to high levels of aggregation (rather than the 200 + planning areas). The averaging of costs is meant to smooth out some of the annual cost variations while capturing some of the cost differences across areas.

PG&E Area-Specific Marginal Costs ($/kW-yr)

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Figure 24: Transmission Marginal Cost as a function of Load Growth

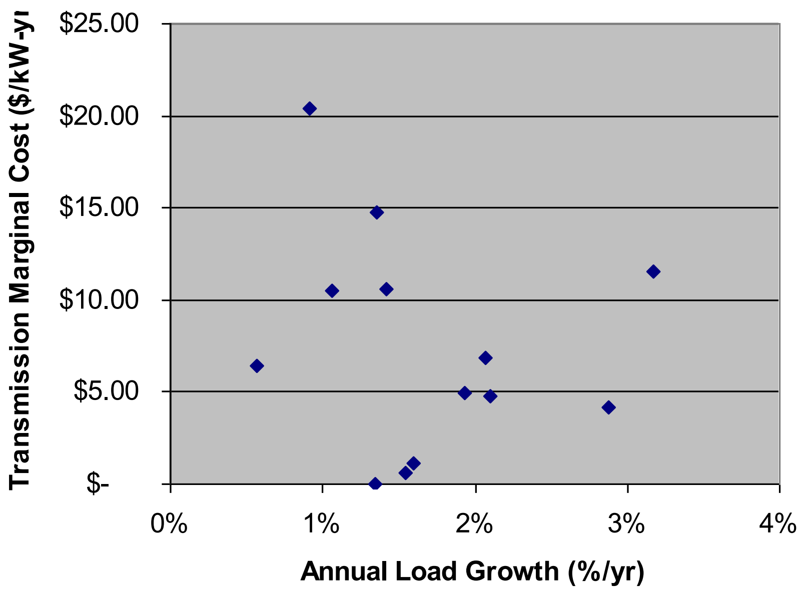


Figure 25: Transmission Marginal Cost as a function of Percent Load Growth

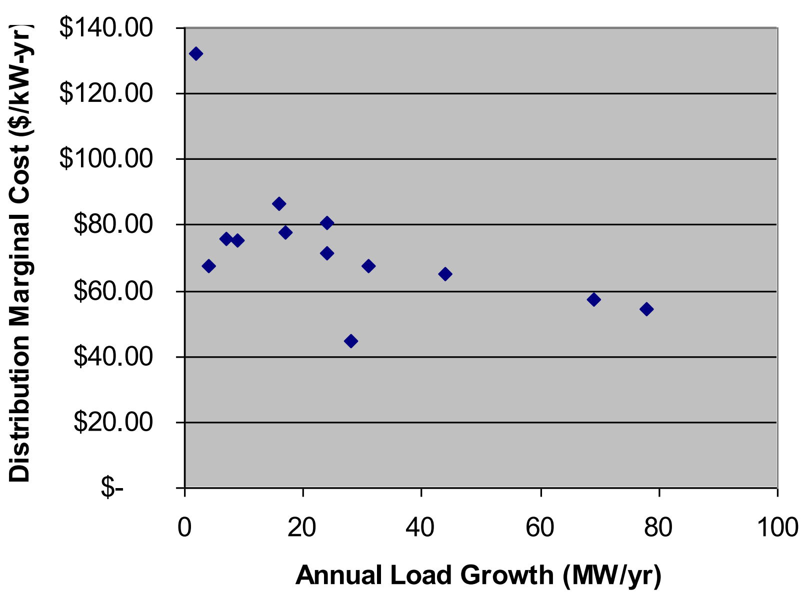


Figure 26: Distribution Marginal Cost as a function of Load Growth

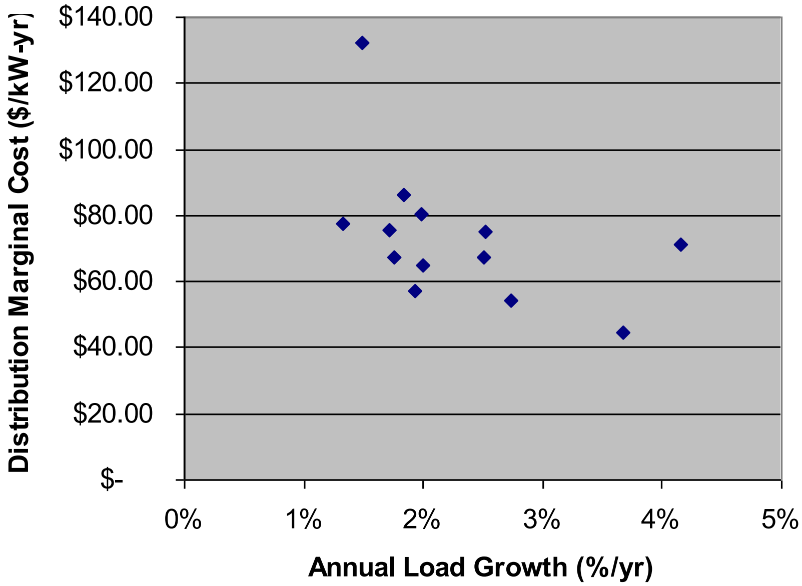


Figure 27: Distribution Marginal Cost as a function of Percent Load Growth

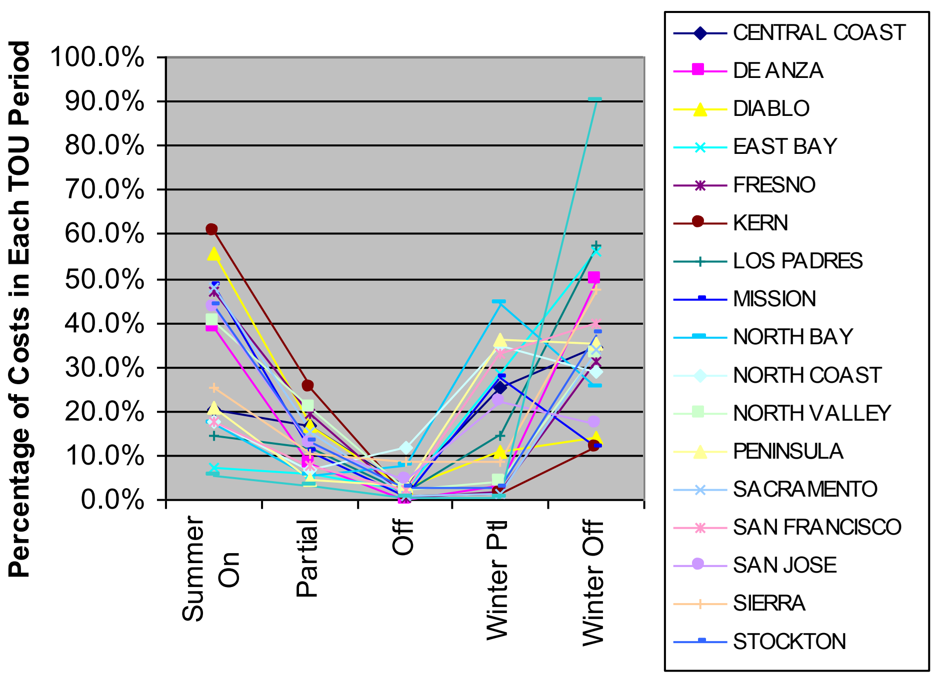


Figure 28: Percentage of Capacity Costs in Each TOU Period

3.3.9 Cost Forecast (Task A1-3d)

Develop a 30 year forecast of these costs. Provide cost data from investor-owned and municipal utilities as specified by the Commission Contract Manager.

Table 22 and Table 23, below, show the 30 year forecast of market prices beyond the year 2002 (years 1998 through 2032). These costs are based on the December 10, 1997 CEC market price forecast and do not include costs of ancillary services. Beyond 2002, the forecast is developed for each TOU period based on a trend of 4.5% escalation.

Table 22: Forecast of Generation Market Price in Southern California

Year	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak
1998	$ 34.00	$ 30.74	$ 23.10	$ 31.79	$ 24.35
1999	$ 31.50	$ 28.78	$ 22.95	$ 30.68	$ 24.65
2000	$ 34.47	$ 30.42	$ 23.74	$ 32.27	$ 25.59
2001	$ 34.16	$ 30.31	$ 24.04	$ 33.19	$ 26.21
2002	$ 38.72	$ 32.89	$ 25.69	$ 36.17	$ 28.07
2003	$ 40.47	$ 34.36	$ 26.85	$ 37.80	$ 29.34
2004	$ 42.29	$ 35.91	$ 28.06	$ 39.50	$ 30.66
2005	$ 44.19	$ 37.53	$ 29.32	$ 41.28	$ 32.03
2006	$ 46.18	$ 39.22	$ 30.64	$ 43.14	$ 33.48
2007	$ 48.26	$ 40.98	$ 32.02	$ 45.08	$ 34.98
2008	$ 50.43	$ 42.82	$ 33.46	$ 47.11	$ 36.56
2009	$ 52.70	$ 44.75	$ 34.96	$ 49.23	$ 38.20
2010	$ 55.07	$ 46.77	$ 36.54	$ 51.44	$ 39.92
2011	$ 57.55	$ 48.87	$ 38.18	$ 53.76	$ 41.72
2012	$ 60.14	$ 51.07	$ 39.90	$ 56.18	$ 43.59
2013	$ 62.84	$ 53.37	$ 41.69	$ 58.70	$ 45.56
2014	$ 65.67	$ 55.77	$ 43.57	$ 61.35	$ 47.61
2015	$ 68.63	$ 58.28	$ 45.53	$ 64.11	$ 49.75
2016	$ 71.71	$ 60.90	$ 47.58	$ 66.99	$ 51.99
2017	$ 74.94	$ 63.64	$ 49.72	$ 70.01	$ 54.33
2018	$ 78.31	$ 66.51	$ 51.96	$ 73.16	$ 56.77
2019	$ 81.84	$ 69.50	$ 54.29	$ 76.45	$ 59.33
2020	$ 85.52	$ 72.63	$ 56.74	$ 79.89	$ 62.00
2021	$ 89.37	$ 75.89	$ 59.29	$ 83.48	$ 64.79
2022	$ 93.39	$ 79.31	$ 61.96	$ 87.24	$ 67.70
2023	$ 97.59	$ 82.88	$ 64.75	$ 91.17	$ 70.75
2024	$ 101.98	$ 86.61	$ 67.66	$ 95.27	$ 73.93
2025	$ 106.57	$ 90.50	$ 70.71	$ 99.56	$ 77.26
2026	$ 111.37	$ 94.58	$ 73.89	$ 104.04	$ 80.74
2027	$ 116.38	$ 98.83	$ 77.21	$ 108.72	$ 84.37
2028	$ 121.62	$ 103.28	$ 80.69	$ 113.61	$ 88.16
2029	$ 127.09	$ 107.93	$ 84.32	$ 118.72	$ 92.13
2030	$ 132.81	$ 112.79	$ 88.11	$ 124.07	$ 96.28
2031	$ 138.79	$ 117.86	$ 92.08	$ 129.65	$ 100.61
2032	$ 145.03	$ 123.16	$ 96.22	$ 135.48	$ 105.14

Table 23: Forecast of Generation Market Price in Northern California

Year	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak
1998	$ 38.37	$ 31.25	$ 24.55	$ 30.06	$ 25.56
1999	$ 34.85	$ 28.35	$ 23.51	$ 28.06	$ 24.93
2000	$ 39.90	$ 30.44	$ 23.90	$ 28.25	$ 25.29
2001	$ 41.50	$ 31.17	$ 24.95	$ 29.31	$ 26.42
2002	$ 49.28	$ 33.31	$ 25.91	$ 30.84	$ 27.76
2003	$ 51.50	$ 34.81	$ 27.07	$ 32.23	$ 29.01
2004	$ 53.81	$ 36.37	$ 28.29	$ 33.68	$ 30.31
2005	$ 56.24	$ 38.01	$ 29.57	$ 35.19	$ 31.67
2006	$ 58.77	$ 39.72	$ 30.90	$ 36.77	$ 33.10
2007	$ 61.41	$ 41.51	$ 32.29	$ 38.43	$ 34.59
2008	$ 64.17	$ 43.37	$ 33.74	$ 40.16	$ 36.15
2009	$ 67.06	$ 45.33	$ 35.26	$ 41.97	$ 37.77
2010	$ 70.08	$ 47.37	$ 36.84	$ 43.85	$ 39.47
2011	$ 73.23	$ 49.50	$ 38.50	$ 45.83	$ 41.25
2012	$ 76.53	$ 51.72	$ 40.23	$ 47.89	$ 43.10
2013	$ 79.97	$ 54.05	$ 42.05	$ 50.04	$ 45.04
2014	$ 83.57	$ 56.48	$ 43.94	$ 52.30	$ 47.07
2015	$ 87.33	$ 59.03	$ 45.91	$ 54.65	$ 49.19
2016	$ 91.26	$ 61.68	$ 47.98	$ 57.11	$ 51.40
2017	$ 95.37	$ 64.46	$ 50.14	$ 59.68	$ 53.72
2018	$ 99.66	$ 67.36	$ 52.40	$ 62.37	$ 56.13
2019	$ 104.15	$ 70.39	$ 54.75	$ 65.17	$ 58.66
2020	$ 108.83	$ 73.56	$ 57.22	$ 68.10	$ 61.30
2021	$ 113.73	$ 76.87	$ 59.79	$ 71.17	$ 64.06
2022	$ 118.85	$ 80.33	$ 62.48	$ 74.37	$ 66.94
2023	$ 124.20	$ 83.94	$ 65.30	$ 77.72	$ 69.95
2024	$ 129.78	$ 87.72	$ 68.23	$ 81.22	$ 73.10
2025	$ 135.62	$ 91.67	$ 71.30	$ 84.87	$ 76.39
2026	$ 141.73	$ 95.79	$ 74.51	$ 88.69	$ 79.83
2027	$ 148.11	$ 100.10	$ 77.87	$ 92.68	$ 83.42
2028	$ 154.77	$ 104.61	$ 81.37	$ 96.85	$ 87.17
2029	$ 161.73	$ 109.31	$ 85.03	$ 101.21	$ 91.10
2030	$ 169.01	$ 114.23	$ 88.86	$ 105.76	$ 95.20
2031	$ 176.62	$ 119.37	$ 92.86	$ 110.52	$ 99.48
2032	$ 184.57	$ 124.74	$ 97.04	$ 115.50	$ 103.96

3.3.10 Scenarios

Table 24: Present Value of Southern California Market Clearing Price by TOU Period and Scenario ($/kWh)

Real Discount Rate	PV Range	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak
2.00%	2002	$0.0387	$0.0329	$0.0257	$0.0362	$0.0281
	15-Year PV	$0.5075	$0.4310	$0.3367	$0.4741	$0.3679
	30-Year PV	$0.8846	$0.7512	$0.5869	$0.8264	$0.6413
3.00%	2002	$0.0387	$0.0329	$0.0257	$0.0362	$0.0281
	15-Year PV	$0.4761	$0.4044	$0.3159	$0.4448	$0.3452
	30-Year PV	$0.7818	$0.6639	$0.5187	$0.7303	$0.5667
4.00%	2002	$0.0387	$0.0329	$0.0257	$0.0362	$0.0281
	15-Year PV	$0.4478	$0.3803	$0.2971	$0.4183	$0.3246
	30-Year PV	$0.6964	$0.5914	$0.4620	$0.6505	$0.5048

Table 25: Present Value of Northern California Market Clearing Price by TOU Period and Scenario ($/kWh)

Real Discount Rate	PV Range	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak
2.00%	2002	$0.0493	$0.0333	$0.0259	$0.0308	$0.0278
	15-Year PV	$0.6459	$0.4365	$0.3396	$0.4042	$0.3638
	30-Year PV	$1.1258	$0.7609	$0.5919	$0.7045	$0.6341
3.00%	2002	$0.0493	$0.0333	$0.0259	$0.0308	$0.0278
	15-Year PV	$0.6059	$0.4095	$0.3186	$0.3792	$0.3413
	30-Year PV	$0.9949	$0.6724	$0.5231	$0.6226	$0.5604
4.00%	2002	$0.0493	$0.0333	$0.0259	$0.0308	$0.0278
	15-Year PV	$0.5698	$0.3851	$0.2996	$0.3566	$0.3210
	30-Year PV	$0.8862	$0.5990	$0.4659	$0.5546	$0.4992

Table 26: 30-Year Present Value of PG&E T&D Capacity Costs (4% Real Discount Rate)

$/kWh	Summer On-Peak	Partial-Peak	Off-Peak	Winter Partial Peak	Off-Peak
Central Coast	$ 0.3461	$ 0.2437	$ 0.0145	$ 0.1480	$ 0.1195
De Anza	$ 0.4849	$ 0.0874	$ -	$ 0.0144	$ 0.1268
Diablo	$ 0.4919	$ 0.1257	$ 0.0068	$ 0.0331	$ 0.0253
East Bay	$ 0.0637	$ 0.0445	$ 0.0055	$ 0.0872	$ 0.1008
Fresno	$ 0.5012	$ 0.1762	$ 0.0014	$ 0.0069	$ 0.0678
Kern	$ 0.6449	$ 0.2325	$ 0.0024	$ 0.0051	$ 0.0256
Los Padres	$ 0.2447	$ 0.1714	$ 0.0087	$ 0.0840	$ 0.1992
Mission	$ 0.6062	$ 0.1180	$ 0.0039	$ 0.1193	$ 0.0302
North Bay	$ 0.1528	$ 0.0428	$ 0.0200	$ 0.1365	$ 0.0459
North Coast	$ 0.1586	$ 0.0524	$ 0.0303	$ 0.1094	$ 0.0539
N. North Valley	$ 0.3262	$ 0.1453	$ 0.0048	$ 0.0113	$ 0.0546
S. North Valley	$ 0.3029	$ 0.1349	$ 0.0045	$ 0.0105	$ 0.0507
Peninsula	$ 0.2844	$ 0.0505	$ 0.0129	$ 0.1702	$ 0.0979
Sacramento	$ 0.2968	$ 0.0820	$ 0.0018	$ 0.0033	$ 0.0427
San Francisco	$ 0.2385	$ 0.0884	$ 0.0088	$ 0.1548	$ 0.1103
San Jose	$ 0.5440	$ 0.1384	$ 0.0154	$ 0.0957	$ 0.0436
Sierra	$ 0.2793	$ 0.0976	$ 0.0262	$ 0.0322	$ 0.1068
Stockton	$ 0.5051	$ 0.1306	$ 0.0087	$ 0.0115	$ 0.0883
Yosemite	$ 0.0600	$ 0.0291	$ 0.0012	$ 0.0019	$ 0.1956

3.4 Marginal Costs for Natural Gas (Task A2)

1. Identify present and future sources of publicly available natural gas cost data.

1a. Identify present and future sources of publicly available utility and supplier natural gas cost data.

The following sources offer publicly available data on utility and/or supplier natural gas costs. For this report CPUC and FERC information was used.

CPUC SDG&E, SCG and PG&E file monthly tariffs to the CPUC which show the gas costs that are used to calculate the monthly gas procurement charges for the utilities' gas customers.

FERC Form 423 "Monthly Report of Cost and Quality of Fuels for Electric Power Plants" Monthly reports by utilities which specify the cost, quantity and source of fuel purchases for plants at least 50 MW in size are available 95 days after filing with FERC. Data for PG&E, SCG, SDG&E, SMUD, LADWP, and the Imperial Irrigation District, from January 1996 to June 1998, are included in the Microsoft Excel file gas_data.xls, on the sheet labeled "form 423". A sample is shown below.

Table 27: Sample of FERC Form 423

Company Name	Plant Name	Year	Month	Fuel Type	Source Name	Quantity mcf	Btu Content	Cost cents/mmbtu
Imperial Irrigation District	El Centro	96	4	NG	PAN ENERGY	223.4	1017	$184.60
Imperial Irrigation District	El Centro	96	5	NG	CHEVRON	55.1	1017	$199.80
Imperial Irrigation District	El Centro	96	5	NG	PAN ENERGY	67.5	1017	$199.80
Imperial Irrigation District	El Centro	96	6	NG	CHEVRON	19	1012	$254.10
Imperial Irrigation District	El Centro	96	6	NG	MORGAN STANLEY	156.2	1012	$254.10
Imperial Irrigation District	El Centro	96	6	NG	PAN ENERGY	113.1	1012	$254.10
Imperial Irrigation District	El Centro	96	7	NG	MORGAN STANLEY	595.8	1009	$174.70
Imperial Irrigation District	El Centro	96	8	NG	MORGAN STANLEY	594.6	1008	$199.50
Imperial Irrigation District	El Centro	96	8	NG	PAN ENERGY	172.3	1008	$199.50
Imperial Irrigation District	El Centro	96	8	NG	WESTERN GAS RESOURC	9.7	1008	$199.50
Imperial Irrigation District	El Centro	96	9	NG	MORGAN STANLEY	318.8	1010	$240.50
Imperial Irrigation District	El Centro	96	10	NG	MORGAN STANLEY	70.7	1009	$363.40
Imperial Irrigation District	El Centro	96	10	NG	NATIONAL GAS CLEARING	71.7	1009	$363.40
Imperial Irrigation District	El Centro	96	10	NG	PAN ENERGY	32.6	1009	$363.40

FERC Interstate Pipeline Tariff Sheets. Interstate pipeline companies must file tariff sheets with FERC. These sheets are publicly available and can be downloaded from FERC's website.

FERC Form 1 - Includes fuel type, average delivered cost of fuel (some utilities decline to report this data), and average fuel cost per kWh generated. Form 1s and the software for viewing them can be downloaded from the Commission Issuance Posting System (CIPS) on the FERC website (www.ferc.fed.us). Filed annually.

EIA Form 176 "Annual Report of Natural and Supplemental Gas Supply and Disposition"

EIA Natural Gas Annual

EIA State Energy Price and Expenditure Report

1b. Obtain publicly available data on costs for IOUs and suppliers for: Natural gas production, Transmission, Distribution, Storage, and Customer Service.

CPUC staff stated that Biennial Cost Allocation proceedings may provide future data that detail the marginal costs of natural gas transmission, distribution, storage and customer service. The marginal cost information is currently required because of its incorporation in retail ratemaking. As PBR proposals evolve in the gas market, however, the need for such data may decline in the future.

All the data listed below can be found in the Microsoft Excel file gas_data.xls, on the utility cost sheets.

CPUC Decision 97-04-082, April 23, 1997 (Southern California Gas and SDG&E 1996 BCAP filing). Appendix D, page 14 lists the marginal costs for Southern California Gas Company for distribution, transmission, and storage. Appendix E, page 2 of this document shows for San Diego Gas & Electric long-run marginal costs by customer class for customer costs, distribution costs, and transmission costs.

CPUC Monitoring and Evaluation Report, 1997-1998 Record Period, on Southern California Gas Company Gas Cost Incentive Mechanism, Office of Ratepayer Advocates, September 23, 1998. This report details all of Southern California Gas Company's gas purchase costs (commodity, commodity adjustments, transport and reservation costs) on a monthly basis. Exhibit 4- summarizes total actual costs.

CPUC Monitoring and Evaluation Report on San Diego Gas and Electric Company's Performance Based Ratemaking Gas Procurement, Office of Ratepayer Advocates, January 21, 1997. This report details SDG&E's gas costs for the period August 1, 1995 through July 31, 1996. Exhibits A-13-1 and A-13-3 show monthly commodity purchase volumes and costs, transport charges, inter-state demand/reservation fees, and intrastate charges.

CPUC Monitoring and Evaluation Report on San Diego Gas & Electric Company's Performance-Based Ratemaking Gas Procurement Annual Report, Office of Ratepayer Advocates, January 15, 1998. This report covers the period August 1996 – July 1997. Exhibits 3, 3-1, 5 and 6 break out on a monthly basis the total volume purchased and the total costs for commodity, interstate transport, interstate reservation and intrastate transport, demand, and various other fees and charges.

Table 28: PG&E Gas Marginal Costs

Marginal Costs (unreconciled, unequalized) ($ per Therm)	Residential	Sml Comm
Customer	$0.10184	$0.00888
Distribution	$0.05887	$0.02053
Local Transmission	$0.01352	$0.00451
Backbone Transmission	$0.00600	$0.00196
Bundled Storage	$0.00405	$0.00133
Total Transportation and Storage Cost	*$0.18427*	*$0.03721*
September 1, 1998 Procurement Cost	$0.22914	$0.22914
Total Bundled Cost	$0.41341	$0.26635

Source: Ray Blatter, PG&E Rates Department, Gas Rate Design

Table 29: SoCalGas Marginal Costs

SCG			
Decision 97-04-082			
Appendix D, page 14			
Marginal Costs		Units	1996 Costs (96$)
Common Distribution			
	Medium Pressure	$/Mcfd of peak day demand	102.72429
	High Pressure	$/Mcfd of peak month demand	0.52549
Transmission			
	Northern Zone Marginal Cost	$/Dth of cold year throughput	0.07258
	Base Rate Marginal Cost	$/Dth of cold year throughput	0.08946
	Zone Rate Credit	$/Dth of cold year throughput	-0.01687
Storage			
Inventory			
	Marginal Cost	$/Mcf of Inventory Reservation	0.36188
Injection Capacity			
	Marginal Cost	$/Mcf of Injection Reservation	32.04147
	Variable O&M	$/Dth of Injection	0.04394
Withdrawal Capacity			
	Marginal Cost	$/Mcfd of W/D Res. PD Demand	8.55393
	Variable O&M	$/Dth of Withdrawal	0.0189
Load Balancing			
	Core	$/Dth of Average year throughput	0.00866
	Noncore	$/Dth of Average year throughput	0.02115

Source: Decision 97-04-082, April 23, 1997 (Southern California Gas and SDG&E 1996 BCAP filing).

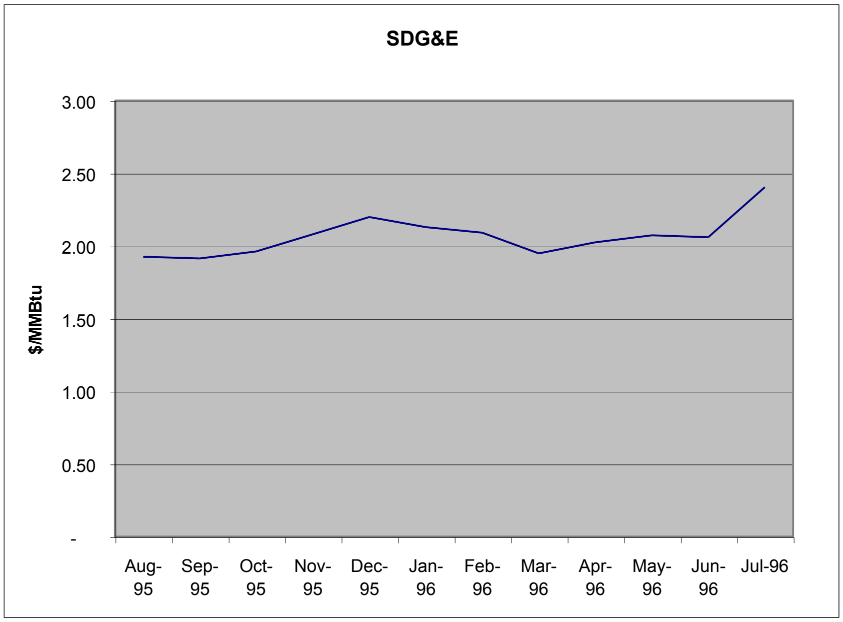
SCG's average procurement cost for 1997-1998 was 2.66 $/Dth.

Source: Monitoring and Evaluation Report, 1997-1998 Record Period, on Southern California Gas Company Gas Cost Incentive Mechanism, Office of Ratepayer Advocates, September 23, 1998.

Table 30: SDG&E Gas Transportation Marginal Costs

SDG&E			
Decision 97-04-082			
Appendix E, page 2, Long Run Marginal Costs - Eff. Jan.1, 1997			
Customer Costs		Resid	GN-1
	$/Customer-Year	99.59	127.91
Distribution Costs			
	High Pressure $/Mcfd	39.98	39.98
	Medium Pressure $Mcfd	98.78	98.78
Transmission			
	$/Mcf (Cold Year CPM)	1.89	1.89
	$/mtherm	1.08	1.08

Source: Decision 97-04-082, April 23, 1997 (Southern California Gas and SDG&E 1996 BCAP filing).



source: Monitoring and Evaluation Report on San Diego Gas and Electric Company's Performance Based Ratemaking Gas Procurement, Office of Ratepayer Advocates, January 21, 1997.

Figure 29: SDG&E Procurement Costs

Table 31, below, shows a summary of the natural gas transportation and storage marginal costs for the three gas utilities in the State. The costs for SCG and SDG&E were taken from rate filing proceedings.

Table 31: Summary of Natural Gas Transportation and Storage Marginal Costs (1998$)

	Residential	Commercial	
PG&E	$ 0.1843	$ 0.0372	$/therm
SCG	$ 0.1239	$ 0.0913	$/therm
SDG&E	$ 0.1444	$ 0.0889	$/therm

PG&E Source: Ray Blatter, PG&E Rates Department, Gas Rate Design

SCG / SDG&E Source: PUC Decision 97-04-082 April 23, 1997 Application to Revise Rates Appendix D, Appendix E

1c. Identify average natural gas costs and reasons why average costs would not equal marginal costs.

Sources for average natural gas costs include:

CPUC SDG&E, SCG and PG&E file monthly tariffs to the CPUC which show the gas costs that are used to calculate the monthly gas procurement charges for the utilities' gas customers.

CPUC ORA Monitoring and Evaluation Reports for SCG and SDG&E include utility average cost data.

EIA Form 176 "Annual Report of Natural and Supplemental Gas Supply and Disposition"

EIA Natural Gas Annual

EIA State Energy Price and Expenditure Report

FERC Form 423 "Monthly Report of Cost and Quality of Fuels for Electric Power Plants" Monthly reports by utilities are available 95 days after filing with FERC

FERC Form 1 - Includes fuel type, average delivered cost of fuel (some utilities decline to report this data), and average fuel cost per kWh generated. The data under tab "form 423" can be used to calculate average costs by utility, source, or date for bulk purchases.

Table 32: Gas Average Rates

	PG&E	SoCal Gas	SDG&E
Residential			
Procurement	$ 22.91	$ 19.21	$ 22.92
Transportation	$ 37.50	$ 50.95	$ 40.48
Total Bundled	$ 60.41	$ 70.16	$ 63.40
Commercial			
Procurement	$ 22.91	$ 19.21	$ 22.92
Transportation	$ 37.89	$ 37.99	$ 31.98
Total Bundled	$ 60.81	$ 57.19	$ 54.90

Source: PG&E From Ray Blatter, Rates Department

So Cal Gas Core Transportation Rates from SoCal Gas and SDG&E 1996 BCAP, Appendix B, and Appendix C

1d. Obtain marginal cost data from IOUs and suppliers for: Production, Transmission, Storage, Distribution, Customer-related new construction, and Customer Service

Marginal Cost information is shown in the following tables above:

- Table 28: PG&E Gas Marginal Costs
- Table 29: SoCalGas Marginal Costs
- Table 30: SDG&E Gas Transportation Marginal Costs
- Figure 29: SDG&E Procurement Costs

Marginal cost data is also included in the utility cost sheets in the file Gas_data.xls.

1e. Obtain most recent annual natural gas price forecast from Fuels Resource Office and monthly natural gas price forecast consistent with that annual forecast.

CEC Natural Gas Market Outlook, June 1998. Available on the CEC website.

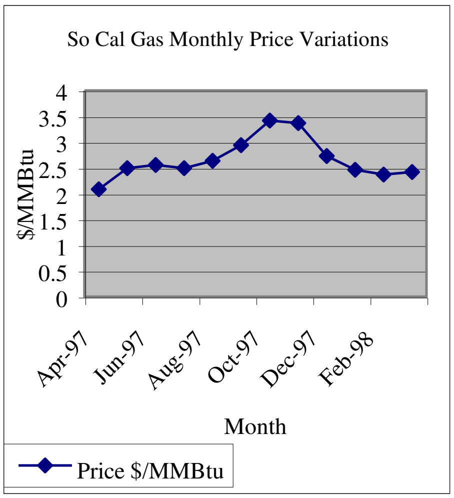
The CEC monthly natural gas price forecast for each utility is included in the file Gas_data.xls.

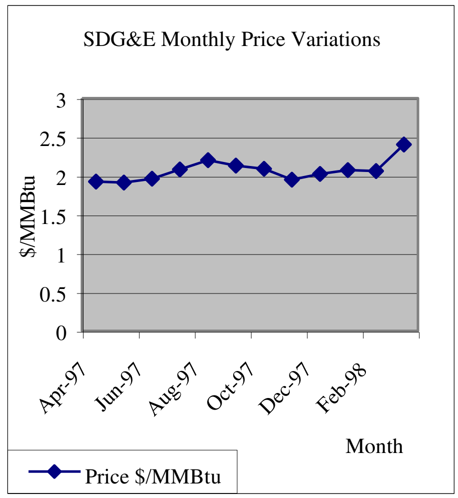
3.4.1 Drivers of Variations in Natural Gas Costs (Task A2.2)

Identify factors which contribute to variations in natural gas costs, including but not limited to season, geographic region, bulk purchases, and customer class.

The file Gas_data.xls, sheet "a2.2", contains plots of gas costs, by utility service territory, according to volume purchased and month.

Figure 30 : Monthly Procurement Prices





As shown in the graphics in Figure 30, there is a greater degree of monthly price variation for SCG than for SDG&E. SCG shows a strong winter peak in costs. SDG&E shows a winter peak, but also an increase in price at the end of the data series. SDG&E shows a stronger relationship between price and volume, but for both utilities the relationship is not a strong one. The table below shows summary statistics on price and volume purchases from three major gas suppliers. As shown, the average cost varies significantly between suppliers.

Geographic Region: Geographic variation may be attributable to differences in the wholesale sources used by each utility. Within each utility, the source of gas purchases varies over the year. PG&E operates their bulk system to use Canadian gas on a baseload basis, and swing on the El Paso gas. This dual procurement from both the Canadian and South West US basin is done for cost minimization reasons, but PG&E does not consider customers located near the more expensive South West gas to be any more costly to serve, than customers in the north. Even though PG&E advocates area-specific costs on the electric side, they state that the physical nature of the gas system does not lend itself to a geographically dispersed analysis in either practical or theoretical terms.

Table 33: Statistics on Monthly Gas Purchases

	PG&E Gas	SO. CALIF. GAS CO.	SDG&E
Gas Costs cents/MMBtu			
Average	265.6257	333.1261	284.475
Max	456.1	981.1	503.8
Min	200	153.9	206.7
Quantity mcf			
Average	1530.708	1059.232	1881.928
Max	6577.277	7128	3300.727
Min	0.001	1	1002

Source: FERC Form 423, January 1996 – June 1998.

Bulk Purchases: Within each utility, data do not show a strong relationship between size of purchase and price. However, there is a difference in the price paid for bulk purchases between the utilities. While there is theoretical support for such a hypothesis (lower per unit transaction costs, greater bargaining power with suppliers etc), gas prices also reflect the contract term, point of delivery, source, and natural gas forward prices at the time a contract is signed. FERC requires utilities to report on a monthly basis the cost and quantity of fuel purchases. A cursory review of the cost of pipeline purchases for utilities in California shows a wide variation in price for smaller volume purchases, and in general shows a convergence to lower prices in the $2-$3/MMBtu price range at larger volumes.

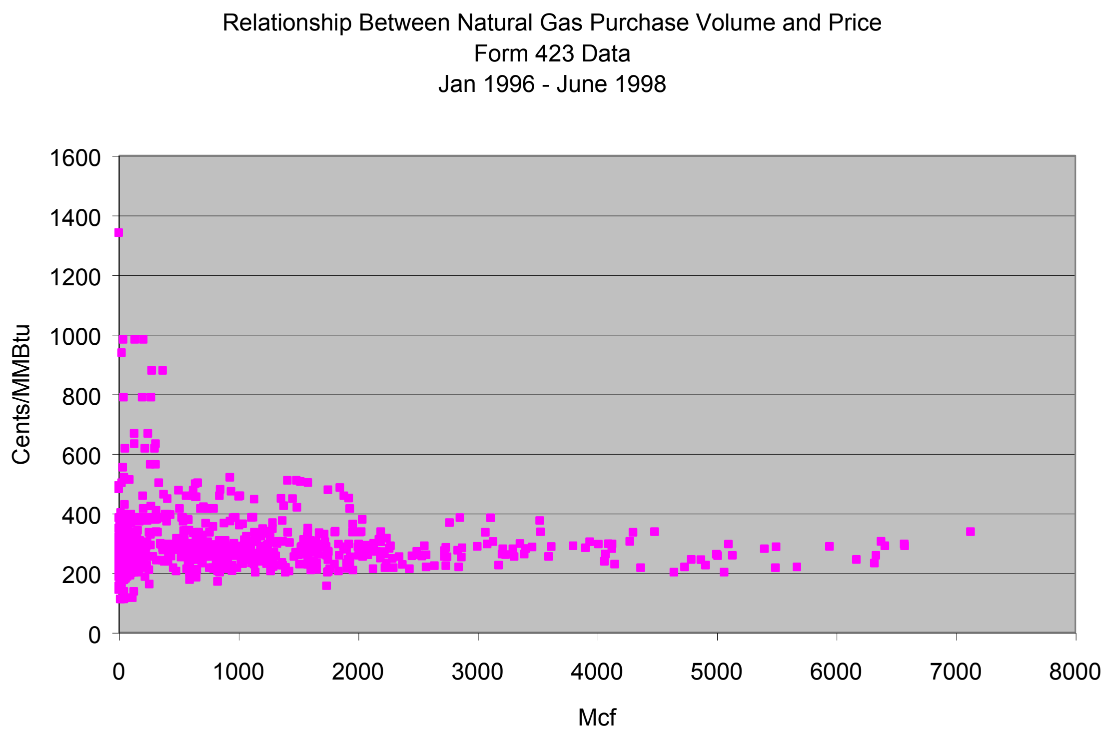


Figure 31: Relationship between Natural Gas Purchase Volume and Price

Note that in the early years of gas deregulation, customers were able to attain cost savings relative to utility bundled procurement rates (utility commodity and transportation). These savings came through the formation of “buying clubs” and gas aggregators that were able to beat the utility commodity price (transportation prices are the same as under bundled service). As the market has evolved, however, and the utility commodity price has approached the market price, the numerous core aggregators have declined to only three in the entire state of California, with less than 5% participation by core customers.

Customer Class: While customer class is a strong indicator of retail RATES, its predictive ability for marginal costs is due mostly to the consumption pattern of customers in a customer class, rather than the actual assignment of a customer to a customer class. In other words, a customer class has a certain cost pattern, not because of the existence of a “class” but because of the aggregate usage pattern of the customers comprising the class. A customer class is not a causative factor. That being said however, a customer class may serve as a shorthand descriptive variable that captures numerous differences in causative factors relating to a particular customer class.

To the extent that residential customers require more storage, or consume more gas during the expensive summer months, their gas cost would be higher than a commercial customer that consumes gas on a more uniform basis. In addition, smaller usage customers (such as residential) would have fewer therms over which to recover fixed distribution costs, and would therefore attract higher transportation and delivery costs (on a cents per therm basis)

3.4.2 Analysis of Area Gas Cost Parameters (Task A2.3)

Review Data for both residential and non-residential customers as they relate to system utilization and expansion needs as a function of climate zone, customer density, time-of-use, area growth, and other appropriate parameters and provide written analysis of the same.

Because of the physical nature of the gas system, such as the inherent storage inertia of the pipe, and the potential for increasing throughput with higher pressures, the gas distribution system is not as sensitive to the timing of demand as the electric system. There are some seasonal differences in the procurement price of gas, and this varies depending on the utilities’ sources of gas and storage capacity. Discussions with PG&E staff indicate that gas marginal costs are not differentiated by area (or at least not differentiated enough to make the distinction meaningful). Customer density can have some obvious impacts on per customer connection and distribution costs, but no information was available to quantify the cost differences. Lastly, the gas system for PG&E is of sufficient capacity to make the area growth and capacity expansion a non-issue as well.

3.4.3 Gas Marginal Costs (Task A2.4)

Compile total marginal cost data on a seasonal basis, or other appropriate time of use basis, for production, transmission , distribution, storage, and customer service. Develop a 30-year forecast of these costs. Provide cost data from investor owned and municipal utilities as specified by the Commission Contract Manager,

Marginal cost data is included in the file Gas_data.xls for SCG and SDG&E on a system basis. Forecasts of marginal costs can also be found in the CBEE Appendices. PG&E staff mentioned prior attempts to segment the costs into time-based usage periods, but no satisfactory answer was reached in those efforts. Moreover, the PG&E staff person responsible for that research is currently on leave to the U.S. Military. PG&E has committed to providing the information it can gather in this area, but as of the date of this report, it has not yet been received.

Marginal Cost information is also shown in the following tables above:

- Table 28: PG&E Gas Marginal Costs
- Table 29: SoCalGas Marginal Costs
- Table 30: SDG&E Gas Transportation Marginal Costs
- Figure 29: SDG&E Procurement Costs

3.5 Marginal Costs for Propane (Task A3)

Marginal cost data for propane is not accessible to the public in any form that is differentiated from the marginal *prices*. The propane supply and distribution industry is made up of oil corporations and hosts of other private companies, not utilities. As such, these companies are not under the jurisdiction of the public utility commission, and therefore are not obligated to reveal total or unbundled costs for the purpose of setting rates or prices. Propane price information is provided later in this report as required in Task A6.

3.6 Task A4 - Marginal Prices for Electricity

3.6.1 Forecast Marginal Prices (Task A4.1)

Identify the range of likely generation, transmission, and distribution price structures for residential and nonresidential buildings after 2002.

The hourly or time of use “prices” that currently underlie IOU rates in California are based on marginal costs of generation, transmission, distribution, energy, and customer service. Of these components, generation capacity and energy have the largest influence on the shape of the costs. By shape we refer to the variation in costs by time of day and season. All TOU and RTP rates reflect the cost pattern of generation --- that is, high costs in the summer afternoon when generation excess capability is the lowest, and the most expensive generation units are brought into service.

With the restructuring of the industry, however, there is little impetus for utilities to maintain this same rate profile for the T&D portions of their rates. In other words, they should not charge for their service (T&D) based on someone else’s cost structure (generation). Generation and energy will be handled through the power exchange as an independent charge to customers. Delivery and transportation will be designed by the UDC, and it is likely that any TOU differentials currently embedded in the rates will be flattened once the rate freeze is lifted. Other possible future rate forms include a greater reliance on demand subscription or ratcheted demand charges for commercial customers, and fixed customer charges for smaller commercial and residential customers. When gas became deregulated in the late 1980’s, PG&E moved toward a ratcheted demand charge for non-core customers in order to gain revenue stability. Ultimately, however, PG&E moved back to volumetric based rates to satisfy customer desires. It is unclear how the rates may evolve in electricity. One potential change is a movement toward area rates that reflect both overall cost levels in an area, and also the timing of the peak usage in the area. For example, just as the generation problem led to summer afternoon peak periods in current rates, a particular area with a winter peaking problem could develop winter peaking rates. Currently area rates are not planned by any of the IOUs, but could develop in response to municipalization efforts and in conjunction with efforts to control T&D investments.

Another trend that we may see in post 2002 rates is a shift of the customer bill flat or TOU kWh usage charges to tiered energy, demand or customer charges. This shift has been discussed informally by many rate designers (both in California, and across North America) as a way to stabilize the UDC revenues. Their argument asserts that most UDC costs are unrelated to customer usage levels (other than losses and peak usage in constrained areas), so the revenue recovered from the customer should not vary greatly with usage. Loading the bulk of the revenues into a high tier 1 charge, ratcheted demand charges, demand subscription charges, or fixed customer charge, would allow customers to make more economically efficient marginal consumption decisions. (efficient with respect to the costs explicitly incorporated into the rate design) Note that the CPUC will be opening a formal proceeding to examine UDC rate design issues in the near future.

Unfortunately, such an evolution in the rates would likely reduce the incentives for customers to conserve energy, and would most likely ignore the environmental benefits of conservation (since emission costs would probably not be included explicitly in energy prices paid by consumers.

Provided below is another set of views on the direction of rate design in a restructured environment. The quote is from the *Restructuring plan for Massachusetts (1996)*.

> *In the rate design phase, the rates paid by retail customers ought to reflect marginal costs by function (unbundled marginal cost rates by function) to the extent possible consistent with the class revenue cap. Two-block rate designs could be used to accomplish this objective, where the initial-block reflects embedded costs and customer costs, and the tail-block reflects marginal costs. Rate designs could be derived directly from embedded and marginal cost information used to form class-specific retail revenue caps (customer and demand charges unbundled by function). However, specific customer class rate designs may be driven by constraints such as cost-effective metering capability. For example, small-use customers may still be charged on a customer and energy charge basis for transmission and distribution functions to the extent that time-of-use metering is not cost-effective. Thus, class rates designed to collect revenues up to the revenue cap must be reconciled to metered consumption on some reasonable basis.*
>
> *Individual customer class rate designs would be determined on a case-by-case basis and would be subject to Department approval. In determining appropriate rate designs, the Department must balance various pricing objectives including economic efficiency, rate continuity, fairness, Distribution Company earnings stability, and simplicity. We would anticipate that rates to Distribution Company customers would be primarily designed to recover allowable revenue requirements pursuant to the class revenue cap formulas.*
>
> *Customers within the same rate class should be charged similar rates for Distribution Company services. However, rate credits to consumers providing benefits to the Distribution Company (peak load management) should vary by local planning area depending on area-specific marginal T&D costs. Such rate credits should be used to provide the correct price signals to consumers or their competitive suppliers that are in a position to invest in distributed generation, load management or efficiency resources which the Distribution Company will seek in response to the incentive to cut the costs of Distribution Service*.

The Massachusetts plan illustrates the preference for moving toward rates that reflect marginal costs (the two-block rate), and that concentrate on Distribution company conditions and costs (local area rate credits). A clear vision of future rates in California will not be possible until after the CPUC completes its investigation into future rate forms, and the three California IOUs actually file testimony in this area.

3.6.2 TOU Price Patterns (Task A4.2)

Identify sources of data on actual and forecast residential and nonresidential time of use electricity price patterns.

For generation energy prices, please refer to section 3.3 on energy market price forecasts. For UDC prices, utility tariffs (available on-line at the respective utility web sites) will provide the most accurate estimate of price patterns. As for the way these prices will evolve over time, utility positions as expressed in their applications and rate proposals may provide an indication of the direction the utility wishes to take with its price structures. Major utility rate filings are typically on a three to six year schedule.

It is common in public utility ratemaking to phase-in large rate structure or level changes. Typically, the applicant will present its ultimate target, and then propose some measured movement toward that target. Through examination of the ultimate target, as well as intervenor positions against such a target, educated assumptions can be made regarding the evolution of the rate.

3.6.3 TOU Rates Currently in Use (Task A4.3)

Identify real time and time of use prices that are currently in effect in each utility service area (investor owned and municipal) in California. Organize by customer class.

Utility	PG&E	SCE	SDG&E	SMUD	LADWP	SVP
Response	Data derived from on-line tariffs	Data derived from on-line tariffs	Data from on-line tariffs and Filing with the CPUC re: Rate Unbundling	Not Provided	Not Provided	No TOU Information

The rates shown in the tables below are presented in three parts:

1. Total – The total rate seen by a bundled service ratepayer

2. Gen – The generation rate component of the rate. The generation rate recovers electricity payments through the PX, ISO charges, and CTC payments.

3. Net – The net rate is the rate received by the utility for its wires services. Wires services includes transmission, distribution, customer service and connection. This is equivalent to the payments to the UDC and / or third party retail service providers would receive in an unbundled competitive environment. Retail services include metering, billing, data management etc.

Note that for simplicity of presentation some rate modifiers have not been shown. Examples of information not included in the tables: minimum bill levels, rate limiters, baseline territories, power factor adjustments, and unbundled meter charges.

Table 34 : PG&E Residential TOU Rates

PG&E			Total	Gen	Net		Comment
E-1	Residential	Tier 1	0.11589	0.05952	0.05637	$/kWh	
		Tier 2	0.13321	0.06614	0.06707	$/kWh	
E-7	Residential	Smr Peak	0.31524	0.20378	0.11146	$/kWh	Peak is noon to 6pm M-F
		Smr Off	0.08515	0.04025	0.0449	$/kWh	Summer is May through October
		Wtr Peak	0.11636	0.06244	0.05392	$/kWh	Peak is noon to 6pm M-F except holidays
		Wtr Off	0.08851	0.04264	0.04587	$/kWh	
		Meter ($/day)	0.12813	0	0.12813	$/meter-day	
E-A7	Experimental TOU	Smr Peak	0.34733	0.23885	0.10848	$/kWh	Peak is 4pm to 8pm M-F
		Smr Off	0.08053	0.03966	0.04087	$/kWh	Summer is May through October
		Wtr Peak	0.11548	0.06574	0.04974	$/kWh	Peak is 4pm to 8pm M-F
		Wtr Off	0.0886	0.04568	0.04292	$/kWh	
		Meter ($/day)	0.12813	0	0.12813	$/meter-day	
E-8	Res Seasonal Option	Summer	0.12017	0.07104	0.04913	$/kWh	
		Winter	0.07308	0.03555	0.03753	$/kWh	
E-9	Optional TOU for Low Emission Vehicle Customers						

Table 35: PG&E Commercial TOU Rates

PG&E Commercial			Total	Gen	Net		Comment
A-1	Small Commercial	Summer	0.1487	0.08247	0.06623	$/kWh	
		Winter	0.10193	0.04958	0.05235	$/kWh	
		Cutomer Charge					
		Single Phase	8.1		8.1	$/kW-month	
		Poly Phase	12		12	$/kW-month	
A-6	Small Com TOU	Smr Peak	0.23258	0.1701	0.06248	$/kWh	12-6 M-F
		Partial	0.10288	0.06359	0.03929	$/kWh	8:30 to 9:30 excluding peak
		Off	0.05618	0.02524	0.03094	$/kWh	Off all others
		Wtr Ptl	0.11562	0.07405	0.04157	$/kWh	8:30 to 9:30pm (M-F, excluding Holidays)
		Wtr Off	0.07169	0.03798	0.03371	$/kWh	All Others
A-10	Medium						
	All Voltages	Smr	0.08915	0.06797	0.02118	$/kWh	
		Wtr	0.07279	0.05161	0.02118	$/kWh	
	Demand Charges ($/kW-mo)						
	Trans	Smr	1.95		1.95	$/kW-month	
		Wtr	0.45		0.45	$/kW-month	
	Primary	Smr	5.5		5.5	$/kW-month	
		Wtr	1.65		1.65	$/kW-month	
	Secondary	Smr	6.7		6.7	$/kW-month	
		Wtr	1.65		1.65	$/kW-month	
E-19	Peak Max Dmd	Smr	13.35		13.35	$/kW-month	
		Wtr	0		0	$/kW-month	
	Partial Max Dmd	Smr	3.7		3.7	$/kW-month	
		Wtr	3.65		3.65	$/kW-month	
	Max Demand	Smr	2.55		2.55	$/kW-month	
		Wtr	2.55		2.55	$/kW-month	
	Summer	Peak	0.08773	0.060692	0.027038	$/kWh	
		partial	0.0581	0.03342	0.02468	$/kWh	
		Off	0.05059	0.02645	0.02414	$/kWh	
	Winter	Partial	0.06392	0.03882	0.0251	$/kWh	
		Off	0.05038	0.02626	0.02412	$/kWh	

Table 36: PG&E Rate Descriptions

Utility	Rate Schedule	Customer Type	Description of Rate Form
PG&E	E-1 Residential	Individually metered single family dwellings and flats and apartments.	Inverted Block, with geographically determined baseline quantities determining the first tier. Baseline Quantities: Basic: Summer (kWh/day) 6.4 to 16.6; Winter 8.9 to 11.6 All Electric: Summer (kWh/day) 10.4 to 23.5; Winter 19 to 30.9
PG&E	E-7, E-A7 Residential TOU	Voluntary for E-1 customers	Meter Charge plus four TOU energy charges. Baseline credit also applied on a per kWh basis. EA-7 is an experimental rate for an alternate TOU peak period definition and rate.
PG&E	E-8 Residential Seasonal Service	Voluntary for customers under E-1 or E-7	Customer Charge plus seasonal energy rates
PG&E	E-9 Experimental LEV Residential	E-1 customers who refuel a low emissions vehicle at their premises	Four rate options with meter charges and TOU energy rates. Rate option varies based on LEV charging equipment features.
PG&E	A-1 Small Commercial	Not available to customers whose billing demand exceeds 499kW for three consecutive months	Seasonal energy charge, with customer charge that varies for single phase and poly-phase service.
PG&E	A-6 Small Commercial TOU	Voluntary TOU with same qualifications as A-1	Meter and customer charge plus five TOU period energy charge.
PG&E	A-10 Medium Commercial	Maximum demand less than 499kW for three consecutive months, and annual kWh exceeds 50,000	Meter and customer charge plus five TOU period energy charges. Charges vary by delivery voltage (Secondary, Primary, and Transmission)
PG&E	E-19 Medium General	Mandatory: Billing demand exceeded 499kW for three consecutive months, is not using 70% or more of energy for agricultural uses, and does not qualify for E-20. Voluntary for non agricultural customers with demand under 499kW	Meter and customer charge plus five TOU period energy charges, and partial peak and maximum demand charges.. Charges vary by delivery voltage (Secondary, Primary, and Transmission)

Table 37: SCE Residential TOU Rates

SCE Residential				Total	Gen	Net		Comments
Domestic		Summer	Baseline	0.12009	0.08778	0.03231	$/kWh	Summer is June to September
			NonBaseline	0.14157	0.1007	0.04087	$/kWh	
		Winter	Baseline	0.12009	0.044787	0.075303	$/kWh	
			NonBaseline	0.14157	0.06079	0.08078	$/kWh	
			Meter Charge	0.033	0	0.033	$/meter-day	Single-family residence
TOU-D-1		Summer	Basic Charge	0.033	0	0.033	$/meter-day	Summer is June through September
			TOU Meter Charge	0.08	0	0.08	$/meter-day	
			On-Peak	0.48583	0.42492	0.06091	$/kWh	10am to 6pm M-F, non-holiday
			Off-Peak	0.10367	0.04276	0.06091	$/kWh	All other hours
			Baseline Credit	0.02148	0.01292	0.00856	$/kWh	
		Winter	Basic Charge	0.033	0	0.033	$/meter-day	
			TOU Meter Charge	0.08	0	0.08	$/meter-day	
			On-Peak	0.14003	0.07912	0.06091	$/kWh	
			Off-Peak	0.09028	0.02937	0.06091	$/kWh	
			Baseline Credit	0.02148	0.01292	0.00856	$/kWh	
D-APS		Air Conditioner Cycling Program - discountinued.						
TOU-D-2		Summer	Customer Charge	0.26	0.14	0.12	$/day	Summer is June through September
			TOU Meter Charge	0.08	0	0.08	$/day	
			Peak	0.39527	0.33436	0.06091	$/kWh	10am to 6pm M-F, non-holidays
			Off-peak	0.08448	0.02357	0.06091	$/kWh	All other hours
		Winter	Customer Charge	0.26	0.14	0.12	$/day	
			TOU Meter Charge	0.08	0	0.08	$/day	
			Peak	0.11353	0.05262	0.06091	$/kWh	10am to 6pm M-F, non-holidays
			Off-peak	0.07326	0.01235	0.06091	$/kWh	All other hours

Table 38: SCE Commercial TOU Rates

General Service			Total	Gen	Net		Comments
GS-1		Customer Charge	0.48	0.2	0.28	$/day	
		Energy Charge	0.1176	0.06298	0.05462	$/kWh	
		Three phase charge	0.079	0	0.079	$/day	
GS-2	Summer	Customer Charge	60.3	12.24	48.06	$/month	
		Facilities Demand Charge	5.4	2.23	3.17	$/kW-mo	
		Time-related Demand	7.75	0	7.75	$/kW-mo	
		Energy Charge	0.07692	0.07036	0.00656	$/kWh for the first 300kWh per kW of Maximum Demand	
		Excess Charge	0.04391	0.03735	0.00656	$/kWh for all excess kWh	
	Winter	Customer Charge	60.3	12.24	48.06	$/month	
		Facilities Demand Charge	5.4	2.23	3.17	$/kW-mo	
		Time-related Demand	0	0	0	$/kW-mo	
		Energy Charge	0.07692	0.07036	0.00656	$/kWh for the first 300kWh per kW of Maximum Demand	
		Excess Charge	0.04391	0.03735	0.00656	$/kWh for all excess kWh	
TOU-GS-1	Summer	Customer Charge	0.48	0.2	0.28	$/day	Summer is June - September
		TOU Meter Charge	0.08	0	0.08	$/day	
		ON-Peak	0.5332	0.47858	0.05462	$/kWh	Noon to 6 M-F non-holiday
		Partial-Peak	0.08828	0.03366	0.05462	$/kWh	8am to Noon, 6pm to 11pm, M-F, non-holiday
		Off-Peak	0.05543	0.00081	0.05462	$/kWh	All other hours
	Winter	Customer Charge	0.48	0.2	0.28	$/day	
		TOU Meter Charge	0.08	0	0.08	$/day	
		ON-Peak	0	0	0		
		Partial-Peak	0.08131	0.02669	0.05462	$/kWh	8am to 11pm, M-F, non-holiday
		Off-Peak	0.05479	0.00017	0.05462	$/kWh	All other hours
TOU-GS-2		Customer Charge	79.25		79.25	$/month	
		Facilities Charge	5.4		5.4	$/kW-month	
	Summer						Summer is June through September
	Option A	On-Peak	7.75	0	7.75	$/kW-month	
		Mid-Peak	2.45	1.4	1.05	$/kW-month	
		Off-peak	0			$/kW-month	
	Option B	On-Peak	16.4	4.1	12.3	$/kW-month	
		Mid-Peak	2.45	1.4	1.05	$/kW-month	
		Off-peak	0			$/kW-month	
	Energy Charges						
	Option A	On-Peak	0.23201	0.17643	0.05558	$/kWh	Noon to 6pm
		Mid-Peak	0.06613	0.05857	0.00756	$/kWh	8am to Noon, 6pm to 11pm, M-F, non-holiday
		Off-peak	0.04271	0.03515	0.00756	$/kWh	All other hours
	Option B	On-Peak	0.14896	0.1414	0.00756	$/kWh	
		Mid-Peak	0.05613	0.05857	-0.00244	$/kWh	
		Off-peak	0.04271	0.03515	0.00756	$/kWh	
	Winter						
	Option A	On-Peak	0	0	0	$/kW-month	
		Mid-Peak	0	0	0	$/kW-month	
		Off-peak	0	0	0	$/kW-month	
	Option B	On-Peak	0	0	0	$/kW-month	
		Mid-Peak	0	0	0	$/kW-month	
		Off-peak	0	0	0	$/kW-month	
	Energy Charges						
	Option A	On-Peak	0			$/kWh	
		Mid-Peak	0.07811	0.07055	0.00756	$/kWh	
		Off-peak	0.04271	0.03515	0.00756	$/kWh	
	Option B	On-Peak	0			$/kWh	
		Mid-Peak	0.07811	0.07055	0.00756	$/kWh	
		Off-peak	0.04271	0.03515	0.00756	$/kWh	

Table 39: SCE RTP Rates

				Total	Gen	Net		
GS-2-RTP	Demand RTP		Customer Charge	60.3	12.24		$/month	
			Facility Demand Charge	5.4	2.23		$/kW-mo	
			Summer Demand Charge	14.35	0.96		$/kW-mo	Summer is June - September
			Winter Demand Charge	0			$/kW-mo	
		Energy Charge Adder						
			For First 300kWh per kW	0.07692	0.0704		$/kWh	
			All Excess	0.04391	0.03739		$/kWh	
		(Voltage discounts not shown)						
RTP-TPP-1	2-part RTP		Base period usage has the customers otherwise applicable rate applied					
			Usage in excess of the base has the following RTP rates:					
			Contribution to margin	0.01	0		$/kWh	
			CARE Surcharge	0.00079	0		$/kWh	
			PUC Reimbursement Fee	0.00012	0		$/kWh	
			Utility day-ahead forecast	Variable	80.36%		$/kWh	
RTP-2		Meter Charge						
			Up to 2kV	298.65	123.98		$/meter-mo	
			2kV to 50kV	299	124.11		$/meter-mo	
			above 50kV	349.45	145.06		$/meter-mo	
		Facilities demand charge						
			Up to 2kV	6.4	2.66		$/kW-mo	
			2kV to 50kV	6.6	2.73		$/kW-mo	
			above 50kV	0.65	0.26		$/kW-mo	
		Energy Charge						
			RTP-@ Hourly Rate	Variable	Varaible		$/kWh	

See http://www.sce.com/yourbill/rates/pdf/ce78-12.pdf for variable rate under RTP-2.

Table 40: SCE Rate Descriptions

Utility	Rate Schedule	Customer Type	Description of Rate Form
SCE	D Domestic	Single family accommodation, and domestic farm service	Inverted Block, with geographically determined baseline quantities determining the first tier. Baseline Quantities: Basic: Summer (kWh/day) 9.0 to 42.7; Winter 9.3 to 10.7 All Electric: Summer (kWh/day) 10.2 to 42.7; Winter 18.3 to 35.0
SCE	TOU-D-1 Time of Use Domestic	Voluntary for D customers	Meter Charge plus four TOU energy charges. Baseline credit also applied on a per kWh basis.
SCE	D-APS Domestic Automatic Powershift	Domestic with Central AC and portion of load that can be disconnected from Company service through Company automatic control devices.	Same as D, with $ per summer season day credits based on participation option chosen.
SCE	TOU-D-2 Time of Use Domestic	Voluntary for D customers	Meter and Customer Charge plus four TOU energy charges. Baseline credit also applied on a per kWh basis.
SCE	GS-1 General Service, Non-Demand	Maximum demand less than or equal to 20kW	Customer Charge and flat energy charge. Energy charges vary by delivery voltage level. 4.4% discount for 2kV to 50kV, and 12.8% for voltages over 50kV
SCE	GS-2 General Service, Demand	Maximum demand less than 500kW, and greater than 20kW	Customer charge, maximum demand charge with ratchet, and declining block energy rate. Size of the first tier is 300kWh per kW of maximum demand
SCE	TOU-GS-1 General Service TOU, non-demand	Maximum demand less than or equal to 20kW. Limited to 5000 new applicants per year and meter availability	Customer charge, meter charge, and five TOU period energy charge.
SCE	TOU-GS-2 General Service TOU, demand	Maximum demand less than 500kW, and greater than 20kW	Meter Charge, maximum demand charge (facility charge), peak and partial peak demand charges, and five TOU energy charges.
SCE	GS-2-RTP	GS-2 customers	Customer Charge, demand chare, and hourly energy charges
SCE	RTP-TPP-1	Maximum demand > 20kW. Expired with commencement of power exchange.	Not Applicable
SCE	RTP-2	Maximum demand in excess of 500kW	Customer Charge, demand chare, and hourly energy charges

Table 41: SDG&E Residential TOU Rates

SDG&E Domestic			Total	Gen	Net		Comments
DR		Baseline	0.10438	0.04313	0.06125	$/kWh	
		Non-Baseline	0.1247	0.05554	0.06916	$/kWh	
DR-TOU	Experimental TOU Rate	Meter Charge	3.4	0	3.4	$/meter-mo	Summer is May to October
	Summer	Peak	0.35648	0.29523	0.06125	$/kWh	Noon to 6pm M-F, non-holiday
		Off-peak	0.07949	0.01824	0.06125	$/kWh	All other
		Peak Baseline Credit	0.02032	0	0.02032	$/kWh	
		Off-peak Baseline Credit	0.02032	0	0.02032	$/kWh	
	Winter	Peak	0.1119	0.05085	0.06105	$/kWh	
		Off-peak	0.07949	0.0184	0.06109	$/kWh	
		Peak Baseline Credit	0.02032	0	0.02032	$/kWh	
		Off-peak Baseline Credit	0.02032	0	0.02032	$/kWh	

Table 42: SDG&E Commercial TOU Rates

SDG&E General Service			Total	Gen	Net		Comments
A		Basic Service Fee	7.77	0	7.77	$/month	
	Secondary Voltage	Energy Charge	0.11378	0.0531	0.06068	$/kWh	
	Primary Voltage	Energy Charge	0.11028	0.0531	0.05718	$/kWh	
A-V1	Secondary Voltage	Basic Service					
		0-500kW	43.5	0	43.5	$/meter-month	
		500.1-10,000kW	174.01	0	174.01	$/meter-month	
		>10,000kW	174.01	0	174.01	$/meter-month	
		Contact Closure Service	77.68	0	77.68	$/meter-month	
		Demand Charge					
		Non-Coincident	4.68	0.02	4.66	$/kW-mo	
		Contract mimimum	8.77	4.85	3.92	$/kW-mo	
		Power Factor	0.22	0	0.22	$/kVar	
		Energy Charge					
		Signaled Period	4.62955	3.35537	1.27418	$/kWh	Utility determined
		Semi-peak	0.06553	0.061	0.00453	$/kWh	6am to 10pm M-F, non-holiday
		Off-peak	0.03938	0.03485	0.00453	$/kWh	all other hours
	Primary, Substation, and Transmission not shown						
A-V2	Similar to A-V1, but additional, lower cost signal period added in exchage for a lower cost semi-peak period.						
A-TOU	Experimental TOU	Basic Service	7.77	0	7.77	$/meter-mo	
		Tou Meter Charge	3.4	0	3.4	$/meter-mo	Summer is May through September
	Summer	On-peak	0.33271	0.28391	0.0488	$/kWh	11am to 6pm, M-F non-holiday
		Semi-peak	0.05721	0.00841	0.0488	$/kWh	6am to 11am, 6pm to 10pm M-F. non-hliday
		Off-peak	0.05147	0.00157	0.0499	$/kWh	all others
	Winter	On-peak	0.19306	0.14326	0.0498	$/kWh	5pm to 8pm M-F, non-holiday
		Semi-peak	0.05721	0.00841	0.0488	$/kWh	6am to 5pm, 8pm to 10pm, M-F non-holiday
		Off-peak	0.05147	0.00157	0.0499	$/kWh	All others
Total Rates from SDG&E on-line tariffs.							
Generation Rates from CPUC Direst Access Working Group Web Site. Http://162.15.5.2/wk-group/attach-h.doc, SDG&E Filing with with CPUC							

Table 43: SDG&E Rate Descriptions

Rate Schedule	Customer Type	Description of Rate Form
DR Domestic Service	Individually metered single family dwellings and flats and apartments.	Inverted Block, with geographically determined baseline quantities determining the first tier. Baseline Quantities: Basic: Summer (kWh/day) 8.3 to 11.4; Winter 8.3 to 9.9 All Electric: Summer (kWh/day) 9.8 to 19.5; Winter 16.6 to 26.5
DR-TOU Experimental	Voluntary for DR customers	Meter Charge plus four TOU energy charges. Baseline credit also applied on a per kWh basis.

Rate Schedule	Customer Type	Description of Rate Form
Domestic TOU		
A General Service	Maximum demand less than 20kW and monthly usage less than 12,000 kWh for 12 months.	Basic service fee, and flat energy charge (varies by delivery voltage level)
A-V1 General Service Variable TOU	All non-residential metered customers	Basic service fee, contract closure fee, non-coincident and contract minimum demand charge, power factor charge, and three TOU energy charges (including a signal period)
A-V2 General Service Variable TOU 2	All non-residential metered customers	Basic service fee, contract closure fee, non-coincident and contract minimum demand charge, power factor charge, and four TOU energy charges (including a signal period)
A-TOU Experimental TOU, Small time metered	Maximum Demand less than 40kW	Basic service charge, meter charge, and four TOU energy charges.

3.6.4 TOU Price Basis (Task A4.4)

Determine the hourly or time of use "prices" that underlie "blended" rates for each customer class (residential, small commercial)

Utility	PG&E	SCE	SDG&E	SMUD	LADWP	SVP
Response	Based on marginal costs provided in PG&E's 1996 GRC Proceeding.	Not Provided. Derived from public documents	Not Provided	Not Provided	Current LADWP staff does not know the basis for their TOU rates.	Not Calculated by SVP

Table 44: PG&E Marginal Costs ($/kWh) from 1996 General Rate Case

	SUMON	SUMPT	SUMOF	WINPT	WINOF
Residential (E-1,E-7, E-8)					
Generation Capacity	0.0636				
Energy	0.0268	0.0204	0.0179	0.0252	0.0211
Transmission	0.0069	0.0024	0.0004	0.0022	0.0003
Distribution	0.0678	0.0229	0.0038	0.0255	0.0044
Customer	0.0106	0.0106	0.0106	0.0106	0.0106
Total	0.1757	0.0562	0.0325	0.0634	0.0364
Small Commercial (A-1,A-6)					

	SUMON	SUMPT	SUMOF	WINPT	WINOF
Generation Capacity	0.0502				
Energy	0.0268	0.0204	0.0179	0.0252	0.0211
Transmission	0.0070	0.0022	0.0002	0.0018	0.0002
Distribution	0.0590	0.0180	0.0019	0.0179	0.0032
Customer	0.0129	0.0129	0.0129	0.0129	0.0129
Total	0.1559	0.0534	0.0328	0.0578	0.0374

Table 45: Southern California Edison Total Marginal Costs by TOU Period (1998 $/kWh)

	Summer			Winter	
	On	Partial	Off	Partial	Off
Domestic	0.2483	0.0568	0.0417	0.0547	0.0414
GS-1	0.1970	0.0601	0.0459	0.0568	0.0456
GS-2	0.1554	0.0427	0.0316	0.0414	0.0313

Information was not provided directly by SCE. The above table was derived from information filed with the CPUC as part of Edison's unbundled ratemaking proceeding. (Workpapers in Support of A.96-12-019, Exhibit SCE-1 – Prepared Testimony, Chapter IV and Appendix B) This information will be available in future General Rate Case Proceedings before the CPUC. The CEC should become an active participant in these cases to guarantee receipt of the detailed workpapers in the future. Unlike testimony, the supporting workpapers are not kept by the CPUC official files room, and there is no guarantee of utilities being able to produce (or being willing to produce) copies of the workpapers once the proceeding is closed.

The original source of the information can be found in SCE's 1992 General Rate case (see D. 92-06-020). The SCE workpapers express marginal capacity costs in terms of coincident-related costs and non-coincident-related costs. For development of the differentiated marginal costs, we have assigned 100% of the coincident costs to the summer on-peak period, and have spread the noncoincident costs (including marginal customer costs) uniformly to all hours of the year. The assignment of all coincident costs to the summer period was based on SCE's Coincidence conversion factors. The conversion factors are similar to PG&E's PCAF allocation factors.

Table 46: Detailed Derivation of the SCE marginal costs by TOU period:

SCE							Unit Costs:	Transmission	Distribution		
							Coincident	39.91	14.28		
							NonCoincident	4.43	30.35		
All Costs and Revenues in Thousands							% Coincident:	90%	32%		
		Summer			Winter						
		On	Partial	Off	Partial	Off		Transmission	Distributior	Customer	Total
MEC Rev $k	Domestic	52178	52167	73375	136240	149467		290840	482663	156868	1393798
	GS-1	12226	9455	10506	32499	22365		44332	93713	41934	267030
	GS-2	50913	43949	51564	140385	100870		175912	236967	59109	859669
Coincident Capacity Cost	Domestic							261782.2373	154434.9		416217.1
	GS-1							39902.79928	29984.8		69887.6
	GS-2							158336.6694	75820.94		234157.6
Noncoincident Costs	Domestic							29057.76274	328228.1	156868	514153.9
	GS-1							4429.200722	63728.2	41934	110091.4
	GS-2							17575.33063	161146.1	59109	237830.4
MWh	Domestic	1775401	2437135	3997278	5595696	8261989					22067499
	GS-1	416020	442200	572339	1334857	1236282					4001698
	GS-2	1732849	2055754	2809868	5767523	5577306					17943300
Energy Costs	Domestic	0.029389	0.021405	0.018356	0.024347	0.018091					
($/kWh)	GS-1	0.029388	0.021382	0.018356	0.024346	0.018091					
	GS-2	0.029381	0.021379	0.018351	0.024341	0.018086					
Coincidence conversion Fctr:		0.83426	0.07095	0	0.09479		(Workpapers, Appendix B page 27)				
Coincident Capacity Cost	Domestic	0.19558	0.012117	0	0.007051	0					
($/kWh)	GS-1	0.140148	0.011213	0	0.004963	0					
	GS-2	0.112732	0.008081	0	0.003848	0					
											Average
Noncoincident Costs	Domestic	0.023299	0.023299	0.023299	0.023299	0.023299					0.023299
($/kWh)	GS-1	0.027511	0.027511	0.027511	0.027511	0.027511					0.027511
	GS-2	0.013255	0.013255	0.013255	0.013255	0.013255					0.013255
			Summer		Winter						
		On	Partial	Off	Partial	Off					
Total Marginal Cost by TOU	Domestic	0.2483	0.0568	0.0417	0.0547	0.0414					
($/kWh)	GS-1	0.1970	0.0601	0.0459	0.0568	0.0456					
	GS-2	0.1554	0.0427	0.0316	0.0414	0.0313					
Workpaper - Southern California Edison / Application 96-12-019, Exhibit No SCE-1, Appendix B, p. 117											
Transmission and Distribution Costs : pages 12 and 13.											
Allocate Coincident costs to periods using the Coincidence Conversion Factors											
Average non-coincident costs over all hours with uniform probability.											

The uppermost section of the sheet contains the marginal cost of capacity for transmission and distribution. The capacity costs are split between coincident and non-coincident, according to SCE's workpapers. The next section shows the total marginal cost revenues for the Domestic, GS-1, and GS-2 classes. Energy costs are shown by TOU period, followed by transmission costs, distribution costs, and customer costs.

The sheet then allocates the transmission and distribution costs between coincident and non-coincident (see sections labeled "Coincident Capacity Cost", and "Noncoincident Costs"), based on the splits shown in the fourth row.

MWh shows the total energy by TOU period for each of the three customer groups.

Energy Costs simple divides the marginal energy cost revenues by the sales to derive a $/kWh value.

Coincidence conversion factor provides a means to allocate the coincident costs to TOU periods. Note that the factors sum to 1.0.

Coincident Capacity Cost takes the total coincident capacity costs (both T&D) for each customer group, and multiplies it by the Coincidence conversion factor, then divides by the MWh to develop $/kWh costs by TOU period

Noncoincident Costs are spread equally to all kWh consumed, so there is no variation by TOU period.

Total Marginal Cost by TOU is the sum of energy, coincident capacity, and noncoincident capacity costs.

3.6.5 Marginal Price Forecast (Task A4.5)

Develop a 30-year forecast of the prices of electricity after 2002. The forecast will capture variations in hourly costs, by time of use, seasons, customer class, and regional planning area.

The marginal price of electricity is the cost to the customer of their last unit of consumption. Depending on the rate schedule, the unit of consumption may be monthly usage, hourly usage, or usage at the time of the customer's peak usage in a month. Examples are shown below:

Rate Schedule Form	Marginal Price
Single energy rate	same as average price
Energy and customer charge	Energy charge only
Two tier energy charge	Second tier energy charge
Energy and demand charge	Includes both energy charge, and demand change. If the change in usage occurs at the time of the customer's peak usage, then demand cost is a part of the marginal price.

Electric utilities are currently in the midst of restructuring their class revenue allocations and rate designs to respond to changes in market structure. As mentioned above, the current rates are based on the total marginal cost of providing electricity (including generation capacity and energy). With the removal of generation from the UDC's purview, the remaining rates are unlikely to have much resemblance to the current rates. In the near term, utilities may leave rates similar to current rates for reasons of rate stability and minimizing bill impacts, but the eventual evolution of the rates may take them away from current levels and designs.

There may be some stability in near term rate levels, but there is little expectation for marginal prices to resemble current levels once the rate freeze is lifted. Discussions with PG&E indicated that any projection of marginal prices on their part would be unsuitable for any policy decision making at this time. PG&E acknowledges that marginal prices are more appropriate for determining impacts on customers from changes in building energy usage, but there is too much uncertainty, and too many issues to be resolved in the upcoming rate proceedings. Their recommendation is to use average rate levels for any analysis prior to a resolution of UDC rate design issues in the upcoming CPUC investigation.

For completeness, however, the marginal prices have been provided in the tables below.

Data for one year:

Utility	PG&E	SCE	SDG&E	SMUD	LADWP	SVP
Response	Marginal Prices from Tariffs. Average Rate Information provided	Marginal prices based on-line tariffs	Marginal prices based on-line tariffs	Marginal rate and average rate provided for 1998	Annual average (bundled rates)	Tier Rates and average rates provided

Table 47: PG&E Marginal Prices

			Total	Gen	Net	
Residential			Total	Gen	Net	
E-1		Tier 2	0.13321	0.06614	0.06707	$/kWh
Commercial						
A-1		Summer	0.1487	0.08247	0.06623	$/kWh
		Winter	0.10193	0.04958	0.05235	$/kWh
A-10		Summer	0.08915	0.06797	0.02118	$/kWh
		Winter	0.07279	0.05161	0.02118	$/kWh

Note: For TOU rates, see the energy charges for PG&E rate schedules shown in Table 34 *and* Table 35.. *No Geographic information (other than baseline quantities) is available from public documents.*

Table 48: PG&E Average Prices for Residential Customers ($/kWh)

Average Price is the total of customer bills for the month divided by the monthly consumption. The average price includes generation energy and capacity payments. The "_1" to "_12" identifier refers to the months January to December respectively.

DIV	CLASS	AvgRate_1	AvgRate_2	AvgRate_3	AvgRate_4	AvgRate_5	AvgRate_6	AvgRate_7	AvgRate_8	AvgRate_9	AvgRate_10	AvgRate_11	AvgRate_12
Central Coast	RES-B	0.124	0.124	0.124	0.123	0.125	0.125	0.125	0.125	0.125	0.125	0.124	0.125
Central Coast	RES-H	0.117	0.117	0.116	0.117	0.125	0.127	0.126	0.126	0.126	0.125	0.120	0.119
De Anza	RES-B	0.123	0.123	0.122	0.123	0.125	0.126	0.126	0.126	0.125	0.125	0.124	0.124
De Anza	RES-H	0.119	0.118	0.117	0.118	0.122	0.123	0.123	0.123	0.123	0.122	0.120	0.121
Diablo	RES-B	0.123	0.123	0.123	0.123	0.125	0.128	0.128	0.127	0.126	0.125	0.124	0.124
Diablo	RES-H	0.119	0.119	0.118	0.118	0.122	0.124	0.124	0.124	0.123	0.122	0.120	0.121
East Bay	RES-B	0.123	0.123	0.123	0.123	0.124	0.125	0.124	0.124	0.124	0.124	0.123	0.124
East Bay	RES-H	0.119	0.119	0.117	0.118	0.120	0.120	0.120	0.120	0.120	0.120	0.119	0.120
Fresno	RES-B	0.121	0.121	0.120	0.120	0.122	0.125	0.125	0.125	0.123	0.121	0.121	0.122
Fresno	RES-H	0.116	0.115	0.114	0.116	0.122	0.125	0.125	0.124	0.123	0.120	0.117	0.117
Kern	RES-B	0.122	0.122	0.122	0.121	0.122	0.125	0.126	0.125	0.124	0.121	0.122	0.123
Kern	RES-H	0.118	0.117	0.116	0.117	0.122	0.125	0.126	0.125	0.124	0.121	0.118	0.119
Los Padres	RES-B	0.123	0.123	0.122	0.122	0.124	0.124	0.124	0.124	0.124	0.123	0.123	0.123
Los Padres	RES-H	0.116	0.116	0.115	0.116	0.124	0.126	0.126	0.126	0.126	0.124	0.118	0.118
Mission	RES-B	0.123	0.123	0.123	0.123	0.125	0.126	0.125	0.125	0.125	0.124	0.124	0.124
Mission	RES-H	0.119	0.119	0.118	0.118	0.121	0.122	0.122	0.122	0.122	0.121	0.119	0.120
North Bay	RES-B	0.123	0.122	0.121	0.122	0.125	0.126	0.125	0.125	0.124	0.124	0.123	0.123
North Bay	RES-H	0.117	0.116	0.114	0.117	0.124	0.126	0.125	0.125	0.125	0.122	0.118	0.119
North Coast	RES-B	0.122	0.122	0.121	0.121	0.123	0.124	0.123	0.123	0.123	0.123	0.122	0.123
North Coast	RES-H	0.115	0.114	0.113	0.114	0.123	0.124	0.124	0.124	0.123	0.122	0.117	0.117
North Valley	RES-B	0.121	0.121	0.120	0.120	0.120	0.123	0.124	0.123	0.121	0.120	0.121	0.121
North Valley	RES-H	0.114	0.113	0.113	0.113	0.121	0.123	0.124	0.123	0.122	0.120	0.115	0.115
Peninsula	RES-B	0.124	0.124	0.123	0.123	0.126	0.126	0.126	0.125	0.126	0.125	0.124	0.124

DIV	CLASS	AvgRate_1	AvgRate_2	AvgRate_3	AvgRate_4	AvgRate_5	AvgRate_6	AvgRate_7	AvgRate_8	AvgRate_9	AvgRate_10	AvgRate_11	AvgRate_12
Peninsula	RES-H	0.120	0.119	0.118	0.118	0.122	0.123	0.123	0.123	0.123	0.122	0.118	0.119
Sacramento	RES-B	0.123	0.123	0.122	0.122	0.123	0.126	0.126	0.125	0.124	0.122	0.123	0.124
Sacramento	RES-H	0.117	0.116	0.115	0.116	0.122	0.125	0.125	0.125	0.124	0.122	0.117	0.118
San Francisco	RES-B	0.124	0.124	0.123	0.123	0.125	0.125	0.124	0.124	0.125	0.124	0.123	0.123
San Francisco	RES-H	0.120	0.120	0.119	0.118	0.120	0.120	0.120	0.120	0.120	0.120	0.119	0.121
San Jose	RES-B	0.123	0.123	0.122	0.123	0.124	0.125	0.125	0.125	0.124	0.124	0.123	0.124
San Jose	RES-H	0.118	0.118	0.117	0.117	0.122	0.123	0.123	0.123	0.123	0.122	0.119	0.120
Sierra	RES-B	0.123	0.123	0.122	0.122	0.122	0.126	0.126	0.125	0.124	0.122	0.123	0.123
Sierra	RES-H	0.117	0.116	0.114	0.115	0.123	0.125	0.125	0.125	0.124	0.122	0.117	0.117
Stockton	RES-B	0.123	0.123	0.122	0.122	0.122	0.125	0.125	0.125	0.123	0.122	0.122	0.123
Stockton	RES-H	0.115	0.114	0.113	0.114	0.122	0.124	0.124	0.123	0.122	0.120	0.116	0.116
Yosemite	RES-B	0.122	0.122	0.121	0.121	0.121	0.124	0.125	0.124	0.123	0.121	0.122	0.123
Yosemite	RES-H	0.115	0.115	0.113	0.115	0.122	0.124	0.124	0.124	0.123	0.120	0.116	0.116

RES-B is a basic service residential customer. Res H is an electric heating customer. The electric heating customers receive a higher baseline allowance.

Table 49: PG&E Average Small Commercial Rates ($/kWh)

Average Price is the total of customer bills for the month divided by the monthly consumption. The average price includes generation energy and capacity payments. The "_1" to "_12" identifier refers to the months January to December respectively.

DIV	AvgRate_1	AvgRate_2	AvgRate_3	AvgRate_4	AvgRate_5	AvgRate_6	AvgRate_7	AvgRate_8	AvgRate_9	AvgRate_10	AvgRate_11	AvgRate_12
Central Coast	0.1241	0.1240	0.1241	0.1286	0.1504	0.1536	0.1568	0.1590	0.1587	0.1536	0.1210	0.1154
De Anza	0.1230	0.1231	0.1232	0.1285	0.1504	0.1529	0.1579	0.1601	0.1601	0.1521	0.1181	0.1144
Diablo	0.1246	0.1246	0.1243	0.1289	0.1494	0.1516	0.1546	0.1573	0.1575	0.1522	0.1195	0.1151
East Bay	0.1235	0.1232	0.1231	0.1280	0.1501	0.1530	0.1568	0.1592	0.1593	0.1527	0.1201	0.1154
Fresno	0.1249	0.1247	0.1245	0.1296	0.1505	0.1525	0.1562	0.1589	0.1591	0.1528	0.1218	0.1169

DIV	AvgRate_1	AvgRate_2	AvgRate_3	AvgRate_4	AvgRate_5	AvgRate_6	AvgRate_7	AvgRate_8	AvgRate_9	AvgRate_10	AvgRate_11	AvgRate_12
Kern	0.1223	0.1218	0.1217	0.1268	0.1484	0.1503	0.1531	0.1559	0.1562	0.1493	0.1189	0.1165
Los Padres	0.1247	0.1241	0.1230	0.1277	0.1490	0.1520	0.1553	0.1563	0.1566	0.1509	0.1207	0.1161
Mission	0.1217	0.1216	0.1220	0.1283	0.1489	0.1517	0.1572	0.1595	0.1597	0.1513	0.1196	0.1143
North Bay	0.1245	0.1246	0.1248	0.1318	0.1520	0.1536	0.1585	0.1601	0.1606	0.1521	0.1193	0.1156
North Coast	0.1219	0.1214	0.1214	0.1271	0.1519	0.1539	0.1569	0.1580	0.1583	0.1528	0.1201	0.1159
North Valley	0.1253	0.1252	0.1253	0.1309	0.1525	0.1537	0.1564	0.1595	0.1583	0.1530	0.1213	0.1173
Peninsula	0.1228	0.1228	0.1227	0.1276	0.1503	0.1521	0.1568	0.1587	0.1587	0.1528	0.1181	0.1144
Sacramento	0.1239	0.1239	0.1242	0.1309	0.1503	0.1533	0.1580	0.1596	0.1588	0.1481	0.1207	0.1158
San Francisco	0.1242	0.1239	0.1239	0.1322	0.1506	0.1536	0.1585	0.1602	0.1600	0.1479	0.1194	0.1151
San Jose	0.1234	0.1229	0.1226	0.1288	0.1497	0.1523	0.1560	0.1569	0.1569	0.1495	0.1180	0.1141
Sierra	0.1247	0.1249	0.1248	0.1307	0.1535	0.1546	0.1578	0.1618	0.1600	0.1544	0.1193	0.1161
Stockton	0.1264	0.1267	0.1270	0.1320	0.1526	0.1545	0.1589	0.1617	0.1621	0.1555	0.1224	0.1169
Yosemite	0.1277	0.1272	0.1274	0.1325	0.1527	0.1541	0.1582	0.1606	0.1605	0.1544	0.1218	0.1175

Table 50 : SCE Marginal Prices

Marginal Prices		Season	Charge	Total	Gen	Net		Comment
Domestic		Summer	Non Baseline	0.14157	0.1007	0.04087	$/kWh	Summer is June to September
		Winter	Non Baseline	0.14157	0.06079	0.08078	$/kWh	
General Service								
GS-1			Energy Charge	0.1176	0.06298	0.05462	$/kWh	
GS-2		Summer	Excess Charge	0.04391	0.03735	0.00656	$/kWh	
		Winter	Excess Charge	0.04391	0.03735	0.00656	$/kWh	

Note: For TOU rates, see the energy charges for SCE rate schedules shown in Table 37 and Table 38. No Geographic information (other than baseline quantities) is available from public documents.

Table 51: SDG&E Marginal Prices

Residential			Total	Gen	Net		Comments
DR		Non-Baseline	0.1247	0.05554	0.06916	$/kWh	
DR-TOU	Summer	Peak	0.35648	0.29523	0.06125	$/kWh	Noon to 6pm M-F, non-holiday
		Off-peak	0.07949	0.01824	0.06125	$/kWh	All other
	Winter	Peak	0.1119	0.05085	0.06105	$/kWh	
		Off-peak	0.07949	0.0184	0.06109	$/kWh	
General Service							
A		Energy Charge	0.11378	0.0531	0.06068	$/kWh	

No geographic information (other than baseline quantity differences) is available from public documents.

Table 52: SMUD Bundled Marginal Rates (1998 $/kWh) Note that SMUD's rates are bundled service. Bundled service includes generation capacity and energy. This corresponds to the "Total" marginal price shown for **Table 47**, **Table 50**, and **Table 51**.

Rate Group	Season	Marginal Energy Rate	% Customers that Experience Rate
Residential Standard	Summer	$ 0.1270	62%
	Winter	$ 0.1181	60%
Residential Electric Heat	Summer	$ 0.1270	64%
	Winter	$ 0.1181	56%
Small Commercial	Summer	$ 0.0804	100%
	Winter	$ 0.0727	100%
Medium Commercial	Summer	$ 0.0565	74%
	Winter	$ 0.0561	75%

Table 53: SMUD Bundled Average Rates (1998 $/kWh)

Class ($/kWh)	1998
Res Electric Space Heat	$ 0.0783
Res Non-Electric Space Heat	$ 0.0898
Small Commercial	$ 0.0788

LADWP Average annual rates (cents/kWh) (12 month period ending July 1998)

Residential	10.28
Commercial	9.51
Industrial	8.15

Information was not available for T&D versus generation rates for LADWP.

Table 54: Silicon Valley Power Prices

D-1 (Residential)	Total	Gen	Net		Comment
Customer Charge	2.17	0.6076	1.5624	$/meter-mo	
Tier 1 Energy	0.06456	0.018077	0.046483	$/kWh	First 300kWh
Tier 2 Energy	0.07458	0.020882	0.053698	$/kWh	<-- Use for Marginal Rate
Class Average	*0.072*	*0.02016*	*0.05184*	*$/kWh*	*<-- Use for Average rate*
C-1 (Commercial)					
Customer Charge	2.34	1.78776	0.55224	$/meter-mo	
Tier 1 Energy	0.11141	0.085117	0.026293	$/kWh	First 800kWh
Tier 2 Energy	0.10100	0.077164	0.023836	$/kWh	<-- Use for Marginal Rate
Class Average	*0.105*	*0.08022*	*0.02478*	*$/kWh*	*<-- Use for Average rate*
Split of Gen and Net based on Pseudo Unbundled components by class provided by SVP.					

We are currently working on adding projections for rates, which will be added here. PBR escalation factors will be used to project T&D rates, which will be combined with the forecast of generation market prices.

3.7 Marginal Prices for Natural Gas (Task A5)

3.7.1 Future Price Structures (Task A5.1)

Identify the range of likely production, transmission, storage, distribution and customer service price structures for residential and nonresidential buildings.

Current price structures are described below. E3 believes that price structures for residential and nonresidential buildings will continue to follow the current practice of pricing gas commodity at a monthly price. According to CPUC staff, Southern California Gas would prefer to eliminate the usage of baselines for usage levels and instead would prefer to have declining block rate structures. However, according to CPUC staff it would require legislation to remove the baseline and tier rate structures currently in place. It seems likely that the remaining (non-commodity) services will continue to be tariffed at a flat rate that changes on an annual or seasonal basis and is subject to seasonally and/or geographically differentiated baseline usage levels.

Utility	Rate Class	Customer Type	Description of Rate Form
PG&E	G-1: Residential Service	Individually metered single family residences	Customers are billed two charges: 1. Procurement 2. Transportation Both charges have a rate for baseline usage and a rate for excess usage. The procurement rates include a gas commodity charge (GCP) that varies monthly. Baseline consumption is seasonally (S,W) and regionally differentiated
PG&E	G-NR1: Small Commercial	Non-residential core customers, with average monthly usage under 20,800 therms	Customers pay three charges: 1. Customer Charge 2. Procurement Charge 3. Transportation Charge Customer charge is a fixed monthly charge. The procurement rates include a gas commodity charge (GCP) that varies monthly. Procurement and transportation charges are seasonally differentiated (S,W)
SDG&E	GR: Domestic	Individually metered residential customers	Customers pay one charge: 1. Commodity Charge Commodity charge has two rates, one for baseline consumption and one for excess consumption. The commodity rates include a gas commodity charge (GCP) that varies monthly. Baseline usage levels are seasonally (S, W) (not geographically) differentiated.
SDG&E	GN-1: Commercial and Industrial	Non residential where average monthly usage is less than 20,080 therms	Customers pay two charges: 1. Customer Charge 2. Commodity Charge Customer charge is a fixed monthly charge. The commodity rates include a gas commodity charge (GCP) that varies monthly. The fixed (non-GCP portion) of the Commodity charge is seasonally differentiated (S, W). Commodity charge is two-tier, one rate applying to the first 1000 therms of usage, and a second rate applying to usage over 1000 therms.
SCG	GR: Residential	Individually metered residential customers	Customers pay two charges: 1. Customer Charge 2. Commodity Charge (four components) i. procurement charge ii. transmission charge iii. San Juan lateral interstate demand charge iv. procurement carrying cost of storage inventory charge Customer charge is a fixed monthly charge. This charge is constant throughout the year for customers who are not "space heating only" customers. "Space heating only" customers pay a higher customer charge in winter, and no charge during the summer, unless usage exceeds 20 therms/month. Procurement charge varies monthly. Transmission charge has two rates: one for baseline consumption and one for consumption above baseline Baseline usage is seasonally (S,W) and geographically (climate zones 1,2, and 3) differentiated. For multi-family, individually metered dwellings, baseline usage rates are differentiated by customer type, season (residences with no space heating are not seasonally differentiated), and climate zone.
SCG	GN-10:	Core customers	Customer pays two charges:

Utility	Rate Class	Customer Type	Description of Rate Form
	small commercial and industrial	with usage not exceeding 200,000 therms per year (or 20,080 therms/month)	1. Customer charge 2. Commodity charge (four components) i. Procurement charge ii. transmission charge iii. San Juan lateral interstate demand charge iv. Procurement carrying cost of storage inventory charge Customer charge is a fixed monthly charge. This charge is constant throughout the year for customers who are not “space heating only” customers. “Space heating only” customers pay a higher customer charge in winter, and no charge during the summer, unless usage exceeds 20 therms/month. Procurement charge varies monthly. Transmission charge is broken into three tiers: 1. first 100 therms of summer usage and first 250 therms of winter usage 2. usage above tier 1 up to 4167 therms/month 3. all usage above 4167 therms/month

3.7.2 Data Sources (Task A5.2)

Identify sources of data on actual and forecast residential and nonresidential seasonal natural gas price patterns.

Actual Prices: PG&E, SDG&E and SCG gas rates for core customers include a gas commodity price that varies on a monthly basis. Each of the utilities files its monthly rate sheet with the update monthly gas prices with CPUC. Seasonal changes in the gas price can be tracked through these monthly rate filings. Gas_data.xls contains historical gas commodity prices for each utility (see utility price sheets).

Forecast Prices: SCG provided its *1998 California Gas Report Workpapers* which contains historical and forecasted prices for SCG customer segments. Pages 99-103 show annual average gas rates from 1980 – 2015 for single family, multi-family <= 4 units, multi-family >4 units, master metered and sub-metered customers. *Appendix K: Marginal Rates*, provides system average marginal rates, by month, for 14 different commercial customer types under 250,000 therm annual consumption, from 1980 through 2019.

3.7.3 Average versus Marginal Prices (Task A5.3)

Identify average natural gas prices and reasons why there would be differences between average and marginal prices and provide written description.

Average natural gas prices will not equal marginal natural gas prices because of the use of baseline consumption levels in rate design and the use of declining block and seasonal pricing. Utilities typically designate baseline consumption levels for residential customers. For any consumption up to the baseline level, the customer pays the same total monthly charge, so the marginal cost of increased consumption up to the baseline level is zero, where as the average cost depends on the total amount they consume (average cost = fixed price/consumption). For commercial customers, average and marginal rates differ because of block and seasonal pricing. Average costs reflect the prices paid for all blocks of consumption, while marginal prices reflect the price paid for consumption in the last block. For example, a customer will pay 0.20 $/therm for the first 100 therms, and 0.10 $/therm for all consumption above 100 therms. If the customer consumes 150 therms, the marginal cost to the customer is 0.10 $/therm, while the average cost is (100 x 0.20 + 50 x 0.10)/150 = 0.167 $/therm. Seasonal variations have the same effect.

PG&E Class Average Rates

Class	($/th)
Residential	0.600417
Small Commercial	0.61813

CPUC Decision 98-06-073, 1998 BCAP June 18, 1998

Rates include average backbone transmission, local transmission, distribution, storage, customer class charge and procurement charges.

SCG Class Average Rates

Class	($/th)
Residential	0.68935
Small Commercial	0.56085

Decision 97-04-082, Appendix B

SDG&E Class Average Rates

Class	($/th)
Residential	0.64487
Small Commercial	0.62495

Decision 97-04-082, Appendix C

3.7.4 Unbundled Prices (Task A5.4)

Obtain publicly available data on natural gas prices for production, transmission, distribution, storage, customer-related new construction and customer service.

The CPUC's Biennial Cost Allocation Proceeding filings provide gas rates by customer class. PG&E is the only utility that has filed fully unbundled rate data. See Gas_data.xls for utility price data, including unbundled natural gas prices. Rate data for SCG and SDG&E is in the utilities' tariff sheets.

PG&E's rates are listed below. The rates for PG&E are taken from PG&E's 1998 BCAP decision and reflect PG&E's core gas rates were set by the Gas Accord beginning March 1, 1998..

Table 55: 1998 PG&E Gas Accord Average Rate Components ($/Dth) (Effective March 1, 1998)

Rate Component	Residential	Small Commercial	Large Commercial
Intrastate Backbone Transmission	0.1244	0.1244	0.0665
Intrastate Local Transmission	0.2602	0.2602	0.2602
Customer Class Charge	0.6315	0.6835	0.7699
Customer Access Charge/Customer Charge	0.000	0.5010	0.0447
Distribution	2.7041	2.2031	0.7975
Storage, Bundled	0.1311	0.1311	0.1006
Procurement, less Intra and Interstate PLD	2.0105	2.0105	1.9542
Interstate Pipeline Demand Charge	0.1585	0.1565	0.1113

(CPUC Decision 98-06-073 June 18, 1998, Application of Pacific Gas and Electric Company for authority to adjust its gas rates and tariffs to be effective January 1, 1998, pursuant to Decision Nos. 89-01-040, 90-09-089, 91-05-029, 93-12-058, 94-07-024, and 95-12-053, Appendix B, Table 8.)

Table 56 : PG&E Gas Accord Core Present Value ($1997) Rates ($/Therm) (excludes commodity charge) (3% Discount Rate)

	1997	1998	1999	2000	2001	2002
Residential						
Backbone	0.0149	0.0157	0.0164	0.0167	0.0169	0.0171
Local Transmission	0.0254	0.0260	0.0267	0.0273	0.0280	0.0287
Customer Class Charge	0.0353	0.0224	0.0223	0.0121	0.0120	0.0119
Distribution	0.2533	0.2533	0.2596	0.2661	0.2728	0.2796
Storage	0.0113	0.0118	0.0121	0.0124	0.0127	0.0131
SUBTOTAL	0.3404	0.3292	0.3371	0.3346	0.3424	0.3504
Small Commercial						
Backbone	0.0149	0.0157	0.0164	0.0167	0.0169	0.0171
Local Transmission	0.0254	0.0260	0.0267	0.0273	0.0280	0.0287
Customer Class Charge	0.0405	0.0276	0.0276	0.0174	0.0175	0.0175
Distribution	0.2533	0.2533	0.2596	0.2661	0.2728	0.2796
Storage	0.0116	0.0118	0.0121	0.0124	0.0127	0.0131
SUBTOTAL	0.3456	0.3344	0.3424	0.3400	0.3479	0.3560
Large Commercial						
Backbone	0.0149	0.0157	0.0164	0.0167	0.0169	0.0171
Local Transmission	0.0254	0.0260	0.0267	0.0273	0.0280	0.0287
Customer Class Charge	0.0300	0.0200	0.0201	0.0099	0.0100	0.0100
Distribution	0.0945	0.0945	0.0969	0.0993	0.1018	0.1043
Storage	0.0102	0.0105	0.0108	0.0110	0.0113	0.0116
SUBTOTAL	0.1750	0.1668	0.1708	0.1642	0.1679	0.1717

(Decision 97-08-055, August 1, 1997, the “Gas Accord”)

3.7.5 Price Variation (Task A5.4)

Obtain data on how these prices vary by season, geographic region and customer class.

Each of the utilities files its monthly rate sheet with the update monthly gas commodity prices with CPUC. These charges are included in the utility price sheets in Gas_data.xls. Seasonal changes in the gas price can be tracked through these monthly rate filings.

Seasonal, class and geographic variations on the non-commodity portions of customer prices are described in each utility’s tariff sheets. See Task A5, #1 for a description of these rates. The rate sheets are attached as Adobe Acrobat Reader files.

3.7.6 CEC Gas Price Forecast (Task A5.5)

Obtain the Commission’s most recent annual natural gas price forecast and monthly forecast consistent with that annual forecast from the Fuels Resources Office.

CEC Natural Gas Market Outlook, June 1998, including Appendices, is attached as an Adobe Acrobat file. The monthly forecast is included in the file Gas_data.xls.

3.7.7 Forecast Gas Prices (Task A5.6)

Compile total marginal gas prices by season, geographic region and customer class. Develop a 30-year forecast of these prices. Provide cost data from IOUs and municipal utilities as specified by the Commission Contract Manager.

Marginal natural gas commodity charges are equal to the natural gas procurement charges under each utility's schedule G-CP. These charges are listed in Gas_data.xls for each utility by month and do not vary across regions or customer classes within each utility.

Other components of marginal cost for each utility and customer type are listed below. Total marginal cost for a customer is equal to the G-CP rate plus the charges listed in the table below.

Table 57: Natural Gas Transmission Costs

Utility/Class	Rate Component	Price	Description
PG&E			
Residential (G-1)	Transportation	0 $/therm	below baseline consumption
		0.52063 $/therm	above baseline
Sml Comm (G-NR1	Transportation	0.30215 $/therm	Summer
		0.38209 $/therm	Winter
SDG&E			
Residential (GR)	Transport / all non-GCP costs	0	Below baseline consumption
		0.615 $/therm	Above baseline consumption
Comm (GN-1)	Transport / all non-GCP costs	0.435 $/therm	0-1000 therms summer
		0.548 $/therm	0-1000 therms winter
		0.212 $/therm	> 1000 therms summer
		0.219 $/therm	> 1000 therms winter
SCG			
Residential (GR)	Transmission	0	Below baseline consumption
		0.51551 $/therm	Above baseline consumption
Comm. (GN-10)	Transmission	0.51551 $/therm	First 100 therms
		0.29042 $/therm	101-4167 therms
		0.13691 $/therm	> 4167 therms

3.8 Marginal Prices for Propane (Task A6)

3.8.1 Data Sources for Commodity (Task A6.1)

Identify present and future sources of propane price data available to the public.

The following sources offer publicly available data on utility and/or supplier propane prices.

At the National Level

EIA Newsletter – Propane Watch – Weekly Status Report
http://www.eia.doe.gov/oil_gas/petroleum/pet_frame.html

EIA Other Petroleum Data Publications
http://www.eia.doe.gov/oil_gas/petroleum/pet_frame.html

MPSC (Michigan Public Service Commission) Michigan Heating Oil and Propane Prices
http://ermisweb.state.mi.us/mpsc/reports/shopp/

BPN BPN's Weekly Propane Newsletter
Pete Ottman, Editor (626) 357-2168

BPN Butane Propane News – Internet Newsletter
http://www.bpnews.com/

BPN Butane Propane News International

EnergySource Internet Service: PropaneGas.com
http://www.propanegas.com/index.html

Bloomberg Energy – Key Energy Spot Market Indicators
http://www.bloomberg.com/
Subscription Required

PH Energy Analysis – Publisher of UK/European on-line reports.
http://www.phenergy.co.uk/services.htm

PMpublishing (Futures) – Comprehensive on-line pricing function.

Quote Watch (Futures) – Internet market information source
http://quotewatch.com/

Platts Oilgram Newsletter

In California

BPN BPN's Weekly Propane Newsletter
Pete Ottman, Editor (626) 357-2168
http://www.bpnews.com/

EIA Petroleum Marketing Monthly (Quantities by District and/or State)
http://www.eia.doe.gov/oil_gas/petroleum/pet_frame.html

AmeriGas – So. California, Sebastapol, throughout the State
http://www.propanegas.com/amerigas/

McPhail Fuel Company – Marin and Sonoma Counties
http://www.mcphails.com/

Campora Propane Distributor

Stockton, CA (209) 466-4105

Globe Gas Corporation, Long Beach, CA
http://www.globepropane.com/

3.8.2 Data Sources for Delivery etc. (Task A6.2)

Identify sources of data on actual production, transportation, distribution or delivery, storage and customer services.

The following sources offer publicly available data on propane production, transportation, distribution or delivery, storage, and customer services.

Production

Propane production points and their corresponding spot prices are listed extensively by the BPN Weekly Propane newsletter. The principal US source postings include Mont Belvieu, TX; Kearney, MO; Conway, KS; West Texas; Selkirk, NY; Apex, NC; Hattiesburg, MS, and the Los Angeles Basin.

BPN BPN's Weekly Propane Newsletter
Pete Ottman, Editor (626) 357-2168

BPN Butane Propane News – Internet Newsletter
http://www.bpnews.com/

PropaneGas.com – Meet the Industry
http://www.propanegas.com/industry/

California - Western Propane Gas Association
(916) 962-2280

California Propane Refinery: LA Basin, Warren

Transportation/Storage

Information on transportation and storage is best covered in various articles in BPN and PropaneGas.com. This information is qualitative with the exception of the resulting spot prices at various basing points around the country. Specific transportation and storage pricing is considered competitive and is not publicly available. In California, basing point spot prices are provided weekly in the BPN newsletter for the following locations:

Los Angeles	San Francisco	McKittrick
Bay Area	San Joaquin Valley	Gaviota
Kern Ridge		

General information on transportation and storage can be accessed via the following web-sites and companies:

Basing Point Suppliers for California

ARCO, Dynegy, Shell, Texaco, and Ultramar

BPN Butane Propane News – Internet Newsletter
http://www.bpnews.com/

PropaneGas.com – Meet the Industry
http://www.propanegas.com/industry/

Distribution / Delivery

Propane in California is distributed by private suppliers, and not by investor owned or municipal utilities. Specific information on the distribution and delivery pricing is competitive and therefore not publicly available. Web sites do not provide end-user pricing for various customer classes *specifically for California*, but this information can be obtained by calling the distributors directly.

Generally, the Yahoo internet search engine maintains a short list (to date) of propane distributors:

http://dir.yahoo.com/Business_and_Economy/Companies/Energy/Petroleum/Natural_Gas/Propane/Distributors/

Below is a sampling of some of the propane distributors in California:

AmeriGas – Throughout California
http://www.propanegas.com/amerigas/

Campora Propane – Central Valley
Stockton, CA (209) 466-4105

Globe Gas Corporation – Southern California
http://www.globepropane.com/

McPhail Fuel Company – Marin and Sonoma Counties
http://www.mcphails.com/

Customer Products and Services

A comprehensive list of supplier products and services is provided by PropaneGas.com http://www.propanegas.com/industry/products.html

Globe Gas Corporation
http://www.globepropane.com/

Associations for General Information

California - Western Propane Gas Association
(916) 962-2280

National Propane Gas Association
http://www.propanegas.com/npga/

Propane Education and Resource Council
http://www.propanecouncil.org/index2.htm

PGAC Propane Gas Association of Canada
http://www.propanegas.ca/

OPA Ontario Propane Association
http://www.propane.ca/

Propane Vehicle Council

Wisconsin Propane Gas Association

3.8.3 Average versus Marginal Prices (Task A6.3)

Identify average propane prices and reasons why there would be differences between average and marginal prices and provide written description of the same.

Marginal prices for propane are essentially the spot prices at production and basing points throughout the country. These vary according to a number of factors including world market conditions for crude oil, crude oil price and availability, seasonal factors, stock quantities, and transportation and distribution costs. Average propane prices published by sources such as the EIA and BPN derived by aggregating spot prices over time, customer class, location, state or region. Average production or basing point prices provided by BPN are determined by the aggregate of individual private producer prices at each refinery or storage point. Average state and regional prices are publicly available by the EIA for weekly, monthly, and annual time periods. The EIA also provides averages by customer class and district.

3.8.4 Variation in Prices (Task A6.4)

Obtain publicly available data on propane prices for production, transportation, distribution or delivery, storage and customer service. Obtain data on how these prices vary by season, geographic region, and customer class.

Public data is not readily available for the unbundled pricing of propane. Spot price information is available at the wholesale level, both from the refineries, and at major distribution pricing points. Retail price information for various classes of customers is available at the national level by region and to a lesser extent by state. (For example, the EIA currently provides state level retail price averages within specific PADD[15] districts, but not PADD

[15] Petroleum Administration for Defense Districts

V, which includes California. More detailed California data will soon be available from the EIA website, however.) Retail prices in California can currently be monitored by contacting the various distributors listed in Task A6.2.

Because of the competitive nature of the propane industry, there is no public information on the unbundled prices of production, transportation, distribution or delivery. Prices for various storage options at the customer level, and for other customer services in general, are available to the customer from local distributors. But these also do not reflect the breakdown of delivered fuel costs.

Propane prices as a whole vary as a function of demand, stock, and delivery. The demand and price varies seasonally based primarily on the overall demand for heating energy. The greatest demand is in the winter months (October-March), typically peaking (nationally) 40% higher than in the summer (Jay Hakes, EIA, 1997). The annual winter demand peaks are highly dependent on the severity of the weather. Prices are also sensitive to the winter stockpile levels of propane, which typically provide 20 percent of mid-winter demand months of December, January and February (Jay Hakes, EIA, 1997). In California, the seasonal price variation for delivered residential propane is less in the south than in the Bay Area and Northern California. For example, AmeriGas in So. California report that their prices for summer and winter hardly fluctuate, whereas their Northern California retailers report price variations of 20 to 50 cents. Campora reports their winter prices for customers in the Central Valley run an average of 15-20% higher in the winter.

Figure 32 shows the weekly wholesale propane prices from the past two years at two pricing points in the Bay Area. The historical data was provided by Campora of Stockton. These point prices, along with others in California, can also be tracked from the BPN website. The graph shows the seasonal price fluctuations, which are much more pronounced in 1996-1997 than in the 1997-1998 winter. Propane demand and prices nationally in the 1997-1998 winter season were quite low due to the abnormally warm weather and the continued low cost of crude oil supply in general.

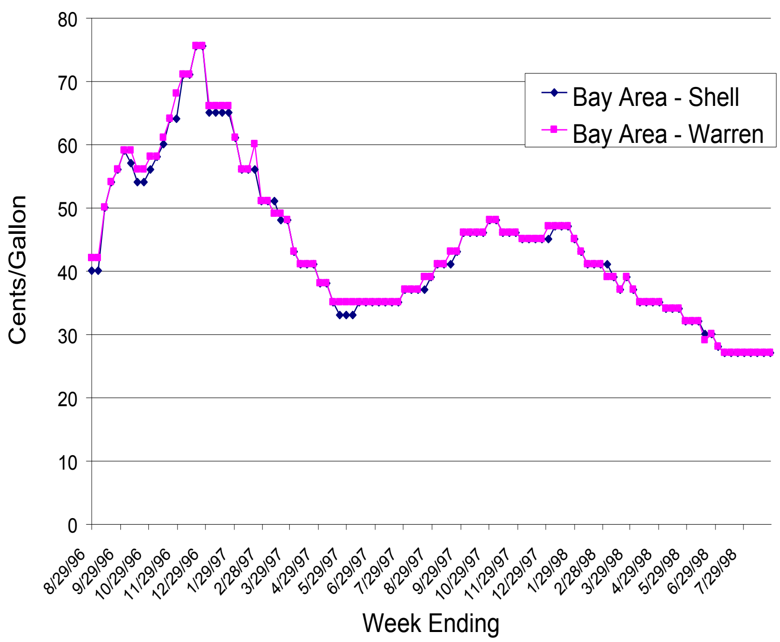


Figure 32: Propane weekly spot prices over the past two years for two Bay Area pricing points

Customer storage options can significantly impact their overall propane usage price. All of the companies contacted have pricing policies or limited service offerings that make it difficult for a residential customer to store enough gas to last through the winter. These policies range from limiting the size of tanks available for lease, to adding significant charges if a customer does not have a regularly scheduled fill service for their tank.

Propane distributors use a model to determine how much a household will use for the month. Most will not lease a tank having greater than one month's capacity in order to ensure the customer will be charged appropriately during the winter price peaks.

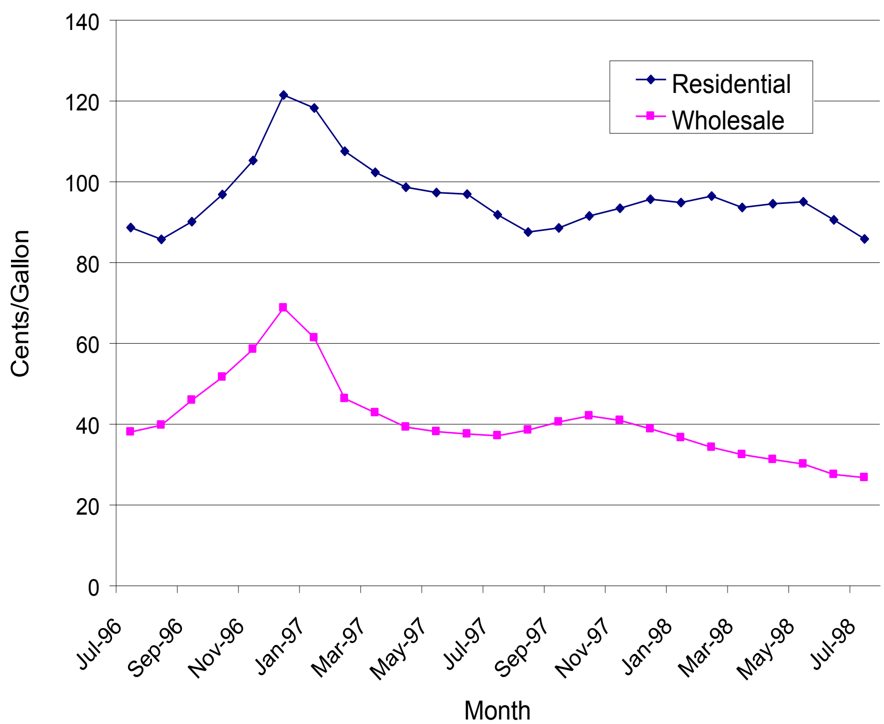
However, McPhail reported that a number of customers own their own tanks and stock up for the winter. The initial costs of these larger tanks are naturally higher, but per-gallon fuel price can be lower. A 1000-gallon tank with the capacity to supply a typical family for a year would cost around $2000, whereas a leased 250-gallon tank would cost approximately $70 a year. Private ownership of a tank also causes added liability for the propane company. They must ensure the tanks are regulated before they can be refilled, and the lack of control results in higher insurance costs. Problems arise when customers will not pay for the necessary tank maintenance, such as to repair worn pipes and regulators. Even though the owner is initially responsible for the maintenance of the tank, the propane supplier typically assumes full liability.

A four-person family in Northern California using propane to supply all appliances and heating needs would typically use 250 gallons a month. Average *delivered* prices are lower if customers are on a routine schedule for fill-up. The location of resident doesn't effect the final price of gas significantly as long as the customer follows a routine schedule. Those that opt to fill-up on a "Will Call" basis will pay substantially more for the special trip.

3.8.5 Marginal Prices (Task A6.5)

Compile total marginal propane prices by season, geographic region and customer class. Develop a 30-year forecast of these propane costs.

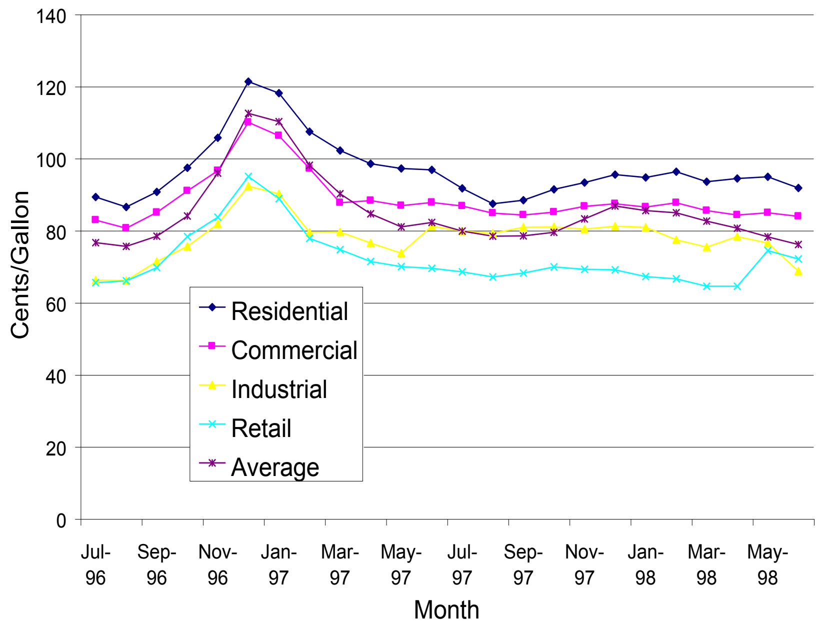
Historic wholesale and residential propane prices at the national level were obtained from the EIA website and are shown in Figure 33. California residential prices for delivered propane are slightly higher than the national average. Southern California residential prices (quoted by AmeriGas) are currently around $1 per gallon, and fluctuate little seasonally. In Northern California the current residential prices are between $1-1.10 per gallon delivered, and increase 15-20% in the winter.



Source: EIA Weekly Petroleum Status Report, September 1998

Figure 33: National residential and wholesale propane prices over the last two years

Figure 34 shows the marginal delivered price of propane nationwide, categorized by customer class and averaged monthly over the last two years. As before, these prices are slightly lower than the current prices in California.



Source: EIA Petroleum Marketing Monthly, September 1998

Figure 34: National propane prices over the last two years categorized by customer class

Prices will most likely stabilize over the next few years for the following reasons:

1. All of California's propane is used locally,
2. Mexico now has a pipeline from Texas for propane
3. California only imports in the winter. (Approx. 15 to 20 percent of total propane.)

Most likely prices will only rise astronomically if there is first a large demand due to bad weather, plants are shut down for repairs, and/or trains are stopped by bad weather. If California is experiencing a shortage of propane, it is purchased from suppliers in Mexico and Canada.

Table 58 and Table 59, below, provide 30-year propane forecasts for Southern and Northern California. Both forecasts were developed using the best available data and information, but have still required some strong assumptions.

The Southern California forecast, below, is based on the current delivered price of $100.4 cents per gallon. Since Southern California gas retailers have indicated that this price is stable from season to season it has been held constant across the months. In order to estimate the 2002 price, this price was escalated with an inflation rate of 2.5%. The table then shows the present value totals for 15 and 30 years at different real discount rates.

Table 58: Southern California Propane Cost Forecast (cents per gallon)

Real	Southern California (cents per gallon)												
Discount Rate		Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
2%	2002	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111
	15-Year PV	$1,424	$1,424	$1,424	$1,424	$1,424	$1,424	$1,424	$1,424	$1,424	$1,424	$1,424	$1,424
	30-Year PV	$2,482	$2,482	$2,482	$2,482	$2,482	$2,482	$2,482	$2,482	$2,482	$2,482	$2,482	$2,482
3%	2002	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111
	15-Year PV	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323
	30-Year PV	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172
4%	2002	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111
	15-Year PV	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232
	30-Year PV	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916

The Northern California propane forecast is based on two main assumptions based on information from our phone survey. First, the current price of propane is approximately 15 cents per gallon higher than the national average, and second there is seasonal variation in propane prices. To generate the forecast we added 15 cents to the national average for each month and then escalated by 2.5% to generate an estimate for the year 2002. This preserved the seasonal variation in the national average. The present total values of the 30 year forecast are then estimated with several real discount rates.

Table 59: Northern California Propane Cost Forecast (cents per gallon)

Real	Northern California (cents per gallon)												
Discount Rate		Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
2%	2002	$114	$111	$116	$123	$133	$150	$147	$135	$129	$125	$124	$123
	15-Year PV	$1,468	$1,427	$1,489	$1,584	$1,703	$1,933	$1,888	$1,736	$1,662	$1,610	$1,591	$1,586
	30-Year PV	$2,559	$2,487	$2,596	$2,761	$2,969	$3,370	$3,290	$3,026	$2,897	$2,806	$2,774	$2,764
3%	2002	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111
	15-Year PV	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323	$1,323
	30-Year PV	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172	$2,172
4%	2002	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111
	15-Year PV	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232	$1,232
	30-Year PV	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916	$1,916

3.9 Energy rates

As described above, utility rates can be built up from costs for energy (commodity), transmission and distribution. The commodity rates are based upon historic bulk rates whereas T&D costs are allocated based upon Peak Capacity Allocation Factors.

The cost savings analyses in the following sections use three types of energy rates that differ by their level of complexity: 1) a temperature and time correlated rate 2) a time of use rate and 3) a flat or constant rate for all hours of the year. Electricity rates could be differentiated on all three levels of complexity. Natural gas and propane rates did not have this level of granularity – the rates were either seasonal or flat. Electricity and propane costs are not differentiated by the customer class. Natural gas distribution systems are significantly more expensive per unit of fuel carried that commercial systems, thus commercial gas rates are lower than residential and this analysis shows the difference.

Table 60: Combination of Rates for Energy Cost Savings Analyses

Rate Description	Electricity Rate based on:	Propane of Natural Gas Rate
Temperature Correlated	Temperature and time	Seasonal
TOU	Time of Use	Seasonal
Flat	Flat	Flat

4 ECONOMIC ANALYSIS OF EFFICIENCY MEASURES

We have used marginal costs to develop costs that vary by geography, time of day and outside temperature. These marginal costs are different in magnitude and relative magnitude between energy sources than either published tariffs or the energy costs used by the CEC to develop the cost-effectiveness of the building standards. This economic analysis tries to answer several questions about how varies energy costing schemes effect the cost savings of various building efficiency measures. It seeks to quantify the cost impacts of the following costing strategies:

1. Time varying costs
2. Marginal costs
3. The change in energy costs between 1990 and 1999
4. Actual utility rates

Marginal electricity and natural gas costs have been developed for each of PG&E's 16 geographic regions as well as for SCE's, SDG&E's and SCG's service territories. A marginal cost model for Propane was not developed because marginal cost information was not available These marginal costs for electricity can take one of three time varying formats: correlation with temperature (a proxy for system load), time-of-use, or flat (constant $ per unit of energy). Natural gas marginal costs are either seasonal or flat. These unit costs have been load weighted so that the aggregation of system loads in any region will result in the same total cost for that region regardless of costing format. Figure 35 shows that the variability in marginal electricity costs is dramatically different between the three time varying formats. The temperature correlated costing allocates most of the T&D marginal costs to a few hours, whereas the time of use rate allocates these costs over a time period for an entire season and the flat costing by definition has no variability.

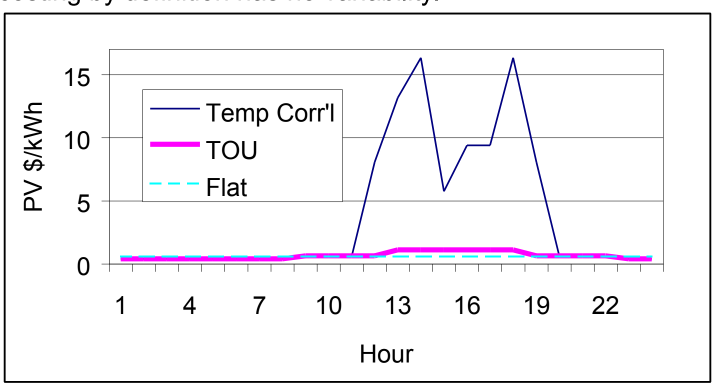


Figure 35: Placerville Marginal Electricity Costs on Peak Day (August)

The marginal costs do not include the recovery of fixed costs nor do they account for profit. They are substantially less than the rates charged consumers. The marginal costs for electricity are a substantially smaller fraction of the rates charged consumers than marginal costs for natural gas; thus an analysis of fuel switching will yield different results using marginal costs than using published utility rates.

The existing standards were developed with a fixed flat unit costs for electricity and natural gas. These unit costs were developed by taking the total revenues for electricity or natural gas and dividing by the total sales. We have used the CEC's deflator (an adjustment for inflation) to bring the unit costs into year 2002 dollars. We have created a time varying unit energy cost based upon these CEC developed unit costs by scaling the marginal costs for electricity and natural gas so that that the resulting flat cost is equal to the flat cost used to develop the standards. Each hour's time varying "CEC cost" is equal to that hour's time varying marginal cost multiplied by a scalar that is (CEC flat unit cost) / (marginal flat unit cost).

In 1990, the real rates for energy were higher than they are now and the projections of cost and inflation were higher than current projections. Flat unit costs are developed using the "CEC methodology" used in 1990 but with today's energy values and with today's expectations of energy inflation. The time varying components of temperature correlated and time of use unit costs are created in the same manner as those for the "CEC costs" but with a different scalar. Propane unit costs are included and the same methodology is applied. The electricity data comes from the CEC forecasting division[16]. The natural gas data comes from the Energy Information Administration[17]. The Propane cost data comes from E3's analysis of rates performed for this project. All prices are brought to year 2002 values using the CEC developed deflators (inflation adjustment factors).

As a reality check, these costing methods are compared to actual rate structures used by the three major California electric utilities and the three major California natural gas utilities. Seasonal Propane rates are also included in this comparison. We applied the PG&E rates to Fresno, Oakland and Shasta, SCE and SCG rates to China Lake and SDG&E rates to Long Beach (a southern coastal climate similar to that experienced by many of SDG&E customers). The rates used in the commercial cost savings analysis from each of the three major electric utilities and three major gas utilities are shown in the table below.

Table 61 Commercial Electricity and Natural Gas Rates Used Cost Savings Analysis

Utility	Electricity Rate	Natural Gas Rate
PG&E	E-19S	G-NR1
SCE	TOU-GS-2	----
SCG	---	GN-10
SDG&E	AL-TOU	GN-1

The following table summarizes the analysis matrix of costing methods and time varying formats that were applied to the hourly outputs of building energy simulations.

Table 62: Analysis Energy Costing Matrix

	Electricity	Natural Gas	Propane
CEC Model	Flat TOU Temp Correlated	Flat Seasonal	------------
CEC Methodology	Flat TOU Temp Correlated	Flat Seasonal	Flat Seasonal
Marginal Cost	Flat TOU Temp Correlated	Flat Seasonal	Not available
Published Rates	TOU	Seasonal	Seasonal

[16] This data can be found in *Table 9 Outlook of Energy Prices*, in the **1998 Baseline Energy Outlook**. California Energy Commission, P300-98-012

[17] **The State Energy and Expenditure Report 1995**, Energy Information Administration, this document can be downloaded from http://www.eia.doe.gov/emeu/sep/states.html

5 NONRESIDENTIAL ENERGY CODE ISSUES

Much of this Chapter was prepared by project team member, Eley Associates with further analysis by the Heschong Mahone Group..

5.1 Commercial Building Efficiency Cost Savings Analysis

5.1.1 Summary

Nine building envelope or equipment configurations which impact energy performance (plus base case) were modeled on six different prototype buildings in five climate zones. The goal of the exercise was to develop whole building electricity and natural gas hourly load profiles. These load profiles were used to estimate how these measures would be valued in a source energy based standard as compared to a time-varying energy cost based system. We expected the analysis to show a significant difference between the source energy savings and the energy cost savings for at least some of the measures in some of the building types

5.1.2 Background

Lifecycle Cost Analysis

The Title 24 Energy Standards have the legislative mandate of being "cost-effective ... when amortized over the economic life of the structure". The standards are based on a lifecycle cost analysis which demonstrates that the required levels of energy efficiency (for walls, glazing, package units, etc) are the lowest life-cycle cost options for a typical building of a particular type in a particular climate zone. The lifecycle cost analysis is based on a single average energy cost, i.e. not time varying. The methodology does not account for the fact that some energy efficiency measures save more energy during high energy cost periods than during low energy cost periods. Thus these measures may be undervalued in the current methodology. Conversely some measures that save more energy at off-peak times may be overvalued. An incorrectly valued measure means that the standard could encourage or require measures that are not cost-effective or discourage measures that are cost-effective. The standard could be improved by converting from a flat energy cost rate to a time-varying energy cost rate that is more reflective of the expected future cost of energy.

The current method defines life-cycle cost as the initial cost premium plus the present value of future energy costs.

Life Cycle Cost = Initial Cost Premium + Present Value Energy Cost

Present Value Energy Cost = Annual Electricity x 1.03 + Annual Gas x 6.45

where

1.03 = present value of 1 kWh of electricity over life of building

6.45 = present value of 1 therm of natural gas over life of building

If time-varying energy costs are accounted for, a separate present value term needs to be determined for each time period. The following equation shows how this might work if the year is divided into five time periods. Energy use would need to be tabulated separately for each time period and a present value of energy would need to be calculated for each time period.

$$\begin{aligned}\text{Present Value energy cost} &= \text{ElectricityUse}_{\text{SummerPeak}} \times \text{PVElectricityCost}_{\text{SummerPeak}}\\ &+ \text{ElectricityUse}_{\text{SummerShoulder}} \times \text{PVElectricityCost}_{\text{SummerShoulder}}\\ &+ \text{ElectricityUse}_{\text{SummerOffPeak}} \times \text{PVElectricityCost}_{\text{SummerOffPeak}}\\ &+ \text{ElectricityUse}_{\text{WinterShoulder}} \times \text{PVElectricityCost}_{\text{WinterShoulder}}\end{aligned}$$

+ $ElectricityUse_{WinterOffPeak}$	x $PVElectricityCost_{WinterOffPeak}$
+ $GasUse_{Summer}$	x $PVGasCost_{Summer}$
+ $GasUse_{Winter}$	x $PVGasCost_{Winter}$

ACM Manual

In addition to using a flat energy cost rate to develop the standard, the flat rate is also used in the performance compliance method to determine how well a particular combination of measures performs relative to the required prescriptive package of measures. Thus measures that are incorrectly valued in the lifecycle cost analysis will also be incorrectly valued in the performance compliance method.

Converting from source energy to energy cost in the performance compliance method can be quite simple. The current procedure is to compute source energy budgets for a standard building and the proposed building and compare the two results. The new procedure would be to compute energy cost budgets for a standard building and the proposed building and compare the two. Thus, at a minimum, the only changes that are required are:

- To replace Table 1-B Source Energy Conversion Rates with standard time-of-use utility rates.
- To recalculate the reference program results (dollars instead of source Btu) for all of the performance tests (chapter 5).

No changes would have to be made in the way that the standard building or the proposed building are modeled. However, there are some significant modifications that would improve the accuracy of the ACM that should be considered. These are below. The numbering in the headings refers to section numbers in the *ACM Approval Manual*.

2.2.2.6 Interzone Walls

The amount of internal mass can affect peak loads which affects energy costs.

Currently: The ACM requires that interior walls are modeled as air walls. All internal mass falls into "furniture". The standard building is always modeled as having the same internal mass as the proposed building. (see sections 2.2.2.6 and 2.2.2.13) Thus a designer cannot take credit for increasing internal mass.

Proposed change: Interior walls should be non-mass walls in the standard building and user input in the proposed building.

2.2.2.11 Concrete Slab Floors on Grade

As with interzone walls, there should be a way to take credit for having a slab floor verses a raised floor. Currently the standard building uses the same floor as the proposed building (2.2.2.11).

2.3.2 Occupancy Lighting

Currently, lighting controls are accounted for by adjusting the lighting power density. This assumes that the effect of lighting controls is the same for every hour of the day. Some controls, however, may be more effective at certain times. For example, daylighting controls are more likely to be effective during the day especially on sunny days, i.e. concurrent with peak utility rates and peak buildings loads. A more accurate way to account for lighting controls might be to adjust the lighting schedule for the appropriate hours rather than the lighting power density. A better option for daylighting controls is to use the DAYLIGHTING function in DOE-2.

2.3.3 Occupancy Schedules

Currently only three schedule types are used in the ACM: nonresidential, residential, and hotel function. In order to more accurately model the energy cost savings for buildings with diverse occupancy schedules it may be advisable to expand this list. For example, currently a theater is modelled as non-residential (i.e. 9-5 weekdays) but theaters are typically used primarily in the evenings when energy prices are lower. Classrooms are also modeled as nonresidential but most schools are closed or lightly used during the summer when peak rates are in effect. It may be appropriate to separate schedules for each of the occupancy types in Table 2-1 or even for all of the sub-occupancy types in Table 2-2. Even more schedule choices may be needed such as classroom--year round and class room--summer closed.

2.4.2.1 to 2.4.2.3 Primary Heating and Cooling Equipment

In sections 2.4.2.1-3 (primary systems, heating/cooling equipment) the ACM should also be required to be capable of modeling:

- thermal energy storage systems
- geothermal heat pumps
- gas heat pumps
- engine-driven compression chillers.

Additionally, the following should be changed from optional to required capabilities:

- absorption chillers
- indirect evaporative cooling equipment.

Minimum conformance tests will need to be added to demonstrate the ACMs ability to model these systems. This should not be a problem since DOE-2 is capable of modeling all of these systems.

The following systems should also be considered at least as optional capabilities but may pose more of a problem since DOE-2 is not capable of modeling them currently:

- solar hot water
- solar electricity (PV)
- load curtailment

2.4.2.6 Equipment Performance Curves except Electric Chillers

The ACM Manual requires that the reference design and the proposed design use the packaged unit performance curves specified in the DOE-2.1E Supplement. No tradeoffs are allowed. Since the DOE-2.1E Supplement gives no guidance on using the non-default curves it is clear that the user is to use the DOE-2 default curve (suction valve-two compressors) for all packaged equipment, regardless of unloading mechanism.

We recommend a single default curve for the reference design but for the proposed design the user should be required to select the predefined part-load performance curve that most closely matches the packaged units unloading mechanism (hot gas bypass, suction valve-one compressor, etc). See Section 5.3.3, for futher discussion of part load performance.

5.1.3 Analysis Inputs

Building Prototypes

The six building prototypes are:

- Office
- Hospital
- Industrial Process
- School (classrooms only)
- Hotel (guestrooms only)
- Retail

These building types were chosen because they represent a large percentage of the total stock of commercial buildings and because there is a significant diversity of occupancy patterns and operating schedules between the building types. The constructions, loads, schedules, and HVAC systems for the prototypes are described in detail in Table 63. The prototype models have been reviewed by industry experts who concluded that they are accurate representations of the existing stock of buildings of these types.

Table 63: Commercial Building Simulation Model Descriptions

	BUILDING TYPE					
	Office	Hospital	Process	Classrooms	Retail	Hotel Guest
Construction						
number of stories	6	5	1	3	3	5
front orientation	SE	SE	SE	SE	SE	SE
width	140	200	300	300	200	400
depth	140	100	300	90.0	200	50
shape	box	Rect	box	L-shape	box	L-shape
total floor area	117600	100000	90000	137700	120000	112500
Floor to Floor Height	13	14	20	13	15	10
Plenum	3	4	0	3	3	0
window-wall ratio	0.35	0.15	0.05	0.25	0.1	0.25
window type	single bronze	single bronze	single bronze	single bronze	single bronze	single bronze
window shading	med. blinds	med. blinds	med. blinds	med. blinds	none	med. blinds
wall type	R-11 mtl. frm.	R-11 mass	R-0 mass	R-11 mtl. frm.	R-11 mtl. frm.	R-11 mtl. frm.
roof type	R-19 mass	R-19 mass	R-19 mtl frm	R-19 mass	R-19 mass	R-19 mass
floor type	R-11 mass	R-11 mass	Simulated Slab	R-11 mass	R-11 mass	R-11 mass
wall absorp.	0.7	0.7	0.7	0.7	0.7	0.7
roof absorp.	0.7	0.7	0.7	0.7	0.7	0.7
Loads						
lighting power	1.5	1.6	1.5	1.4	2.6	1.2
equipment power	0.75	1	5	0.5	0.25	0.25
occupant density	250	200	750	75	300	250
infiltration (perim.)	0.2	0.2	0.2	0.5	0.5	0.5
infiltration (int.)	0	0	0	0	0	0

	BUILDING TYPE					
	Office	Hospital	Process	Classrooms	Retail	Hotel Guest
Operating Schedules						
Cooling setpoint (occupied)	73	73	73	73	73	73
Cooling setpoint (unoccupied)	99	n.a.	99 or na	99	99	na
Heating setpoint (occupied)	70	70	68	70	70	70
Heating setpoint (unoccupied)	55	n.a.	55 or na	55	55	na
Fan schedule	6am -7pm	24 hr	24	7am - 10pm	8am -10pm	24 hr
operating schedule	5 days/week	24 hr	2 shift	w/ summer brk	7 days/week	7 days/week
Lighting schedule	7am - 7pm	7am - 6pm	7am - 6pm	7am - 10pm	8am - 10pm	6am - 10pm
Lighting off-hour fraction	0.2	0.7	0.2	0.2	0.2	0.5
Misc. equip. schedule	7am - 6pm	7am - 6pm	7am - 6pm	7am - 10pm	8am - 10pm	6am - 10pm
Equip. off-hour fraction	0.5	0.7	0.2	0.5	0.5	0.5
Occupants	8am -6pm	24 hr	8am -1am	8am - 10pm	8am - 10pm	24 hr
System Description						
System type	VAV reheat	CV reheat	CV reheat	CV reheat	FPFC	FPFC
Economizer	yes	yes	yes	yes	no	no
Fan SP	4.0	5.0	4.0	4.0	1.0	1.0
Fan eff	0.70	0.70	0.70	0.70	0.50	0.50
Fan motor eff	0.85	0.85	0.85	0.85	0.85	0.85
Fan drive eff	0.95	0.95	0.95	0.95	0.95	0.95
Fan control	speed	constant	constant	constant	constant	constant
Min. air flow frac.	0.4	1.0	1.0	1.0	1.0	1.0
OA cfm/person	37.5	50	75	15	75	50
SAT setpoint	55	55	55	55	55	55
SAT control	OA reset	OA reset	constant	OA reset	na	na
Coil oversize ratios	1.5	1.5	1.5	1.5	1.5	1.5
Night cycle control	cycle on any	cycle on any	cycle on any	cycle on any	cycle on any	cycle on any
Zone Air						
Zone Reheat	yes	yes	yes	yes	no	no
Reheat delta T	45	45	45	45	na	na
Source	hot-water	hot-water	hot-water	hot-water	na	na

Energy Efficiency Measures

The measures that were modeled are: daylighting controls, thermal energy storage, natural gas cooling, electric resistance heating, and high performance glazing. The details of these measures are described in the table below. No particular effort was made while modeling the measures to maximize the energy cost savings or to maximize the difference between source savings and cost savings. For example, the cost savings from thermal storage depend on many factors including the storage charging and discharging periods. One reason that no particular effort was made to maximize cost savings is that we did not know the energy cost rate schedules. In future exercise it probably makes sense to try to tailor the measures or combinations of measures in order to maximize the energy cost savings or to maximize the difference between source savings and cost savings and thereby make a stronger argument for changing the Standard.

Daylighting was selected for analysis because the savings are more likely to occur during peak rate periods than during off-peak periods thus there is a good chance that daylighting controls are not accurately valued in the current scheme. Thermal storage was chosen because it definitely is not accurately valued in the current scheme. Thermal storage systems always consume more total energy than standard systems but they consume it during off-peak periods when energy is cheaper. Gas cooling was chosen to determine the relative advantage of trading electric consumption for gas consumption during peak periods. Electric heat was selected in order to evaluate the relative advantage or disadvantage of trading gas consumption for electricity consumption during off-peak periods. High performance glazing was selected in order to see how a measure that does not have a clear time of use advantage or disadvantage might fare under a energy cost-based scheme, i.e. is something that may have been cost-effective in a source energy-based standard still cost effective in a new scheme?

Table 64: Description of Efficiency Measures

Daylighting controls	Continuous dimming control on perimeter zones, illuminance = 50.00 fc, control fraction = 1.0. Glazing changed to double clear low-E (U_{cog} = 0.29, SC = 0.48, $SHGC_{0°}$ = 0.42, VLT = 0.68) [Base Case glazing = single bronze (U_{cog} = 1.09, SC = 0.71, $SHGC_{0°}$ = 0.61, VLT = 0.53)] This is compared to a special base case with the same glazing but with no daylighting controls
Thermal energy storage	Ice on coil, located in conditioned space, charging from 10:00pm to 6:00am, discharging from 8:00am to 9:00pm, 100% load storage capacity, tank loss coefficient = 0.0.
Gas cooling	Engine-driven chiller, COP = 1.4, Compressor COP = 5.3, electrical usage = 0.002 W/Btuh, min. operating point = 0.066, autosized.
Electric heat	Electric resistance heat.
Low-E windows	Glazing changed to double clear low-E (U_{cog} = 0.29, SC = 0.48, $SHGC_{0°}$ = 0.42, VLT = 0.68) [Base Case glazing = single bronze (U_{cog} = 1.09, SC = 0.71, $SHGC_{0°}$ = 0.61, VLT = 0.53)]
High SC	Glazing changed to single glazed clear glass (U_{cog} = 1.09, SC = 0.94, $SHGC_{0°}$ = 0.82, VLT = 0.88)
Low-LPD	Lighting power density reduced to 80% of base case values while maintaining same control schedule.
Cool Roof	Solar absorptance of roof changed from 70% to 30%.
Efficient Chiller	COP of chiller increased by 25%

Source Energy Savings vs Energy Cost Savings

Source energy savings are simply the difference between the total annual source energy consumption of the building with and without a particular measure. Energy Cost savings are more difficult to compute because energy use must be separated into how every many TOU rate periods there are in the rate schedule. Energy cost may also include both energy charges (e.g. $/kWh) and demand charges (e.g. $/kW).

A significant difference between source energy savings and energy cost savings indicates that the particular measure is incorrectly valued in the ACM manual tradeoff method.

Differences in Present Value Energy Cost

In order to estimate the impacts of converting to a new system on the Standard itself we can compare the lifecycle energy cost of measures using the source energy method and an energy cost method. In the current method:

Present Value Energy Cost = Annual Electricity x 1.03 + Annual Gas x 6.45

where

1.03 = present value of 1 kWh of electricity over life of building

6.45 = present value of 1 therm of natural gas over life of building

The present value energy cost savings of a particular measure is simply the difference between the present value energy cost of a building with and without the measure.

In order to compute the present value energy cost of a measure in a cost-based system it is necessary to compute the present value of a kWh of electricity in each rate period. For a typical 5 rate period schedule:

$$
\begin{aligned}
\text{Present Value energy cost} \quad &= \text{ElectricityUse}_{\text{SummerPeak}} \times \text{PVElectricityCost}_{\text{SummerPeak}} \\
&+ \text{ElectricityUse}_{\text{SummerShoulder}} \times \text{PVElectricityCost}_{\text{SummerShoulder}} \\
&+ \text{ElectricityUse}_{\text{SummerOffPeak}} \times \text{PVElectricityCost}_{\text{SummerOffPeak}} \\
&+ \text{ElectricityUse}_{\text{WinterShoulder}} \times \text{PVElectricityCost}_{\text{WinterShoulder}} \\
&+ \text{ElectricityUse}_{\text{WinterOffPeak}} \times \text{PVElectricityCost}_{\text{WinterOffPeak}} \\
&+ \text{GasUse}_{\text{Summer}} \times \text{PVGasCost}_{\text{Summer}} \\
&+ \text{GasUse}_{\text{Winter}} \times \text{PVGasCost}_{\text{Winter}}
\end{aligned}
$$

If a particular measure has a higher PV energy cost savings when computed with a cost-based system than with the current source-based system then that measure is undervalued in the lifecycle analysis and in the Standard itself. For example, if the high performance glazing shows a higher PV energy cost savings with the cost-based method then perhaps the glazing requirements in the Standard should be more stringent. Conversely, if a particular measure has a lower PV energy cost savings when computed with a cost-based system than with the current source-based system then that measure is overvalued.

5.1.4 Cost Savings Results

As described in Section 3.9, we are comparing three levels of complexity for energy rates: Temperature Correlated, Time of Use, and Flat. We anticipate that the most complex rate type, the temperature correlated rate most accurately captures the true cost of service on an hour by hour basis. We had hypothesized that the TOU rates would more closely approximate the temperature-correlated rate and that there would be a significantly different outcome based upon rates. In many cases, these preliminary results do not strongly support this hypothesis. Equally interesting is that a TOU rate some times produces results that are contrary to the results from a temperature correlated rate.

Depending upon the building type, the cost savings results were noticeably different. Office buildings behave substantially different from other commercial building types. Thus illustrating the danger of basing energy standards on one “typical” building type.

In addition, using representative costs for propane yielded substantially different results than using natural gas costs. This is not surprising since propane is approximately twice the price of natural gas. The main impact of propane as a fuel source, is that envelope measures look more attractive relative to natural gas and that electric heating had less additional annual energy costs compared to propane as compared to natural gas.

How to read the graphs

Each of the graphs lists the present valued (15 year period, 3% discount rate) energy cost savings for a given efficiency measure per square foot of building floor space for 6 building types. There are 14 bars for each building type. They are grouped by the five types of analysis: 1) blues for marginal costs, 2) greens for CEC original energy costs used to develop the 1992 standards, 3)yellows for the CEC methodology applied to current energy rates and using natural gas as the heating fuel, 4) reds for the CEC methodology applied to current energy rates and using propane as the heating fuel 5) dark blue for existing utility rates with natural gas as the heating fuel and grey for existing utility rates with propane as the heating fuel.

Within each "family" of bars the analysis goes from the most elaborate costing scheme (temperature correlated) to the least (flat). Natural gas and propane costs vary by season rather than by time of day or correlated with temperature. We have paired a seasonal gas or propane costs with the temperature correlated or time of use electric costs. Similarly we have paired the flat natural gas and propane costs with flat electricity costs.

Each city has two pages of corresponding graphs for the nine building energy efficiency parametric options analyzed. The top of the page for each city contains information about the flat energy costs used in the analysis for electricity, natural gas and propane and the average costs of electricity, natural gas and propane for the base case of each building type.

Below the energy cost information is the color key describing the costing method for each bar. If you have a black and white copy, the three marginal cost bars come first (temperature correlated, TOU and flat) followed by the other bars described from left to right in the color key.

To the right of each of the graphs are a tabular listing of the electricity and "fuel" (natural gas or propane) savings. These energy savings values help to understand the results. Note that these energy figures are <u>not</u> normalized into energy intensities. Most of the buildings have floor areas around 100,000 sq. ft. See Table 63 in the previous section for the exact area figures.

Only the China Lake cost savings results are listed below. The results for the four other locations are contained in the appendix at the back of this report.

Cost Savings Figures for China Lake

Commentary on Cost Savings Figures

As few comments can be made about each graph.

- Daylighting. Though daylighting preferentially reduces summer peak demand, the time period of savings (most of the daytime hours including weekends) is broader than the TOU period and certainly the temperature correlated TOU period. TOU and temperature correlated costing consistently had 5% to 20% higher savings than a flat costing.
- Thermal energy storage. For most building types and for all climates TES showed substantial savings under a TOU or temperature correlated energy costs compared to a flat costs. The hospital and process buildings showed negative savings under the TOU and temperature correlated costs because the modeling assumption of allowing DOE-2 to autosize the TES chiller size is an unreasonable assumption for a 24 hour load. A quick reality check of fixing the TES chiller size at the base case chiller size resulted in positive TOU/temp. correlated savings for the hospital and process models. In general, the TES savings for all building types can be improved by optimizing the chiller size, control strategy and other factors with respect to the TOU or temperature correlated rate.
- Gas cooling. For most building types, gas cooling fares substantially better under the TOU costs than the flat costs and, in general, slightly better than the temperature correlated costs. The TOU costs captures most of the hours that air conditioning is active in office buildings and classrooms and thus the savings are higher than the other rates. The temperature based costs preferentially weights the hours that the air conditioning is working the hardest but does not allocate much cost to the many hours that are not at peak temperatures but still require cooling.
- Electric resistance heating. Natural gas is substantially cheaper than electricity, however, a flat electricity cost overvalues the cost of electric heating, much of which would occur during electrical off-peak rate periods. Propane is substantially more expensive than natural gas and as a result, replacing electric heat with propane heat results in substantially less energy cost savings than replacing electric heat with natural gas.
- Low-e glass. Single glazed bronze glass was compared with double pane low-e clear glass. The main effect of this measure is to reduce conduction by 70% along with a 30% reduction in solar gain. The savings from low-e glass occurs throughout the year. Thus the cost savings are comparable regardless of the rate format used (temperature correlated, time of use or flat). Low-e glass reduces heating loads; thus cost savings from low-e glass are increased if higher priced propane is used for heating instead of natural gas. The small amounts of glazing in the retail and process buildings result in little effects from low-e glass.
- High shading coefficient (SC) glass. Single glazed clear glass replaces the bronze glass used in the base case model. The purpose of this comparison is to discover how purely solar gain effects are reflected in different rate structures. These results can be compared to the low-e glass for evaluating the time varying effects of solar gain versus thermal transmittance effects. The heating results are counter-intuitive – more solar gain leading to higher heating fuel consumption in hospital, office and classrooms. These systems are either constant volume of variable volume air systems with reheat. The higher peak loads from high shading coefficient glass result in higher peak supply fan flow rates. These higher flow rates result in greater simultaneous heating and cooling requirements during low cooling load periods. This hypothesis was verified by fixing the peak supply fan flow rate and comparing the results.
- Low lighting power density (LPD). Building types that have lighting schedules that match the time of use periods and temperatures periods that are associated with high electricity prices (such as office and retail occupancies) have slightly greater savings from LPD reductions under temperature correlated and TOU rates than flat rates. The other building types show the opposite effect.
- Low absorptivity roof (Cool Roof). A low absorptivity roof reflects most of the solar radiation falling on it rather than absorbing it. All building types have the same amount of insulation (R-19 with steel framing which reduces the insulating level to approximately R-10). All of the buildings except the process

building have high mass roofs (thermal capacitance, HC = 10.6 Btu/°F·ft^2). In contrast, the process building has a lightweight roof (thermal capacitance, HC = 2.0 Btu/°F·ft^2). Less solar gains are transferred through the high mass roofs because some of this heat is stored and re-released back to the ambient air during diurnal ambient temperature swings. In general the different rates did not have much impact on cost savings except for the office building in China Lake. The office building in China Lake had dramatically greater savings under the temperature and time of use rates as compared to the flat rate.

- Efficient Chiller. Chiller loads are greatest during peak time of use periods when it is hot outside, thus it is not surprising that temperature correlated and TOU energy costing methods would result in higher cost savings than using a flat energy cost.

5.2 Nonresidential Cost Savings Study Conclusions

Several repeating patterns can be discerned from the results of this study of the effects time varying and marginal rates might have on nonresidential efficiency standards.

- Different building types respond differently to the efficiency measures modeled.
- Marginal costs do not value energy as high as rates, or the previously used energy valuation methods.
- The projection of energy costs used in 1990 by the CEC to determine the cost effectiveness of the standards is higher in real dollars than if this same projection was done today.
- Using natural gas costs to represent any fuel costs substantially undervalues the cost of propane.
- Time varying energy costs (temperature correlated of TOU costing) increases the cost savings value of high efficiency air conditioning and daylighting controls.
- Time varying energy costs substantially enhance the cost effectiveness of thermal energy storage and gas cooling.
- Improvements in areas that are considered the typical scope of energy standards such as increasing the efficiency of the mechanical systems, the building envelope and lighting systems are not dramatically affected by a time varying energy rate.
- Caution should be applied to relaxing standards on envelope requirements in exchange for using technologies which benefit from time varying rates such as thermal energy storage which can be more readily replaced or disabled.
- Efficiency requirements for buildings should be different depending upon the heating sources used electricity, natural gas and propane.

5.3 Air Conditioner Part-Load Efficiency

5.3.1 Part Load Efficiency in DOE-2

For non-residential packaged equipment (packaged single zone, packaged VAV, packaged multi-zone), DOE-2 uses default curve SDL-C18 to determine the Cooling EIR as a function of part load ration (DOE-2 keyword = COOL-EIR-FPLR). According to this curve, part load efficiency is always slightly worse than full load efficiency and considerably worse at very low loads (<15% full load). According to the DOE-2.1E Supplement documentation (Nov 1993), this curve "comes from data in the ICES Report ANL/CES/TE 78-2[18]. This curve corresponds to Curve 4 on p. 10 of that report." Page 10 of the ICES report indicates that Curve 4 corresponds to suction valve-lift, two compressors.

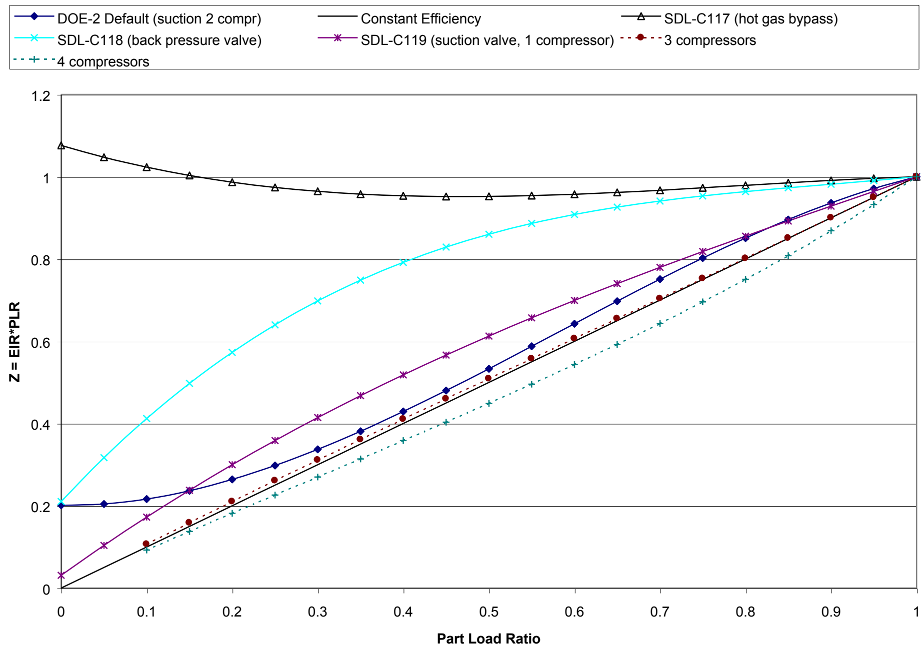


Figure 36: Part load efficiency for different unloading mechanisms

The Supplement also describes three other part load curves from the ICES report: SDL-C117 (hot gas bypass), SDL-C118 (back pressure valve) and SDL-C119 (suction valve-lift, single compressor). The Supplement does not give any guidance about when to use these curves. Figure 1 shows the DOE-2 default curve, the three other curves available in DOE-2, and a straight line (constant efficiency) curve.

The ICES report itself also provides part load data on two other capacity control methods: suction valve lift unloading three compressors, and suction valve lift unloading four compressors. (see Figure 36). DOE-2 does not include predefined coefficients for these methods but they can be generated. The ICES report specifies a minimum range for all six capacity control curves. For example, the capacity range for the suction valve-lift two compressors is from 15% to 100%. DOE-2 does specify a minimum range for the part load curve and therefore the curve is incorrectly applied at low load. The curves in the ICES report appear to be based on a 1975 report by Carrier entitled “Reciprocating Liquid Chillers Applications Data” and Carrier’s 1965 “Handbook of Air Conditioning System Design”.

5.3.2 Impact of Part Load Curves

To understand the impact of the part-load function on simulation results, we simulated a hypothetical Bay Area office building in DOE-2 using the four DOE-2 curves, as well as a constant efficiency COOL-EIR-FPLR curve. The cooling energy results compared to the constant efficiency amount:

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[18] AUTHOR: Christian, Jeffrey E.
TITLE: Central cooling -- compressive chillers
PUBLISHER: Dept. of Energy, Argonne National Laboratory; for sale by NTIS
YEAR: 1978
SERIES: ANL/CES/TE ; 78-2
COVER: ICES, Integrated Community Energy Systems, technology evaluations. Prepared under contract W-31-109-Eng-38 with the U.S. Dept. of Energy. March 1978.

SDL-C18 (default)	17% more cooling energy than constant efficiency
SDL-C117 (hot gas bypass)	270% more
SDL-C118 (back pressure valve)	50% more
SDL-C119 (suction valve-1 compr.)	40% more

We have tried unsuccessfully to get part load efficiency data from equipment manufacturers. We need PLR (part load ratio) and EER at a few points to fit a curve. Certainly manufacturers have this data because it is necessary for calculating IPLV. So far, however, they have not been forthcoming.

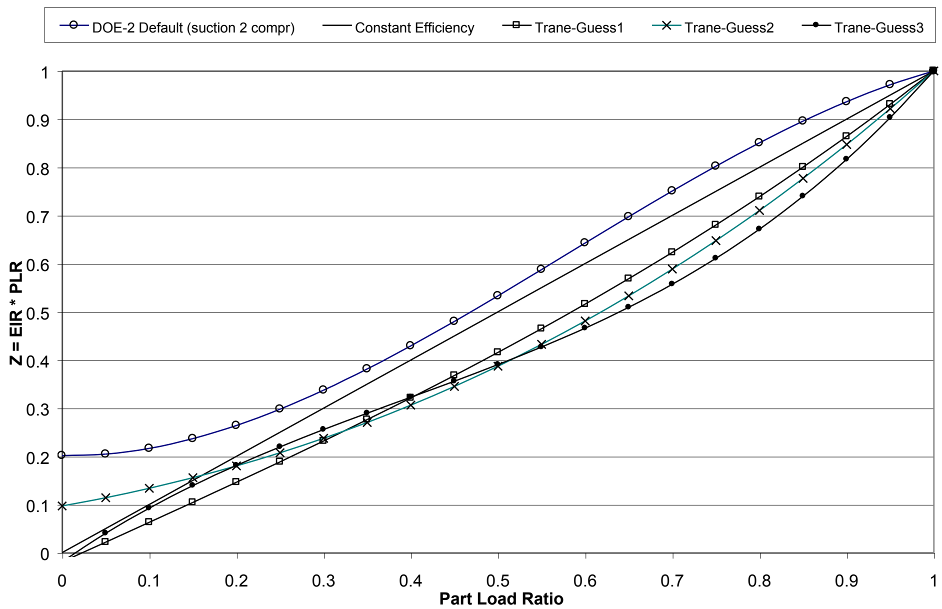

Figure 37: Potential Part Load Efficiency of 90 Ton Trane Intellipak Unit

However, we have some clues about part load performance from available manufacturer's data: full load EER, unit capacity steps, and IPLV, which is a weighted average of EERs at the part load steps (refer to ARI Standard 340/360). For example, Trane's February 1997 catalog lists EER of 9.2 and IPLV of 11.10 for a 90 ton Intellipak rooftop packaged unit with capacity steps at 69%, 38%, and 19%. (This machine has 6 compressors. It is not immediately clear from the catalog what the unloading mechanism is; both hot gas bypass and suction service valves are listed as optional features.) The weighted average of the EER at these steps has to be better than the EER at full load. Using the formula for IPLV we took a few guesses at what the three part load EERs could be (e.g. 9.2, 11, 12, 10) We developed curves for several guesses and ran them in the simulation model (see Figure 37). We came up with:

Trane 90 ton	13-25% less cooling energy than constant efficiency

Clearly the part load curve has a very significant impact on simulation results. Moreover, using a single part load efficiency assumption for all packaged units, regardless of the unloading mechanism or the number of compressors, leaves much room for error.

We have attempted to collect actual monitored data on packaged units installed in the field in order to compare the DOE-2 curves and manufacturer's EER and IPLV data to actual performance. Unfortunately, to date, we have not been able to collect data with which to make a meaningful comparison.

5.3.3 ACM Manual

The ACM Manual Section 2.4.2.6 requires that the reference design and the proposed design use the packaged unit performance curves specified in the DOE-2.1E Supplement. No tradeoffs are allowed. Since the DOE-2.1E

Supplement gives no guidance on using the non-default curves it is clear that the user is to use the DOE-2 default curve (suction valve-two compressors) for all packaged equipment, regardless of unloading mechanism.

For electric chillers, on the other hand, the ACM Manual specifies two default performance curves for the reference design: one for air-cooled chillers, and one for water-cooled chillers. For the proposed design the user can use the default curves or generate a custom curve using ARI-550/590 certified data (see ACM Manual Section 2.4.2.33). Thus tradeoffs are allowed.

There are a couple of options for modifying the ACM Manual to more accurately simulate part-load performance for packaged units. One option is to develop a similar methodology for packaged units to the one for chillers. The default curve (suction valve-two compressors) could be used for the reference design but the user could have the option of generating custom performance curves for the proposed design using ARI Standard 340/360 certified data. We do not recommend this option because of the difficulty obtaining part-load performance data and because the methodology is fairly complex and not something a typical ACM user would be familiar with. Given these two drawbacks, it is unlikely that custom packaged unit curves would be generated by many or any users. Moreover, the opens up the possibility that users could intentionally or unintentionally use incorrect part-load data resulting in highly erroneous simulation results.

We recommend a single default curve for the reference design but for the proposed design the user should be required to select the predefined part-load performance curve that most closely matches the packaged units unloading mechanism (hot gas bypass, suction valve-one compressor, etc). This option would be much easier to use. It would greatly improve simulation accuracy, and it would allow appropriate tradeoffs for more or less efficient unloading mechanisms. A simple step that would make this option even easier to employ would be if the CEC maintained a table on its website of popular packaged units and the corresponding part load efficiency curves that are most accurate.

Regardless of which option for modifying the ACM Manual is chosen, we strongly recommend that a research effort be undertaken to update the six part-load performance curves in the ICES report. These curves are based on data that is at least 25 years old. The list also needs to be expanded to include additional unloading mechanisms such as variable speed drives, units with more than four compressors, and combinations of unloading mechanisms. Moreover, the ACM needs to address very low load efficiency (less than 20% load) that is not currently addressed by the ICES report. Finally, the revised predefined performance curves should be included in the ACM Manual in the same way that the electric chiller default curves are included.

Several options are listed below to obtain part load performance data from currently uncooperative manufacturers:

- Pursue further with the equipment manufacturers voluntary release of part load performance data.
- Require part load data for mechanical equipment compliance with section 112 of the California Energy Efficiency Standards
- Undertake part load testing of representative pieces of unitary HVAC equipment from several manufacturers.

6 RESIDENTIAL AIR CONDITIONER ISSUES

The work presented in this chapter was prepared by Bruce Wilcox of the Berkeley Solar Group.

6.1 Background

California Energy Efficiency Standards for New Residential Buildings (Standards) are a significant influence on the market for air conditioners and heat pumps in the state. Calculations for both Standards development and compliance for air conditioners and heat pumps are based on simple seasonal efficiencies that do not reflect the impact of temperature, humidity and equipment size. Economic calculations for Standards development are based on simple electricity prices that do not include the variation of energy and demand costs with season and time of day. The purpose of this study is to investigate the effect on Standards development and compliance of including these variables.

This is a report on work in progress. It includes example results for the impact of ceiling insulation in Fresno (CTZ 13).

6.2 Approach

Computer simulation is the basis of Standards development activities and most compliance calculations and this study also. In order to include the additional effects cited above, it is necessary to go beyond the capabilities of the California Energy Commission (CEC) certified residential compliance software. CNE, an hourly simulation program derived from the CEC CALRES program, but with enhanced HVAC equipment capabilities is used in this study.

The CEC standard 1761 square foot prototype house has been adapted for use in CNE. The prototype is a 2 story house with equal glazing distribution on each orientation. It was developed to represent average production housing and include major compliance issues such as slab and raised floor and garages.

The HVAC model for the time of use (TOU) analysis includes the varying effects of outdoor and indoor temperature and humidity on cooling capacity and efficiency. The standard CEC internal gains have been modified to have a 20% latent component for use with this model. A standard SEER 10 air conditioning system was modeled using the latest approach to inputs for part load and temperature effects[19,20]

Results are summarized for the standard CEC source energy calculation without TOU effects as a base case. They are also reported for PG&E Time of Use Rate structure. In addition, an hourly file of energy consumption by end use is exported for use in hourly energy and demand cost calculations.

6.3 Results Using Standard CEC Seasonal Efficiencies.

Here we have compared the source energy requirements of a 1,761 sf home in climate zone 13 with R-38 ceiling insulation (the current code requirement) to the same home with R-19 insulation in the roof. Source energy kBtu's for cooling can be converted into kWh of site electricity by dividing by 10.23. Heating source kBtus can be converted to site therms by dividing by 100.

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[19] PG&E equipment testing, Leo Rainer, Davis Energy Group, personal communication, 1998.

[20] Huang, Joe et al, "Residential Equipment Part Load Curves for Use in DOE2, LBNL 42145 Draft, 1998

Table 65: Results Using Standard CEC Seasonal Efficiencies (Source kBtu/sf)

Case	Cooling	Heating	Total
R-19 Ceiling	7.62	11.58	19.20
R-38 Ceiling	6.71	10.71	17.43
Savings	0.91	0.87	1.78

6.4 Results Using Hourly Variable HVAC Efficiency and Capacity.

These results are summarized by PG&E Time of Use Rate structure (TOU):

The summer period is May 1 through October 31.

Summer peak is 12:00 noon to 6:00pm Monday thru Friday (except holidays)

Summer partial-peak is 8:30am to 12:00 noon and 6:00pm to 9:30pm Monday through Friday (except holidays)

Summer off-peak is 9:30pm to 8:30am Monday thru Friday and all day Sat.,Sun. and holidays

The winter period is November 1 through April 30

Winter partial-peak is 8:30am to 9:30pm Monday thru Friday (except holidays)

Winter off-peak is 9:30pm to 8:30am Monday thru Friday (except holidays) and all day Sat., Sun. and holidays

Holidays are New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day (dates that are legally observed).

For use in the hourly simulations, the half hour rate block boundaries were moved up to the previous hour boundary.

Table 66: Results for Base Case with R-38 Ceiling Insulation

Total Electricity, kWh

Month	1	2	3	4	5	6	7	8	9	10	11	12	Annual
On Peak				59	94	236	308	329	190	83			1298
Mid Peak	166	147	170	83	109	204	252	248	136	101	162	169	1948
Off Peak	235	191	180	180	237	279	451	346	286	218	217	239	3059
Total	401	338	350	322	440	719	1010	923	612	402	379	408	6305

Cooling Electricity, kWh

Month	1	2	3	4	5	6	7	8	9	10	11	12	Annual
On Peak				7	43	187	263	273	136	20			928
Mid Peak			6	5	32	130	183	163	53	6			578
Off Peak				7	83	141	289	191	103	14			827
Total			6	19	157	458	734	626	292	41			2333

Overall Peak Demand, kW

Month	1	2	3	4	5	6	7	8	9	10	11	12	Annual
On Peak	0.8	0.8	1.5	2.0	2.8	4.1	4.1	4.2	3.2	1.9	0.8	0.8	4.2
Mid Peak	0.8	0.8	0.7	1.7	3.6	3.8	4.2	4.0	4.0	2.3	0.8	0.8	4.2
Off Peak				1.7	2.4	3.6	3.7	4.0	3.3	2.0			4.0
Monthly	0.8	0.8	1.5	2.0	3.6	4.1	4.2	4.2	4.0	2.3	0.8	0.8	4.2

Cooling Peak Demand, kW

Month	1	2	3	4	5	6	7	8	9	10	11	12	Annual
On Peak				1.7	2.4	3.6	3.7	4.0	3.3	2.0			4.0
Mid Peak			0.9	1.3	2.3	3.5	3.5	3.6	2.5	1.1			3.6
Off Peak				1.1	3.1	3.2	3.6	3.5	3.4	1.7			3.6
Monthly			0.9	1.7	3.1	3.6	3.7	4.0	3.4	2.0			4.0

Table 67: Results for Base Case with R-19 Insulation

Total Electricity, kWh

Month	1	2	3	4	5	6	7	8	9	10	11	12	Annual
On Peak				63	108	266	341	363	210	89			1440
Mid Peak	166	147	172	86	119	219	267	263	142	103	162	169	2016
Off Peak	235	191	180	187	248	300	482	365	301	222	217	239	3166
Total	401	338	352	335	475	785	1090	992	653	413	379	408	6622

Cooling Electricity, kWh

Month	1	2	3	4	5	6	7	8	9	10	11	12	Annual
On Peak				11	57	218	296	307	156	26			1070
Mid Peak			8	8	42	145	198	178	60	8			646
Off Peak				13	93	162	320	210	118	18			933
Total			8	32	192	524	813	695	333	52			2650

Overall Peak Demand, kW

Month	1	2	3	4	5	6	7	8	9	10	11	12	Annual
On Peak	0.8	0.8	1.6	2.2	3.1	4.4	4.4	4.6	3.4	2.0	0.8	0.8	4.6
Mid Peak	0.8	0.8	0.7	2.0	3.9	4.1	4.5	4.4	4.3	2.5	0.8	0.8	4.5
Off Peak				2.0	2.7	4.0	4.1	4.3	3.6	2.3			4.3
Monthly	0.8	0.8	1.6	2.2	3.9	4.4	4.5	4.6	4.3	2.5	0.8	0.8	4.6

Cooling Peak Demand, kW

Month	1	2	3	4	5	6	7	8	9	10	11	12	Annual
On Peak				2.0	2.7	4.0	4.1	4.3	3.6	2.3			4.3
Mid Peak			1.0	1.5	2.5	3.9	3.9	3.9	2.7	1.3			3.9
Off Peak				1.4	3.4	3.5	4.0	3.8	3.7	1.9			4.0
Monthly			1.0	2.0	3.4	4.0	4.1	4.3	3.7	2.3			4.3

6.5 Residential Energy Cost savings Results

The hourly energy results generated by the CNE energy simulation program were paired with energy costs for each hour to develop a comparison of the cost savings afforded by increasing attic insulation under three different energy costing regimes. Heating savings were evaluated for both natural gas (NG) and propane (LPG) fuel sources.

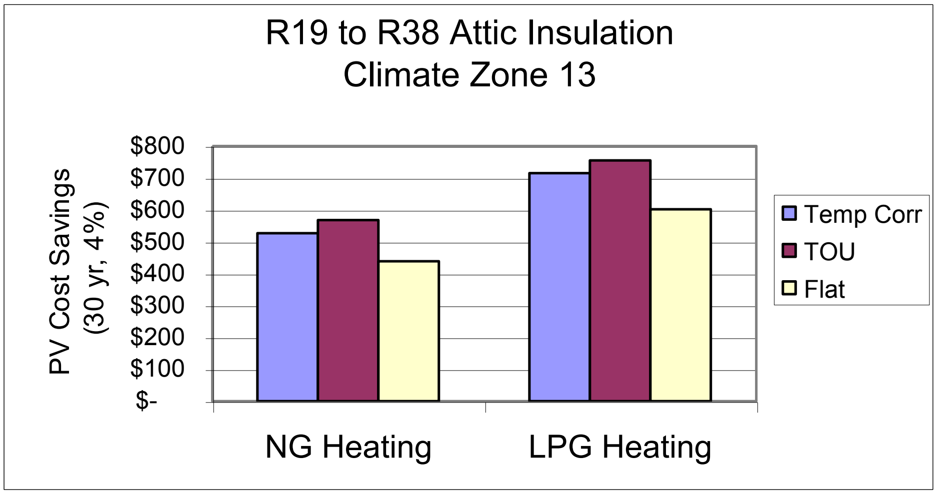

Figure 38: TOU Rate Effects on Attic Insulation Cost Savings

As can be seen from Figure 38, time and temperature dependant rates increase the cost savings available from increased attic insulation as compared to flat energy rates. Attic insulation preferentially reduces air conditioning loads when electricity rates are highest (summer afternoons). Similarly attic insulation reduces heating loads during the winter months when gas or propane rates are higher.

7 APPENDIX - NONRESIDENTIAL ENERGY COST SAVINGS RESULTS