# Time Dependent Valuation of Energy for Developing Building Efficiency Standards

## Summary Report

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# EXECUTIVE SUMMARY

This report examines the feasibility for creating and implementing mechanisms for the time dependent valuation (TDV) of energy in developing Title 24 Standards. California's Title 24 Energy Efficiency Standards for Residential and Nonresidential Buildings regulate the energy performance of building envelopes, lighting, water heating and HVAC systems. Under the Warren-Alquist Act, the legislature charged the California Energy Commission (CEC) 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. The Standards also could influence the rate and characteristics of on-peak and off-peak electric load growth, which are a key concern these days, although mechanisms for doing this have not yet been incorporated into the Standards.

Past development and revisions of the Title 24 Energy Standards were based on electricity and natural gas costs that did not account for seasonal or time-of-use patterns. These energy costs were based upon the annual average price of electricity ($/kWh) or natural gas ($/therm) paid by residential or commercial consumers throughout the state. However, both the price Californians pay for energy and the cost of delivering energy depends upon when and where the energy is needed. This study investigates the feasibility of using a more accurate energy costing analysis for the Standards which accounts for variations in cost related to time of day, seasons, geography and fuel type. The geographical and temporal variabilities in delivered energy costs are due to differences in commodity prices (electricity prices are higher in summer than winter, natural gas and propane prices are higher in the winter than summer) and the costs of the electrical transmission and distribution system which are driven by the need for capacity in high usage times of the year.

Cost-effectiveness criteria in the Standards that place a higher value on energy savings during the high cost times of the year, and are more closely tied to the actual variations in energy costs, could lead to Title 24 amendments that would, in turn, encourage the design and construction of buildings which reduce the peak demands on the energy system in California. Over time, this would lead to significant cost savings and improved reliability for utilities, customers and society at large.

***Economic Model***

Rates, the published tariffs that utilities charge customers, do not fully capture temporal and geographic variations in energy costs. Since rates are usually the same across an entire utility system, geographic variation in costs within a utility service territory is not represented. Utility rates also embody regulatory, marketing and billing strategies. Utility rates and rate structures can change over time, sometimes as frequently as every few years. Such influences mean that rate-based price signals are less than ideal for optimizing resource efficiency in building design. On the other hand, building standards that are not based on rates could require building energy efficiency improvements that do not result in comparable reductions in energy bills, and therefore may not be cost-effective to building investors and bill payers. Since rates are not an ideal basis for setting the cost-effectiveness foundations of the energy Standards, this project has sought to develop a comparable economic basis that reflects the realities of the utility system costs and operations over a long time frame. This improved energy valuation could lead to energy Standards that send accurate signals to building designers about cost-effective energy efficient building designs. This has led to a TDV economic model for the societal cost of energy on an hourly basis that realistically reflects the geographic and temporal variations in the value of energy.

The societal costs of energy in our TDV model are the summation of:

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

- Commodity costs - This is the cost of the electricity from the generators (owners of power plants) as sold on the California Power Exchange (PX) or the cost of natural gas from the wellhead. Hourly costs for typical weeks for each month have been generated by the CEC. These hourly costs are adjusted for each year into the future based upon forecasts of costs of fuel (natural gas) used by new electrical generating plants.
- Marginal transportation and distribution (T&D) costs - This is the incremental cost of the delivery system to supply increased consumption of energy. This would include the costs associated with increased capacity of pipelines and storage for the natural gas system, or the wires, transformers and substations for the electricity delivery system. These marginal costs do not contain fixed costs (such as interest on capital) nor do they contain company profit or return to investors.
- Fixed utility costs - these include all of the other costs that are reflected in customers' utility bills, such as taxes, interest on capital, and billing and meter reading costs. In our model, these are applied as a flat $/kWh or $/therm across all hours to scale commodity and T&D costs up to the overall revenue requirements of current utility rates. A major advantage of this approach is that equitable comparisons can be made across fuels between electricity and natural gas (for which marginal costs are a much higher percentage of revenue requirements) and propane (for which marginal cost data is unavailable).
- Environmental externalities - these have been limited to an economic valuation of air emissions related to combustion only and is based upon least cost mitigation (emission credits). The economic value of these credits is highly influenced by public policy on the acceptable level of air emissions. This valuation is substantially lower than the valuation contained in the CEC's 1994 Energy Report.
- A fixed adder that brings the cost of energy up to real (inflation adjusted) values that were used by the CEC in analyzing the cost-effectiveness of the 1992 Standards. This adder maintains stability in the overall stringency of the standards.

Natural gas costs included in our TDV approach are derived from data on marginal and fixed costs for natural gas delivery in California, and on CEC forecasts of future gas costs.

Propane costs were not considered separately when the 1992 Standards were developed, but they are treated separately from natural gas in our model. We have gathered data on current and forecast propane costs, and we also have developed adders for externalities, similar to those proposed for natural gas costs.

The economic model that we have developed provides a rational basis for calculating the time dependent valuation of energy use and energy savings. Consequently, we refer to this methodology as TDV, or time dependent valuation.

### *Consequences of TDV on the Standards and Compliance Methods*

In the 1990 cost-effectiveness evaluation of the 1992 Standards, the cost differential between electricity and natural gas (or propane) was 4.1 to 1 for residential standards and 4.7 to 1 for the non-residential standards. For the performance method (computer simulation) of Standards compliance, the units of comparison were in terms of source energy. It was assumed that 1 unit of delivered natural gas or propane was equal to 1 source energy unit whereas 1 unit of delivered electricity was equivalent to 3 units of source energy. Thus there has been an inconstancy between how measures were evaluated for developing the prescriptive standards and how trade-offs are allowed through the alternative compliance (performance) method. We are recommending that time dependent valuations of all energy sources be consistently applied in the Standards development process and in the application of the alternative compliance methods. Thus the TDV factors for electricity, natural gas and propane would have to be embedded in both residential and non-residential Title 24 compliance software.

The impacts of a time dependent valuation (TDV) of energy on the cost-effectiveness of the Standards were tested by applying the candidate costing methods (developed with our economic model) to hourly energy simulations of six prototype commercial buildings and one residential building prototype for a range of efficiency measures. This required developing not only energy costs for every hour of the year, but also the creation of energy models of residential and commercial buildings that accurately described energy consumption for each hour of the year.

This exercise helped identify shortcomings in current residential and non-residential energy models used to show Standards compliance under the computer simulation-based performance approach. Some of these shortcomings include:

- Currently the efficiencies of unitary heat pumps and air conditioners are treated as constant in the residential compliance software. To better reflect reality, the software should vary efficiency as a function of ambient temperature and the amount of cooling or heating required.
- Currently the efficiency of unitary heat pumps and air conditioners in the nonresidential compliance software is a function of a default efficiency curve. Using a single efficiency curve for all equipment types, however, does not reflect the real differences between HVAC products. To give credit for new HVAC equipment technologies that respond more efficiently to temperature and load, a library of technology specific curves should be developed for use in the nonresidential compliance software.
- Given the importance of HVAC duct efficiency to overall energy consumption of the HVAC systems, a robust model is needed to calculate the savings from well-sealed and insulated ducts. These savings vary hour by hour as temperature and sun conditions change.
- Other time varying assumptions about building operation must be set to accurately reflect reality. Examples include schedules for hot water usage and thermostat operation, building occupancy patterns, etc.

Our analysis of the TDV methodology on various building types and measures helped develop the following insights about the impact of different costing strategies.

For residential energy efficiency measures:

- 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 value of residential roof insulation was increased because this insulation helps reduce cooling loads in the summer when the cost of electricity is highest and reduces heating loads in the winter when the cost of gas is highest.
- A greater value was assigned to reducing the solar heat gain coefficient (SHGC) of glazing because of the greater cost assigned to peak cooling loads.
- Low-e glazing with lower SHGC and lower U-factor fared better because it reduces heating loads during times when gas prices are highest and reduces cooling loads when electricity prices are highest.
- The current residential code compliance software treats air conditioner and heat pump efficiency as constant, regardless of load and outside air temperature. A simulation model of air conditioner and heat pump efficiency that accounts for ambient temperature and load on an hourly basis yields markedly different results than a constant efficiency model, when applied in a cost-effectiveness analysis that uses time-varying rates.
- 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. Consequently, in our economic model, a "tail" of increasing electrical costs as temperatures drop below 30°F has been added to T&D costs to address electrical peak loads that are predicted in absence of an increased valuation for the coldest hours.
- The energy costs of switching from gas heating to electric heat pumps is higher under TDV costing than the traditional flat costing because electricity is allocated high costs during cold

weather. This costing strategy appears to provide the appropriate signal to discourage electric heating.

For nonresidential energy efficiency measures:

- Time dependent valuation (TDV) moderately increases the cost savings value of air conditioning efficiency, compared to flat rate costing. (Unfortunately, part load efficiency figures for unitary air conditioning equipment are not available; such data would give greater precision to these results.)
- Replacing gas heat with electric resistance heat results in TDV building energy costs that re as high or greater than the costs under the current flat costing system.
- TDV substantially enhances the cost effectiveness of thermal energy storage and gas cooling.
- TDV has a small but positive impact on the cost savings from daylighting and low-e windows.
- The impact of TDV on the cost savings from reduced lighting power density is dependent upon the building occupancy (for example, office and retail occupancies show increased cost savings from TDV).

For all measures addressed by the Standards

- Caution should be applied to relaxing standards on envelope requirements in exchange for technologies, such as thermal energy storage, which can be more readily replaced or disabled. One method to do this would be to use the present value of the energy savings over the useful life of the technology rather than to assume that all measures have the same useful lives, as currently is done in the Standards.
- Efficiency requirements for buildings should differ depending upon the heating and cooling sources used (electricity, natural gas and propane), because the costs for these sources differ significantly.

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

- A "flat" efficiency model based solely on SEER (current Standards) underestimates the energy consumption during peak cooling conditions - conditions that are coincident with higher electricity costs. The performance simulation tools for the residential standards should be updated so that air conditioner efficiency is a function of ambient air temperature.
- Heat pumps are less efficient during times of peak loads and thus will consume more energy during times of peak heating loads than is currently modeled with a flat HSPF(Heating Seasonal Performance Factor) model.

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

- Revisit the base case HVAC equipment assumptions in light of their performance curves and the available equipment on the market. It is probably not advisable to use the least efficient equipment (in terms of time-varying efficiency) as the basecase. Rather, we recommend equipment with median performance characteristics, in order to encourage users to specify median or better performing equipment.
- 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.
- Revisit the calculation procedure listed in the ACM Manual for generating an EIR (energy input ratio) from the listed SEER (seasonal energy efficiency ratio) for air conditioning equipment having a capacity less than 65,000 Btu/h.

- Investigate a heat pump performance model that develops a methodology for determining heat pump capacity in the model and includes the energy consumption of heat pump resistance elements when heat pump capacity is unable to meet heating loads.
- Refine the domestic hot water loads model based upon loads from a population of homes, a tank temperature model based upon draw down and recovery time and a standing losses calculation based upon tank temperature.
- Revisit schedules for occupancy, ventilation, thermostats, lighting, etc. as these assumptions are more critical under the TDV method than under the earlier Standards.
- Collect field data on time-of-use characteristics of efficiency measures such as occupancy sensors.
- Refine methodology to account for persistence and life of measures and strategies. E.g. consider a lower valuation for changeable measures such as TES (thermal energy storage) control strategies than for persistent measures such as dual pane glazing.

### *General Conclusions*

The project team concluded that a time dependent valuation, with adjustments to match utility revenue requirements and a costing of externalities, provides a rational basis for developing new efficiency standards (as opposed to the traditional flat rate basis). Energy Standards revised under this savings valuation scheme would provide better guidance on the design of buildings that reduce peak loads and would improve the overall efficiency of the state's energy delivery systems. This would likely result in a higher energy system load factor and associated lower energy costs for consumers. If the Commission decides to move forward to reevaluate the cost-effectiveness of the Standards under this new valuation strategy, then the various stakeholders (builders, environmental groups, energy companies, etc.) need to be informed and their ideas incorporated into the revision process. The utility sponsors of this work intend to assist in this process.

To assist interested parties in evaluating the repercussions of this energy valuation format on the cost-effectiveness of a variety of energy efficiency measures, the following tools have been developed and are available to interested parties:

- Versions of alternative compliance software for both the residential Standard (MicroPass) and the nonresidential Standard (Energy Pro) that will export hourly energy consumption data for hourly time varying energy cost evaluations. The "research version for TDV" of Energy Pro has revised equipment efficiency curves that more closely match average (for the budget building) and 15th percentile (for the proposed building defaults) capacity and efficiency performance with respect to ambient temperature.
- Residential and nonresidential spreadsheets that import the hourly energy consumption data from the appropriate compliance software and multiply this data by TDV costs for electricity, natural gas and propane. In addition the residential spreadsheet will apply correction factors for duct efficiency and HVAC equipment efficiency in response to load and ambient conditions. Separate costs for residential and nonresidential energy consumption are given in this spreadsheet to account for different costs associated with residential versus nonresidential energy as well as different analysis periods for these building types. When compared against a prescriptive base case, this will yield the present value of the energy savings of a given measure or building design.

# 1. INTRODUCTION

This is the Summary Report for the Time Dependent Valuationof Energy Standards Project (the TDV Project), jointly funded by the California Energy Commission and Pacific Gas & Electric Co., with participation and support from Southern California Edison. The PG&E project managers are Pat Eilert, Gary Fernstrom, Jennifer Barnes and Misti Bruceri. The project is being lead by Douglas Mahone and Jon McHugh of the HESCHONG MAHONE GROUP. Team members include Brian Horii, Snuller Price, Dan Engel and Jennifer Martin of Energy & Environmental Economics, Charles Eley, Randy Karels and Jeff Stein of Eley Associates, and Bruce Wilcox of the Berkeley Solar Group. This summary builds on work performed in an earlier phase of the project, described in the report, *"Dollar-Based Performance Standards for Building Energy Efficiency, Final Report"*, March 25, 1999, submitted to PG&E by the same team.

This project examines the feasibility and implications of changing the economic basis used by the California Energy Commission (CEC) for setting the requirements of the building energy efficiency standards, known as the Title 24 Standards. The enabling legislation for the Title 24 Standards 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[2]. This project has been 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. The resulting methodology is called "time dependent valuation" or TDV for short.

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 designers of new building with 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 [3]units in areas where peak demand is not a problem, or
3) Give greater recognition to gas cooling (than do the current standards) because it displaces high cost on-peak electrical power. This recognition of area and time differences in the standards could ultimately 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.

[2] 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 and regulatory fees. Prices are influenced by costs, but many other factors enter into the setting of prices, such as market conditions, regulatory constraints, customer preferences, etc.

[3] Note: SEER, or Seasonal Energy Efficiency Ratio, is a metric of HVAC equipment efficiency that is typically applied to unit with capacities of 5 tons or less. It purports to describe an average efficiency for a given unit when operated through out a cooling season. In practice, it is less descriptive of the actual performance of equipment under hot, dry temperature conditions which are typical of most of California. The EER, or Energy Efficiency Ratio, is a more useful metric of performance for this purpose.

A revised set of Title 24 Standards that better optimized buildings' energy usage by time of use, under the TDV methodology, would likely favor efficiency measures with better time-of-use characteristics, such as:

- Higher efficiency air conditioners – make better use of on-peak power
- Improved glazing (low-e, low U-factor) – reduce peak heating and cooling loads
- 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** –to allow more accurate TDV economics, and a better assessment of the wisdom of changing the Standards
- **Collect data on average and marginal costs** to provide a better understanding of the time and geography variations
- **Describe possible changes to Title 24 procedures** to 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** to provide a technical basis for crediting energy savings for these systems under time-of-use based Standards
- **Estimate potential implications of Title 24 changes** to provide a preliminary assessment of the implications of a new basis for the Standards

# 2. TIME DEPENDENT VALUATION (TDV) GENERAL FORMULATION

The same basic approach is used to develop the lifecycle TDV values for each of the three fuels affected by the standards; electricity, natural gas, and propane. In each case, the TDV approach makes a number of changes from the existing values used as the basis of the Title 24 Building Standards. Rather than a single value per quantity saved of electricity, natural gas, or propane regardless of time of year or location, this valuation has variation by month and area.

The underlying concept in these values is to reflect the underlying 'shape' of the commodity price and environmental externalities, and the 'level' of end use rates. In addition, an adder is included so that when the total level of TDV lifecycle values is equivalent to the total cost of the flat valuation of the existing standard.

A general formula for each of the three TDV values is as follows:

$$TDV_{hour} = PV\left\lfloor Marginal\ Cost_{hour,year} + Rate\ Adder_{year} + Emissions\ Adder_{hour} \right\rfloor + 1992\ Adder$$

where

$$Rate\ Adder_{year} = Average\ Annual\ Rate - \frac{\sum_{hour} Marginal\ Cost_{hour,year} * Consumption_{hour}}{\sum_{hour} Consumption}$$

$$1992\ Adder = \frac{Lifecycle\ value\ so\ that\ weighted\ sum\ of\ TDV\ present\ value\ equals}{current\ present\ value\ standard\ developed\ for\ the\ 1002\ Efficiency\ Standards}$$

In comparing the three energy sources (electricity, natural gas and propane) the following differences should be noted:

- The emissions adder is time varying for electricity only. This is due to differences in power plant efficiency as they are dispatched. More expensive (peaking) plants are less efficient and emit more pollutants per kWh than plants operating off-peak. In contrast combustion of natural gas and propane is assumed to emit the same level of pollutants per therm of fuel regardless of time of day.
- When values for energy sources were developed for the 1992 standards, the fuel costing was based upon natural gas. Since there was no evaluation of propane costs for the 1992 standards, no adjustment back to 1992 values is needed for propane. Thus, propane TDV costs do not contain a "Adder to 1992 Value" component.

# 3. ELECTRICITY COSTING

The societal electricity costs used to evaluate the TDV cost effectiveness of energy efficiency measures for inclusion in the building efficiency standards are a combination of:

- **Commodity costs** - the cost of electrical generation as delivered to the California Power Exchange (PX). These costs are modeled as a time series based upon historical prices on the power exchange with an adder to account for the costs of bringing new generators into the PX. (Note that these costs are modeled as time series and are not directly correlated to temperature the way transmission and distribution costs are - the prices on the power market are affected by more influences than just regional loads.)
- **Transmission and Distribution marginal costs** - this is the cost of additional transmission and distribution capacity to handle peak loads. These peak loads are correlated to high temperatures and the costs are allocated from the total costs to hourly costs by peak capacity allocation factors (described in more detail later in Section 10.1.2). Given the timing and load factor of the residential versus non-residential loads, and the costs associated with equipment serving residential versus non-residential loads, these costs are different for the two building types.
- **Fixed costs** - these include all the other costs reflected in customers' utility bills, such as taxes, billing and meter reading, interest on capital, company profit and return to investors. These fixed costs are the difference between the total revenues collected by the electric utilities and the totals of the commodity, transmission and distribution marginal costs. These fixed costs are applied as a flat adder i.e. the fixed costs are the same $/kWh regardless of time of day, day of week or season of year. Note that this value is different for residential and non-residential buildings and differs by region so that costs are scaled up to a statewide average of revenues.
- **Environmental externalities** - these costs are additional societal costs not currently extracted by environmental protection or other regulatory programs (which are already reflected in the fixed cost component). The externalities estimation is a "least cost" valuation of externalities based upon emission trading credits. The analysis here assumes that all marginal generation is gas fired, either a natural gas combustion turbine or a combined cycle turbine and that the main emissions of economic value are NOx and $CO_2$.
- **1992 Adder** - This adder brings the overall cost of TDV electricity up to the same total value of electricity costs used to develop the cost-effectiveness of the 1992 standards. This serves to keep the overall stringency of any proposed changes to the Title 24 Standards comparable in stringency to the 1992 Standards.

By combining all of the above factors we have a time dependent valuation of electricity for a given hour i, $ETDV_i$, as:

$$ETDV_i = \begin{array}{c}(Commodity\ Cost_i)+(T\ \&\ D\ Marginal\ Cost \times PCAF_i)+(Fixed\ \ Cost\ \ Adder)+ \\ (Emission\ Externalit\,y_i)+(Adder\ to\ 1992\ level)\end{array}$$

As indicated by the subscripts, the commodity cost, T&D costs and externalities are time varying. The fixed cost adder and the adder to the 1992 level are both constant across all hours of the year.

A detailed description of the cost components for TDV propane costing is found in Section 10.1.

The following table summarizes the energy costs and the additional costs allocated to environmental externalities and to maintain stability of the Standards.

**Table 1:Summary Statistics on Electricity TDV Costing**

| TDV Lifecycle Cost Components $/kWh | Zone | Oakland | | China Lake | | Fresno | | Long Beach | | Shasta | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **TDV Component** | Class | Res | Com | Res | Com | Res | Com | Res | Com | Res | Com |
| **Commodity Cost** | Min | $0.03 | $0.02 | $0.03 | $0.02 | $0.03 | $0.02 | $0.03 | $0.02 | $0.03 | $0.02 |
| | Avg | $0.75 | $0.45 | $0.74 | $0.45 | $0.75 | $0.45 | $0.74 | $0.45 | $0.75 | $0.45 |
| | Max | $3.14 | $1.91 | $3.13 | $1.90 | $3.14 | $1.91 | $3.13 | $1.90 | $3.14 | $1.91 |
| **T&D Cost** | Min | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | Avg | $0.21 | $0.14 | $0.37 | $0.17 | $0.32 | $0.19 | $0.13 | $0.07 | $0.47 | $0.31 |
| | Max | $95.18 | $61.56 | 129.80 | $82.72 | 150.01 | $97.02 | $73.51 | $45.50 | 637.40 | 412.26 |
| **Rate Adder** | Flat | $1.03 | $0.28 | $0.74 | $0.32 | $0.91 | $0.23 | $1.20 | $0.55 | $0.76 | $0.11 |
| **1992 Standard Adder** | Flat | $0.48 | $0.43 | $0.60 | $0.37 | $0.48 | $0.43 | $0.38 | $0.23 | $0.48 | $0.43 |
| **Environmental Adder** | Min | $0.11 | $0.06 | $0.11 | $0.06 | $0.11 | $0.06 | $0.11 | $0.06 | $0.11 | $0.06 |
| | Avg | $0.14 | $0.09 | $0.14 | $0.09 | $0.14 | $0.09 | $0.14 | $0.09 | $0.14 | $0.09 |
| | Max | $0.24 | $0.14 | $0.24 | $0.14 | $0.24 | $0.14 | $0.24 | $0.14 | $0.24 | $0.14 |
| **Total TDV** | Min | $1.67 | $0.82 | $1.51 | $0.79 | $1.56 | $0.76 | $1.76 | $0.89 | $1.41 | $0.65 |
| | Avg | $2.60 | $1.39 | $2.60 | $1.39 | $2.60 | $1.39 | $2.60 | $1.39 | $2.60 | $1.39 |
| | Max | $97.66 | $62.87 | 132.26 | $84.08 | 152.37 | $98.27 | $76.07 | $46.87 | 639.56 | 413.36 |

# 4. NATURAL GAS COSTING

Compared to electricity, natural gas transmission and distribution marginal costs are relatively low. Gas pressure can be increased to increase capacity of gas transmission and distribution as well as storage facilities. Since the T&D costs are flat these can be combined with the flat costs associated with overhead and profit so that the cost calculation is easier. By subtracting the annual fuel cost from the annual gas rate, one is able to obtain the combined flat cost for T&D as well as gas utility fixed costs. To obtain the total time dependent values of natural gas, the following components of gas costs are added to the T&D costs and the utility fixed costs:

- Monthly gas costs as described in Section 10.3.1
- A flat (constant with respect to time of day or year) adder so the total value of natural gas matches the real value of natural gas used to develop the 1992 California efficiency standards. This adder helps maintain the overall stringency and stability of the standards.
- Externality costs as described in the preceding section

A detailed description of the cost components for TDV natural gas costing is found in Section 10.3

Thus the TDV natural gas values are computed with the following equation:

$$TDV\ Value\ \{month, year\} = \begin{array}{c} Monthly\ Fuel\ Cost\{month, year\} + \\ Emission\ Externality\{year\} + Adder\ to\ 1992\ Value + \\ \left(Annual\ Ave.Total\ Rate\{year\} - Annual\ Ave.FuelCost\{year\}\right) \end{array}$$

The following table summarizes the components of time dependent costs that have been developed for natural gas.

**Table 2: Summary Statistics for Natural Gas TDV Costs**

| TDV Lifecycle Cost Components $/MMBtu | Zone | PG&E | | Socal Gas | | SDG&E | |
|---|---|---|---|---|---|---|---|
| **TDV Component** | Class | Res | Com | Res | Com | Res | Com |
| **Commodity Cost** | Min | $56.02 | $31.46 | $53.26 | $29.62 | $53.01 | $29.48 |
| | Avg | $60.03 | $33.41 | $59.91 | $32.91 | $59.78 | $32.90 |
| | Max | $63.44 | $35.63 | $67.77 | $37.69 | $70.31 | $39.11 |
| **Rate Adder** | Flat | $62.55 | $40.79 | $70.52 | $25.22 | $70.54 | $37.03 |
| **1992 Standard Adder** | Flat | $53.73 | $5.04 | $45.88 | $21.12 | $45.98 | $9.31 |
| **Environmental Adder** | Flat | $11.90 | $7.25 | $11.90 | $7.25 | $11.90 | $7.25 |
| **Total TDV** | Min | $184.19 | $84.55 | $181.56 | $83.20 | $181.43 | $83.07 |
| | Avg | $188.20 | $86.49 | $188.20 | $86.49 | $188.20 | $86.49 |
| | Max | $191.61 | $88.71 | $196.07 | $91.27 | $198.73 | $92.69 |

# 5. PROPANE COSTING

This section describes the derivation of a forecast of propane prices by month for residential and commercial customers for use in developing the new revision of the building standards.

Total propane costs for this valuation are the sum of:

- Wholesale prices - projected from forecasts of crude oil price
- Rate adder - the difference between wholesale and retail prices.
- Environmental externalities - the same valuation for NOx and $CO_2$, that was used for applying externalities values to natural gas and electricity consumption, is applied to the expected emission of these pollutants from propane combustion.

There is no adder to bring the propane valuation up to levels used to develop the 1992 energy efficiency standards, because propane was not specifically costed in the development of the 1992 standards.

A detailed description of the cost components for TDV propane costing is found in Section 10.4

In the current building standards, conservation of propane is treated as having the same value as conservation of natural gas. However, propane and natural gas have very different prices. Propane costs roughly twice as much per MMBtu as natural gas. In addition, the relative values between fuels and electricity were different for development of the standards and the values used in the Alternative Compliance Method (ACM) software. If implemented in its entirety, the TDV method would be apply specific time varying costs to each energy source (electricity, natural gas and propane) and the same values used in the development of standards would also be applied to the Alternative Compliance Method (ACM) software.

The following table contains the present value of propane conservation for residential and commercial usage. All values are given in 2001 dollars. The existing standards use a 15-year present value for commercial buildings, and a 30-year present value of residential buildings. Present value has been calculated with a 3% real discount rate[4].

[4] This is the same assumption as the current standard. See Summary of Cost-Effectiveness, March 29, 1990, Jon Leber P.E., California Energy Commission.

**Table 3: Summary Statistics for Propane TDV Costs**

| TDV Lifecycle Cost Components $/MMBtu | Class | Res | Com |
|---|---|---|---|
| **Commodity** | Min | $115.87 | $50.93 |
| | Avg | $128.95 | $53.97 |
| | Max | $137.89 | $58.51 |
| **Rate Adder** | Flat | $117.42 | $82.96 |
| **Environment** | Flat | $14.08 | $8.58 |
| **Total TDV** | Min | $247.38 | $142.47 |
| | Avg | $260.46 | $145.51 |
| | Max | $269.39 | $150.04 |

# 6. ECONOMIC ANALYSIS OF EFFICIENCY MEASURES

We have developed TDV costs for electricity that vary by geography, time of day and outside temperature, and for natural gas and propane that vary by season and region. This economic analysis tries to answer several questions about how various energy costing schemes effect the cost savings of various building efficiency measures. It seeks to quantify the cost impacts the proposed TDV costing as compared with the previous flat costing (variation with respect to time) strategy:

Societal electricity, natural gas and propane costs have been developed for 6 geographic regions - Mountains, Bay Area, Central Valley, Los Angeles, High Desert, and San Diego. These geographic regions represent the range of California climates and contain the bulk of the State's population. This summary reports on only the results for the Central Valley (Fresno). For more information, the reader is referred to the *Final Report: Dollar-Based Performance Standards for Building Energy Efficiency*[5]. That report evaluated several energy costing scenarios - the strategy selected here for time dependent valuation was described in this previous report as the " temperature correlated CEC original" energy costing[6].

The existing Standards were developed with 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. 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. Propane unit costs are now included in our calculations, and the same methodology is applied; here we have added the identical externality costs to propane as are applied to natural gas. The electricity data comes from the CEC forecasting division[7]. The natural gas data comes from the Energy Information Administration[8]. The Propane cost data comes from the team's analysis of rates performed for this project. All prices are brought to year 2002 values using the CEC developed deflators (inflation adjustment factors).

The following comparison of measures in sections 7 and 8 below makes use a preliminary economic model that did not include a time dependent valuation of externalities. These results are indicative of the impact that a TDV costing of energy would have on the cost-effectiveness of a variety of residential and nonresidential energy efficiency measures. We expect that the final TDV costing numbers will increase slightly the importance of the timing of the energy impacts of different measures.

Table 4 compares the average societal energy costs developed under the draft TDV methodology for a Central Valley location. It breaks out the components of those costs for the three fuels of interest, and allows a general comparison of the differences in costs proposed for TDV analysis. The actual hourly valuation of energy costs (especially electricity) are, of course, much more variable.

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[5] **Dollar-Based Performance Standards for Building Energy Efficiency**, Final Report, March 25, 1999, prepared for Gary Fernstrom, Pacific Gas & Electric Company by the Heschong Mahone Group et al. For a copy, contact the authors at info@h-m-g.com.

[6] Note that there has been a teminology change. The original research referred to "dollar-based standards." Upon completion of the first phase of the project, it was decided that "time dependent valuation" of energy savings was a more descriptive term.

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

[8] **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

**Table 4: Components of Average Societal Costs of Energy Consumed in the Central Valley**

| | Residential 30 yr PV | | | Non-residential 15 yr PV | | |
|---|---|---|---|---|---|---|
| PV [9]Costs | Elec $/kWh | Nat Gas $/MMBtu | Propane $/MMBtu | Elec $/kWh | Nat Gas $/MMBtu | Propane $/MMBtu |
| Marginal | $1.07 | $60.03 | $128.95 | $0.65 | $33.41 | $53.97 |
| Fixed | $1.39 | $116.27 | $117.42 | $0.66 | $45.84 | $82.96 |
| Externality | $0.14 | $11.90 | $14.08 | $0.09 | $7.25 | $8.58 |
| Total Societal | $2.60 | $188.20 | $260.46 | $1.39 | $86.49 | $145.51 |

These final time dependent values for energy costs are contained in spreadsheets that are available from the project team to interested parties[10]. The spreadsheets will process the hourly outputs from either the residential or nonresidential Alternative Compliance Method software and apply hourly energy costs, yielding present valued energy costs for each annual simulation. This format will allow members of the public, including various stakeholders, to directly identify the impact of this costing strategy on any measure that can be modeled using the Alternative Compliance Method software.

[9] PV – costs are converted to present value over the indicated time period

[10] These spreadsheets can be downloaded from the HESCHONG MAHONE GROUP website: http://www.h-m-g.com.

# 7. NONRESIDENTIAL ENERGY CODE ISSUES

This section explores the implications of using a TDV methodology as the basis for setting and implementing the nonresidential building energy efficiency standards. In addition to adopting the TDV methodology for setting the economic basis of the Standards, the CEC would also have to make enhancements and adjustments to the measures required by the Standards, and to the compliance tools and methods used to meet the requirements.

## 7.1 Commercial Building Efficiency Cost Savings Analysis

An analysis was done to demonstrate how the proposed TDV methodology would impact the energy cost savings of efficiency measures, compared to the way that savings are currently valued under the existing Standards. This analysis ran a series of buildings and efficiency measures through DOE-2 simulations, and applied hourly TDV energy costs to calculate the savings of measures (compared to the Title 24 baseline).

Nine building envelope or equipment configurations which impact energy performance (plus a base case configuration) 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. The following subsection discusses the calculation method that was used for this analysis. Section 7.1.2 explains the buildings and measures modeled and section 7.1.3 shows the results of the simulations.

### *7.1.1 ACM Manual Changes*

The TDV methodology, if adopted by the CEC, will have to be implemented for users of the energy simulation software that is used under the performance method of compliance. The current compliance software essentially applies a flat valuation to energy savings (i.e. there is no difference in the valuation of savings by time or by region). In practice, this is actually done using source energy as the measure of comparison, rather than any cost valuation methodology. Under a TDV basis, both the development of the Standard and its implementation in the performance method will use time varying costs, and will have to give comparable results. The rules for using the performance method are specified in the Commission's *ACM Manual,* which will have to be modified to reflect the TDV methodology.

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 to then compare the two results. The new procedure would be to compute energy costs for a standard building and the proposed building, and to compare the two. Thus, at a minimum, the only changes that are required are:

- To replace Table 1-B Source Energy Conversion Rates with time varying energy costs that are representative of the societal costs of different energy sources.
- 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 also be considered. These are presented below. The numbering in the headings refers to section numbers in the *ACM Approval Manual*.

### ACM 2.3.2 Occupancy Lighting

Currently, lighting controls are accounted for simply 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, which are likely to be 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 reducing the lighting power density. A better option for daylighting controls is to use the DAYLIGHTING function in DOE-2.

### ACM 2.3.3 Occupancy Schedules

Currently only three schedule types are used in the ACM: nonresidential, residential, and hotel function. So the energy cost savings for buildings with diverse occupancy schedules can be modeled more accurately, it may be advisable to expand this list. For example, currently a theater is modeled as a typical non-residential occupancy (i.e. 9-5 weekdays), but theaters are typically used primarily in the evenings when energy prices are lower. Classrooms are also modeled as typical 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.

### ACM 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, under TDV, 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 the DOE-2 building energy simulation program (the calculation engine of the Energy Pro alternative compliance method software) 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

The ACM Manual provides for developing alternative compliance methods for these kinds of additional modeling capabilities. Interested parties have the opportunity to develop and propose calculation methods or simulation capabilities to credit additional technologies under the Standards. Perhaps with the adoption of a TDV methodology, there will be greater incentive for third parties to develop these kinds of additional capabilities and credits.

#### ACM 2.4.2.6 Equipment Performance Curves except Electric Chillers

The performance of HVAC equipment changes under varying temperature conditions, both in terms of effective capacity and of part-load efficiency. The current compliance software does not distinguish between the performance of different kinds of HVAC systems, nor does it distinguish changing performance by time of use. The ACM Manual requires that the reference design and the proposed design use the packaged HVAC 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 HVAC system's unloading mechanism (hot gas bypass, suction valve-one compressor, etc). This would allow the Standard to make meaningful distinctions between the efficiency characteristics of different classes of HVAC systems. Especially, it would mean that equipment that is more efficient under peak temperature conditions (very high or very low ambient temperatures) would be given greater credit under the Standards than equipment with poor peak efficiency.

The simulation of air conditioning makes use of the defined system efficiency and adjusts the hour by hour efficiency depending upon ambient and return temperature as well at part load conditions. These adjustments are based upon empirical curve fits of normalized equipment performance to the conditions described in Table 5. The energy input ratio (EIR) is the ratio of electricity input into the air conditioner or heat pump (not including the supply fan) to the heating or cooling produced. The EIR can be thought of as the inverse of the COP (coefficient of performance). These curve fits normalize actual capacity and energy consumption to the performance at ARI rating conditions, fully loaded and with the air temperatures as shown in Table 6.

**Table 5:Adjustment Factors for Cooling and Heating Performance at Off-Design Conditions**

| Curve Name | Description | |
|---|---|---|
| COOL-CAP-FT | Normalized cooling capacity as a function of dry and wet bulb temperatures | CAP = f ( ambient drybulb temp, entering coil wetbulb temp) |
| COOL-EIR-FT | Normalized cooling energy input ratio as a function of dry and wet bulb temperatures | EIR = f ( ambient drybulb temp, entering coil wetbulb temp) |
| COOL-EIR-FPLR | Normalized cooling energy input ratio as a function of part load | EIR = f ( Part Load Ratio) |
| HEAT-CAP-FT | Normalized heating capacity as a function of outside dry bulb temperatures | CAP = f ( ambient drybulb temp, entering coil drybulb temp) |
| HEAT-EIR-FT | Normalized heating energy input ratio as a function of outside dry bulb temperatures | EIR = f ( ambient drybulb temp, entering coil drybulb temp) |
| HEAT-EIR-FPLR | Normalized heating energy input ratio as a function of part load | EIR = f ( Part Load Ratio) |

We initially investigated the technologies for 150 different rooftop package units from several manufacturers and tried to draw conclusions between the presence of a particular technology and unit performance. Performance data is given in terms of energy input and capacity at off-rated temperatures. No data was available on part load performance outside of the SEER (seasonal energy efficiency ratio). Although qualitative correlations could be made, there were no statistically robust methods of predicting an actual performance curve based on the data available. Systems which look very similar in the catalogs occasionally had widely divergent performance.

Since we were unable to develop a performance mapping relative to technology type, we developed a set of capacity and energy input ratio adjustment curves based upon: 1) the entire sample of equipment 2) the bottom 15% of performers when temperatures diverged from the ARI conditions. The first set of curves would be applied to the base (or budget) case. The second set of curves would be applied to the proposed building unless the designer entered the performance characteristics of the piece of equipment they were specifying.

**Table 6: ARI Rating Conditions for Air-Conditioners and Heat Pumps**

| Equipment | Ambient air temperature (°F) | Air temperature entering coil (°F) |
|---|---|---|
| Air conditioners | 95° drybulb | 80° drybulb,<br>67° wetbulb |
| Heat Pumps | 47° drybulb | 70° drybulb |

Equipment with capacities less than 65,000 Btu/h are required only to publish a SEER (seasonal energy efficiency ratio). In section 2.4.2.7 "Cooling Efficiency of DOE Covered Air Conditioners" of the 1998 Nonresidential ACM Manual there is a calculation method for calculating the EER from the SEER. This method must be revisited in light of the proposed EIR default curves for base case and proposed design buildings.

The part load efficiencies that are the current defaults of the DOE-2 simulation program are based upon work that was published in 1978. Given that air conditioner equipment technology has changed since that time, including the change from reciprocating to scroll compressors, the part load performance of air conditioners and heat pumps should be investigated for further upgrades to hourly cooling and heating simulation methods.

### *7.1.2 Analysis Inputs*

This section describes the buildings and efficiency measures that were studied.

#### 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 "Dollar Based Performance Standards for Building Energy Efficiency: Final Report."

## Energy Efficiency Measures

The details of the measures evaluated 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 a 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 Standard. Thermal storage was chosen because it definitely is not accurately valued in the current Standard. 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 TDV scheme, i.e. is something that may have been cost-effective in a source energy-based standard still cost effective in a TDV standard?

**Table 7: 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)]<br>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% |

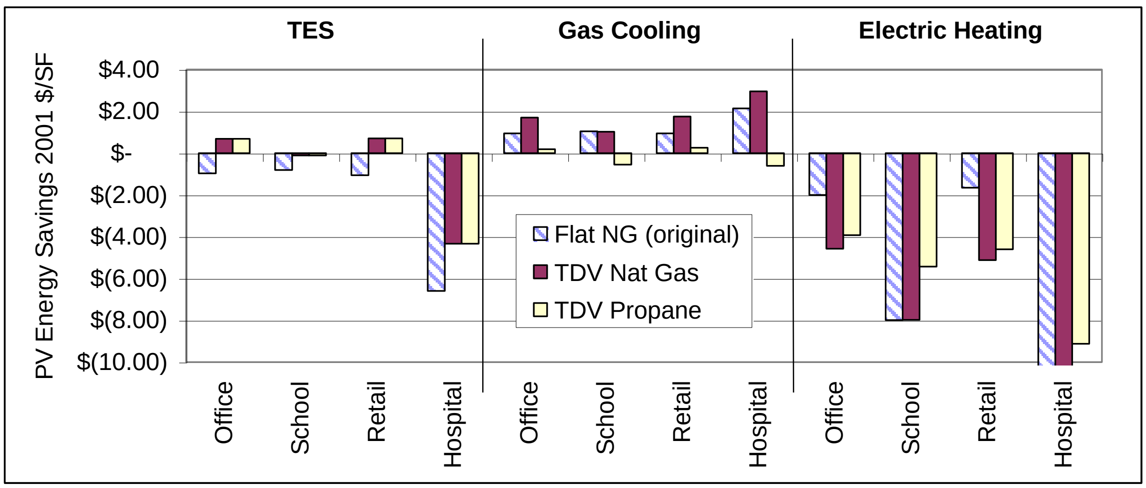
### 7.1.3 Cost Savings Results

Depending upon the building type, the cost savings results were noticeably different. Office buildings behave substantially different from other commercial building types. This illustrates 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 high efficiency envelope measures look more attractive than when evaluated with natural gas as the heating fuel. Fuel switching to electric heating had less additional annual energy costs if propane is the alternative heating fuel instead of natural gas.

The bars in Figure 1 and Figure 2 represent the energy savings of the proposed measure compared to its base case (current Title 24 requirements). The energy savings are identical for each group of three bars; the only difference is in how the energy savings are valued. In the first bar, labeled “Flat Nat Gas”, electrical energy savings are given the same value for all hours (flat valuation), and heating savings are valued at the cost of natural gas. This flat valuation is the current method used to evaluate the cost-effectiveness of California's building energy efficiency standards. In the middle bar, labeled “TDV Nat Gas”, electrical energy savings are given a time dependent valuation (TDV), and heating savings are valued at the cost of natural gas. In the third bar, labeled “TDV Propane”, the electrical savings are the same as in the middle bar, but the heating savings are valued at the higher cost of propane.

**Figure 1: TDV comparison of Daylighting, Gas Cooling and Electric Heating in Fresno Commercial Buildings**



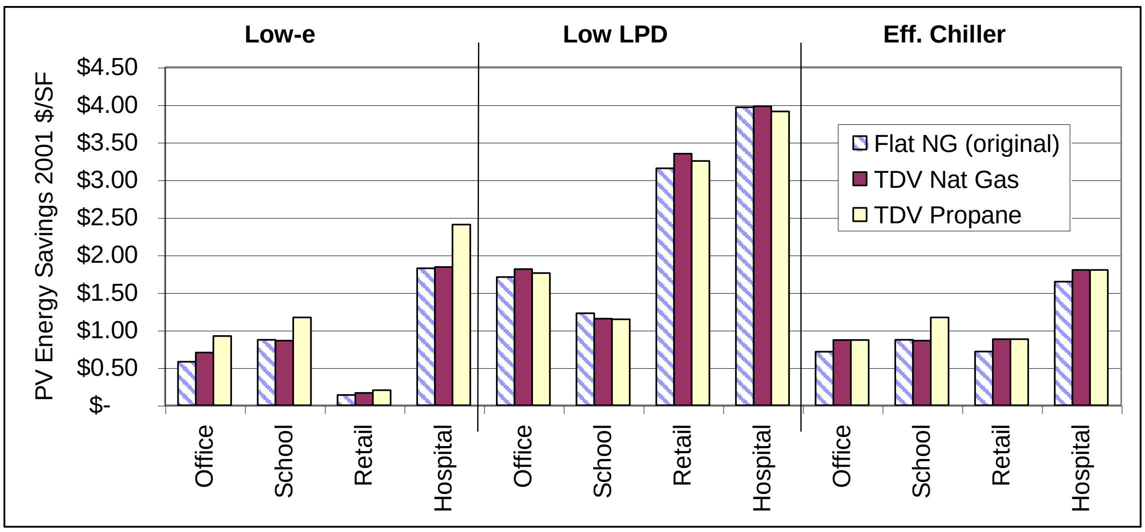

A building with a Thermal Energy Storage (TES) system consumes more electricity than a building without TES. However a well-designed system builds ice or chills brine at night when electricity is cheaper to displace cooling during the afternoon when electricity is more expensive. As shown in Figure 1, the traditional flat costing of energy gave no credit for displacing peak electricity consumption. Thus adding thermal energy storage increased flat energy costs and would have not been deemed an energy cost savings measure under the current energy efficiency standards valuation method. In comparison, under the proposed TDV costing thermal energy storage yields cost savings in office and retail occupancies. For schools, the cooling loads without thermal energy storage are small during peak periods (hot days in the summer) thus the demand savings don't outweigh the energy penalty. For hospitals, the sizing and control sequence likely need to be refined to yield TDV savings from a thermal energy storage system at this continuously operating facility.

Using natural gas to provide cooling saves more under TDV costing, the electricity displaced is more expensive during the cooling season and the natural gas is cheaper. Propane is substantially more expensive than natural gas and thus results in gas cooling being more expensive than cooling with electric chillers (negative savings) in most occupancies.

Given the addition of a "tail" to the temperature dependence of T&D costs to colder morning temperatures, electric heating costs the same or more under TDV costing as under flat costing. In comparison with more expensive (than natural gas) propane, electric resistance heating still costs more to operate, but the incremental energy costs are much less than the same comparison to natural gas fired heating. It should be noted that the energy simulation model does not factor in distribution standby losses of the heating system for the natural gas and propane heated buildings

Low-e (low-emissivity) glazing as modeled here has a lower U-factor and a lower solar heat gain coefficient (SHGC) than the base case glazing. Thus it reduces cooling loads in the summer from solar gains and reduces heat losses in the winter. As illustrated in Figure 2, TDV costing results in more cost savings being ascribed to low-e glass than flat costing. Given that low-e costs have been declining, the use of the TDV method in evaluating the code measures would emphasize the need to re-evaluate the fenestration aspects of the standards.

**Figure 2: TDV Comparison of Low-e, Low LPD and Efficient Chiller in Fresno Commercial Buildings**




Building types that have lighting schedules that match the time of use periods and temperature periods that are associated with high electricity prices (such as office and retail occupancies) have slightly greater savings from LPD (lighting power density) reductions under TDV than under flat energy costing. The other building types show the opposite effect. Reducing lighting power consumption reduces the internal gains in a building, which decreases air conditioning consumption of electricity and increases heating consumption of fuels. Thus when a building is heated with more expensive propane, the TDV savings are reduced when compared to building heated with natural gas.

Chiller loads are greatest during peak time of use periods when it is hot outside, thus it is not surprising that TDV costing methods would result in higher cost savings than using a flat energy cost. However, in most commercial buildings, cooling is required for a significant part of the year, thus the difference between time dependent and flat energy cost savings are small.

## 7.2 Nonresidential Cost Savings Study Conclusions

Several repeating patterns can be discerned from the results of this study of the effects TDV might have on nonresidential efficiency standards.

- Different building types respond differently to the efficiency measures modeled.
- Using natural gas costs to represent any fuel costs substantially undervalues the cost of propane.
- TDV 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
- Caution should be applied to relaxing standards on envelope requirements in exchange for using technologies which benefit from TDV such as thermal energy storage which depends on controls that can be more readily replaced or disabled. In other words, the persistence of time varying savings measures should be accounted for.
- Efficiency requirements for buildings should be different depending upon the heating sources used electricity, natural gas and propane, because the cost effectiveness of measures varies substantially.

# 8. RESIDENTIAL ENERGY CODE ISSUES

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. Existing calculations used 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 or equipment size. Constant efficiency calculations were acceptable given the constant valuation of energy regardless of time of day or time of year. With a time dependent valuation of energy costs, the variability of loads and efficiencies by time of day become more critical. Consistent application of the TDV method will require energy simulation improvements which must be codified in the Residential Alternative Compliance Method Approval manual.

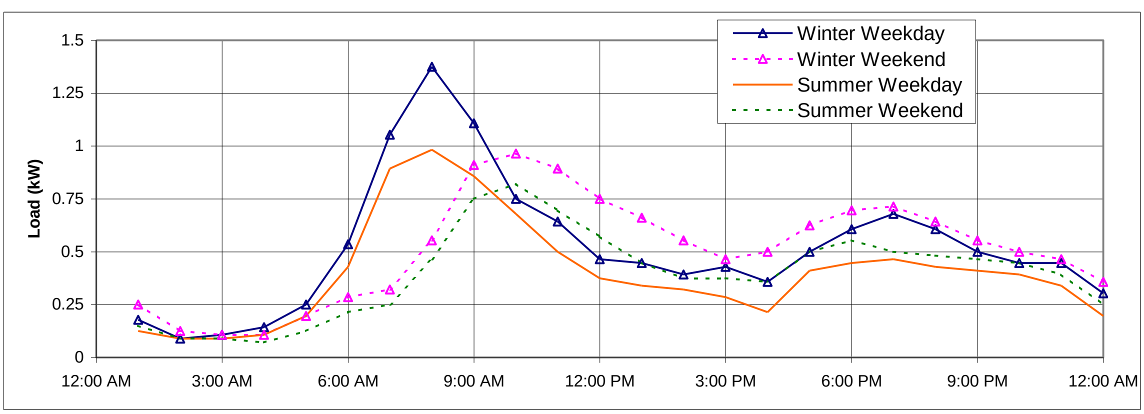
## 8.1 Modeling Enhancements

### 8.1.1 DHW Loads and Model

Historically, water heating loads were calculated on an annual basis: there was an annual water heating load and this was divided by an energy factor (similar to a seasonal heating efficiency) to yield annual domestic hot water energy consumption. Given the great variability in electricity costs based upon the time of day that it is consumed a time of day domestic hot water model is needed.

In the short term, we have made use of an average hot water heater profile that resulted from the PG&E residential appliance load study of 72 homes with electric water heaters[11]. The annual DHW load is allocated to the summer profile from May 1st to October 31st and to the winter profile from November 1st to April 30th. DHW profiles also vary depending upon whether the day is a weekday or not.

**Figure 3: Domestic Hot Water (DHW) profiles**




Further refinement of the model would have a water load profile and final energy consumption would be based also upon thermal efficiency, standing losses and entering water temperature.

### 8.1.2 Duct efficiency

Currently, the ACM has a seasonal duct efficiency factor in the energy calculations. Because duct efficiency is very dependent upon ambient climatic conditions, it is expected that time varying model would yield vastly different results when evaluated under time differentiated costing. The primary factor behind

[11] Joel Brodsky, Susan McNicoll, *Residential Appliance Load Study, 1985-1986*, Pacific Gas & Electric Regulatory Cost of Service Department, Research Section, September 1987.

duct efficiency, is attic temperature, which is in turn driven by ambient temperature and solar radiation. Thus the project team is in the process of developing a time varying duct efficiency model which adjusts duct efficiency based upon ambient drybulb temperature and global horizontal solar irradiance. The time varying duct efficiency model was not used in the following analysis.

### 8.1.3 Air Conditioning Performance

We are making use of the air conditioning performance curves that were developed for the non-residential component of this report. In a similar manner, the reference home air conditioner performance will be based upon the average of a large representative sample of air conditioners. The performance of the proposed home air conditioner will be based upon the average of the lowest 15% performing air conditioners unless actual performance characteristics are specified. Ultimately we expect that libraries of air conditioner performance will be made available to compliance program developers to simplify this process. These performance curves derate the capacity and efficiency of the air conditioner as ambient temperature increases. Given the paucity of information on part load performance, the part load efficiency curve will be based upon the current DOE-2 default curve.

### 8.1.4 Heat Pump Performance

Similar to the adjustments made to air conditioner performance with respect to ambient temperature, heat pump capacity and efficiency are effected by ambient air temperature. Thus unless equipment specific performance information is entered, the proposed design will have a default heat pump that operates at worse efficiency at peak periods than the reference home. At time of peak winter electricity prices (early in the morning) the efficiency of the heat pump may be further degraded by the use of resistance heating. Resistance heating is used when the capacity of the heat pump is unable to meet the heating load. Heating loads are greatest in the morning immediately after the setback period has ended and the setpoint of the thermostat returns to its normal daytime setting.

Our current model does not address resistance heating because the amount of resistance heating used is based upon an assumed capacity (size) of the heat pump. For the analysis contained in this report, all of the heating energy is provided by a heat pump. However, the efficiency of the heat pumps in the analysis is degraded with respect to ambient temperature. Thus this analysis would underestimate the costs of operating a heat pump.

### 8.1.5 Thermostat schedules

The current default thermostat schedule is has a fairly severe setback. This setback regime may overestimate the costs of operating a heat pump when used with a thermostat that slowly ramps the temperature up in the morning to prevent excessive use of resistance heat.

## 8.2 Analytical Cases

The CEC standard 1761 square foot prototype house was adapted for use in the analysis. 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 construction and garages.

The HVAC model for the time of use (TOU) analysis includes the varying effects of outdoor temperature and on cooling efficiency. Water heater consumption varies depends upon time of day, day of week and season.

In order to test the effect of alternate value structures for residential energy, a series of representative cases have been analyzed for presentation. Each case is consists of a single parameter change in energy efficiency measures or HVAC system in the standard prototype house.

**Table 8: Residential Energy Analysis Parametrics**

| Case Name | HVAC | Conservation Measure |
|---|---|---|
| Ceiling Ins | Fuel Furnace or Heat Pump with standard air conditioning (SEER 10) | Savings from replacing R-19 with prescriptive ceiling insulation<br>(R-30 in Oakland, R-38 in Fresno, Shasta, China Lake) |
| Low-e | Fuel Furnace or Heat Pump with standard air conditioning (SEER 10) | Savings from replacing standard clear double glass in aluminum frame (U = 0.75, SHGC = 0.7) with LOE2 glass in vinyl frame with argon fill (U=0.4, SHGC = 0.35) |
| SEER 10 to SEER12 | Savings from replacing SEER 10 with SEER12 air conditioning | Standard prescriptive compliance measures for the climate zone except higher SEER |
| Electric to Fuel DHW | Fuel Furnace or Heat Pump with standard air conditioning (SEER 10) | Savings from replacing an electric water heater (Energy Factor = 0.9) with a natural gas or propane fired water heater. |
| Heat Pump to Fuel Furnace | Savings from replacing a heat pump with a fuel furnace | Standard prescriptive compliance measures for the climate zone |

## 8.3 Comparison of Residential Results

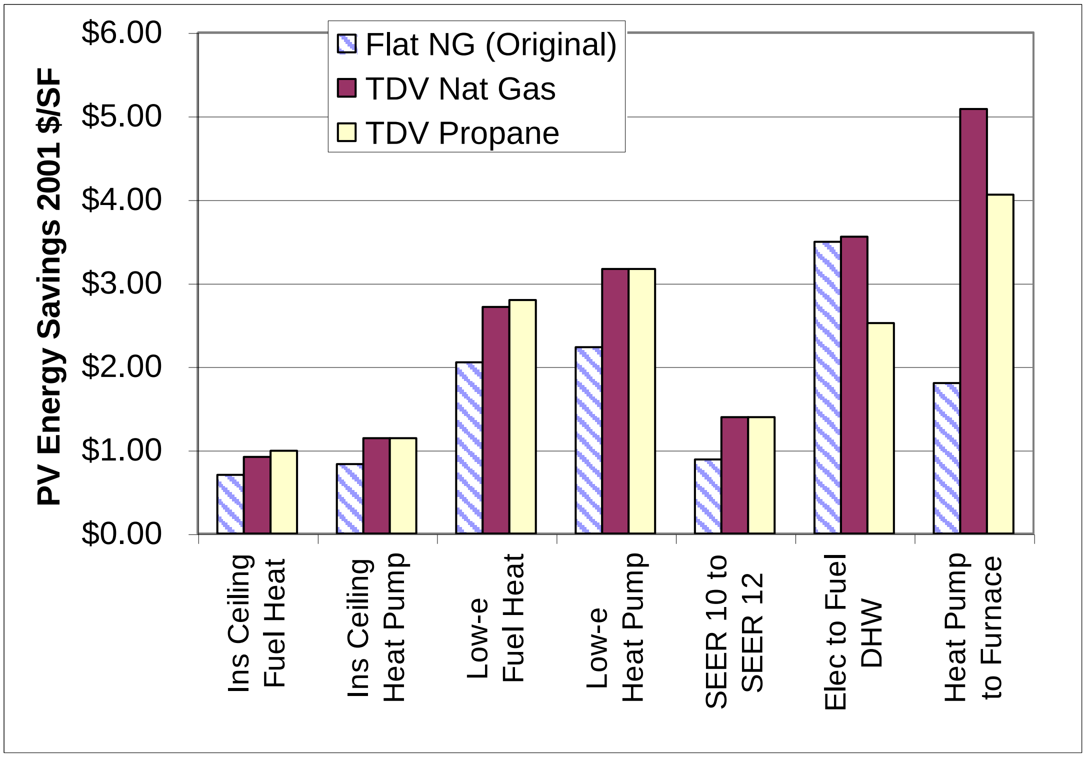
The energy savings for each case are reported in a table, which includes both the current source energy valuation and energy consumption as would be measured at the meter. The source energy calculations are done using the current compliance approach based on sensible loads and seasonal efficiencies, which do not reflect hourly modeling of temperature or part load effects. Electricity and gas consumption in this study are always modeled including these effects.

The bars in Figure 4 represent the present value (30 years at a 3% real discount rate in 2001 dollars) energy cost savings of each measure. The energy savings are identical for each group of three bars; the only difference is in how the energy savings are valued. In the first bar, labeled “Flat NG”, electrical energy savings are given the same value for all hours (flat valuation), and heating savings are valued at the cost of natural gas. This flat valuation is the current method used to evaluate the cost-effectiveness of California's building energy efficiency standards. In the middle bar, labeled “TDV Nat Gas”, electrical energy savings are given a time dependent valuation (TDV), and heating savings are valued at the cost of natural gas. In the third bar, labeled “TDV Propane”, the electrical savings are the same as in the middle bar, but the heating savings are valued at the higher cost of propane.

Fresno is a Central Valley climate with significant heating and cooling loads. Virtually all new homes are air conditioned and air conditioning is a daily fact of life for most residents in summer months. Under the TDV valuation, measures that reduce air conditioning load are preferentially weighted by the higher cost of electricity when ambient temperatures are high.

Time dependent valuation of the energy savings from ceiling insulation is approximately 30% higher than a flat valuation. Ceiling insulation reduces cooling loads the most during hot times of year when electricity prices are highest and reduces heating loads the most during cold times of year when electricity and fuel prices are also relatively high. Propane is about 50% more expensive than gas, thus all measures that decrease fuel consumption save more money when propane is the fuel rather than natural gas. However, when ceiling insulation is evaluated with propane as the heating fuel, this increases the cost savings of more ceiling insulation by only 10% because 80% of the cost savings are due to reduced electricity consumption. When ceiling insulation is evaluated for a building heated by a heat pump, the TDV savings are greater than the savings in a home heated with natural gas or propane. All of this indicates that homes heated by propane could cost-effectively be required to have more ceiling insulation than natural gas heated homes and heat pump heated homes could have even more ceiling insulation still.

**Figure 4: Residential Measure Evaluation for Standard Home (1,761 SF) in Fresno**




The upgrade from clear glass to low-e glass, saves as much heating energy as increasing ceiling insulation from R-19 to R-38 but cooling savings are tripled. The lower U-factor of low-e glass reduces both heating and cooling loads and the lower SHGC reduces solar gains which is beneficial in the summer and slightly negative in the winter. Since the savings are greatest when the climatic conditions are at their extremes the TDV savings figures are higher than the traditional flat valuation of cost-savings.

Replacing a heat pump with a fossil-fueled furnace is a positive compliance trade off under all scenarios including the scenario where propane is the fuel used. This result is due to the synthetic "tail" that was developed for electric marginal T&D costs so that high costs would be allocated to the coldest hours of the year. The purpose of these high electricity costs is predictive and preventative. Currently T&D costs are low in the winter partly because historically electric heating has been restricted by energy codes. If electricity were to be evaluated at the low existing winter T&D costs, this could result in increased electric heating which in turn would cause T&D costs in the winter to rise and create a long term oscillation between electric heating costs and electric heating code restrictions. This scenario indicates that winter electric costs under TDV will provide even more of a cost signal to discourage electric heating than the current costing for evaluating the cost-effectiveness of code measures.

Increasing the seasonal energy efficiency ratio (SEER) rating of air conditioning from the minimally compliant value of 10 to 12 yields almost twice as much cost savings under the TDV method. This is not surprising since air conditioners consume more electricity during times of higher electricity prices. This result should be tempered by findings that the efficiency of many SEER 12 air conditioners drops off more quickly during high temperature conditions than the efficiency of SEER 10 air conditioners. If this finding is borne out, the revised hourly consumption can be multiplied by the hourly TDV energy costs to develop new TDV cost savings figures.

# 9. CONCLUSIONS

Since being first established in 1977, the building energy standards (along with standards for energy efficiency in appliances) have helped Californians save more than $11.3 billion in electricity and natural gas costs[12]. Every three years, these standards are updated to keep pace with technological advances and market conditions for energy savings technology.

Currently, the development of the standards and the alternative compliance software have been based upon flat energy costs - energy is valued the same regardless of time of day or year that it is consumed. However, the societal costs of energy do vary depending upon when it is consumed. Consumers pay more for energy during peak demand periods[13]; also less efficient and more polluting generation plants operate during periods of high demand.

Future development of California's building energy and appliance standards should incorporate time dependent valuation (TDV) of energy costs when determining the cost-effectiveness of measures and in application of the performance (computer simulation) method. This would help shift the emphasis in the building standards to those measures that reduce peak loads on the electricity and natural gas supply and delivery systems. This, in turn, would help better utilize the energy delivery systems, reduce system demand, and result in lower long-term utility costs for California consumers.

Work is currently under way to refine the tentative TDV methodology reported in this document. The refined methodology, based on the latest available energy cost data and analysis, will be available for public review and scrutiny beginning in the fourth quarter of 2000.

Under a time dependent valuation of energy for developing energy standards, better knowledge would be needed on energy efficiency measures. In the past with flat energy costing, the only question was how much energy does a given measure save. In the future with time dependent energy costing, when energy is saved will be as important as how much energy is saved.

Cost-effectiveness evaluation of measures results from applying hourly energy costs to hourly models of building energy consumption. Thus building energy models must be able to predict energy performance on an hourly basis and not just on a seasonal basis. Currently, the residential alternative compliance model (ACM) software applies a constant seasonal efficiency (SEER) to space cooling loads. However, the efficiency of residential air conditioners varies with respect to outdoor temperature and how much cooling is required. At peak cooling conditions, when electricity costs are highest, the SEER (seasonal energy efficiency ratio) is not a good predictor of energy consumption. This indicates that a better residential cooling model is needed and that the efficiency metric of interest for code compliance is not the SEER but perhaps an energy efficiency ratio (EER) at peak load conditions.

The commercial alternative compliance model (ACM) software applies a variable cooling efficiency that is a function of outdoor temperature and cooling loads. When the cooling equipment is a chiller, the manufacturer provides test data that characterizes the chiller performance under a wide range of conditions. However, for unitary "packaged" equipment, only the SEER is required by the energy standards and part load performance data is rarely provided. Currently, the performance curve used is over 20 years old and does not provide credit for newer unitary compressor technologies such as variable speed compressors, scroll compressors, thermal expansion valves (TXV), etc. A series of new default curves should be developed to account for the enhanced peak day performance of some of these technologies.

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[12] CEC web page "Title 24, Section 6 California's Energy Efficiency Standards for Residential and Nonresidential Buildings," http://www.energy.ca.gov/title24/98_standards/index.html

[13] Even those consumers on flat rates pay more for energy consumed on peak because the cost of service for peaky loads is higher and this eventually is passed back to the customers in terms of higher flat rates.

To be adopted, the use of TDV for developing building standards must be evaluated and accepted by stakeholders in the energy standards arena. To provide maximum flexibility to these stakeholders, we are developing research versions of the residential and nonresidential alternative compliance model (ACM) software to be used with a spreadsheet that applies the hourly costs of energy to the hourly energy consumption values generated by these models. This will provide a transparent analysis tool showing how TDV costs are applied, making it easy for stakeholders to observe the mechanisms that affect the outcomes of measure comparisons.

Public meetings will be held to gather comments so that this TDV method can be considered for use in evaluating measures for the 2005 Standards and for use in the 2005 ACM software.

# 10. APPENDIX - DETAILED DISCUSSION OF ECONOMIC FACTORS

## 10.1 Electricity Costing Factors

The societal electricity costs used to evaluate the TDV cost effectiveness of energy efficiency measures for inclusion in the building efficiency standards are a combination of:

- **Commodity costs** - the cost of electrical generation as delivered to the California Power Exchange (PX). These costs are modeled as a time series based upon historical prices on the power exchange with an adder to account for the costs of bringing new generators into the PX. (Note that these costs are modeled as time series and are not directly correlated to temperature the way transmission and distribution costs are - the prices on the power market are affected by more influences than just regional loads.)
- **Transmission and Distribution marginal costs** - this is the cost of additional transmission and distribution capacity to handle peak loads. These peak loads are correlated to high temperatures and the costs are allocated from the total costs to hourly costs by peak capacity allocation factors (described in more detail later in Section 10.1.2). Given the timing and load factor of the residential versus non-residential loads, and the costs associated with equipment serving residential versus non-residential loads, these costs are different for the two building types.
- **Fixed costs** - these include all the other costs reflected in customers' utility bills, such as taxes, billing and meter reading, interest on capital, company profit and return to investors. These fixed costs are the difference between the total revenues collected by the electric utilities and the totals of the commodity, transmission and distribution marginal costs. These fixed costs are applied as a flat adder i.e. the fixed costs are the same $/kWh regardless of time of day, day of week or season of year. Note that this value is different for residential and non-residential buildings and differs by region so that costs are scaled up to a statewide average of revenues.
- **Environmental externalities** - these costs are additional societal costs not currently extracted by environmental protection or other regulatory programs (which are already reflected in the fixed cost component). The externalities estimation is a "least cost" valuation of externalities based upon emission trading credits. The analysis here assumes that all marginal generation is gas fired, either a natural gas combustion turbine or a combined cycle turbine and that the main emissions of economic value are NOx and $CO_2$.
- **1992 Adder** - This adder brings the overall cost of TDV electricity up to the same total value of electricity costs used to develop the cost-effectiveness of the 1992 standards. This serves to keep the overall stringency of any proposed changes to the Title 24 Standards comparable in stringency to the 1992 Standards.

### *10.1.1 Commodity Costs (Generation Market Price)*

For the TDV project, we have assumed that the Generation market price forecast be based on the CEC's projections and methodology. The CEC continues to run production simulation models (MultiSYM) and publish those results on its Web site (http://www.energy.ca.gov/reports/2000-03-13_300-00-001.html). For long-range projections, the CEC staff recommends the use of the all-in cost of a new entrant to set the future market prices using the following multi-step process

1. All-in cost for new entrant calculated for each year, given technological innovation assumptions, and the long-range gas price forecast.

2. All-in cost converted to monthly average prices using month factors prepared by Richard Grix[14].
3. Hourly "typical week" market prices are adjusted to match the monthly averages. The typical week market prices are from staff Multisym analyses and can be found at http://www.energy.ca.gov/energyoutlook/documents/300-00-001_data_files/

## Ancillary Service Costs

Generation energy costs borne by consumers would consist of both the costs from an energy market such as the Power Exchange ($PX_h$) and the ISO Ancillary service market ($ISO_h$). Without any dependable forecasts of ancillary service costs, one is left with two choices: 1) add ancillary service costs as a simple percentage addition to the $PX_h$ costs; or 2) create an hourly ancillary market price profile modeled after the actual ancillary costs observed in the market.

If market-based ancillary service costs are desired, the hour-ahead ancillary service market prices could be based on NP15 for both market-procured and self-provided quantities[15]. The hour-ahead prices are chosen because ancillary services are used to support system operation in real time. But if the hour-ahead market is inactive, the day-ahead market prices should be used. The total ancillary service costs for any hour should be divided by the total kW demand at that hour to convert the ancillary service costs into average $/kWh values.

Once initial ancillary service costs are established (either as a simple percentage, or as an hourly profile), the task still remains of forecasting the ancillary cost levels into the future. Review of data from December 1998 to November 1999 reveals that 63-89% of the total ancillary service cost is associated with regulation and frequency support. (CEC 2000 report, Appendix D, p. D-7). Depending upon how the TDV team anticipates these costs will change in the future, they can be held constant in nominal terms, held constant in real terms, or escalated in proportion to the $PX_h$ price.

A simpler assumption is to derive ancillary service costs as a multiple of the market prices. The CEC staff recommends a value of 5%. While this is lower than the 13% observed during the first year of the open market operation in California, it would appear to be a reasonable long-run estimate. The generation market price forecasts developed for the TDV project uses this 5% assumption.

## All-in Costs

All-in costs include return on capital investments, so assumptions of the cost structure and equity return requirements of a new generation entrant into the market can significantly impact the all-in cost estimates. In addition, assumptions on new plant construction costs, heat rates, and gas prices will impact the estimates. In general, however, agreement can typically be reached on the assumptions for the near term, based on published information, such as the Gas Turbine World Handbook.

The CCGT's per MWh all-in cost in year "t" is computed as follows:

$$All\ in\ Cost = \left\{ \frac{\left[ CC \times (1 - T1) + Fixed \right]}{\left[ (8760 \times CF \times 1000) + \left( \frac{Gas \times HR}{1000} \right) + VOM \right] \times [1 + AS\%]} \right\}$$

Where

CC is the capital cost of the CCGT ($/kW) in year "0"

FCR is the fixed charge rate used to annualize the cost of the CCGT

[14] Richard Grix, Electricity Analysis Office, Energy Information and Analysis Division, California Energy Commission

[15] NP15 is "North of Path 15" -the transmission bottleneck between Northern and Southern California

TI is the annual rate of technological improvement

Fixed is the annual fixed cost of the CCGT ($/kW)

CF is the annual capacity factor of the CCGT

Gas is the $/MMBTU delivered gas price

HR is heat rate (BTU/kWh)

VOM is the variable operating and maintenance cost ($/MWh)

AS% is the ancillary cost adder (%)

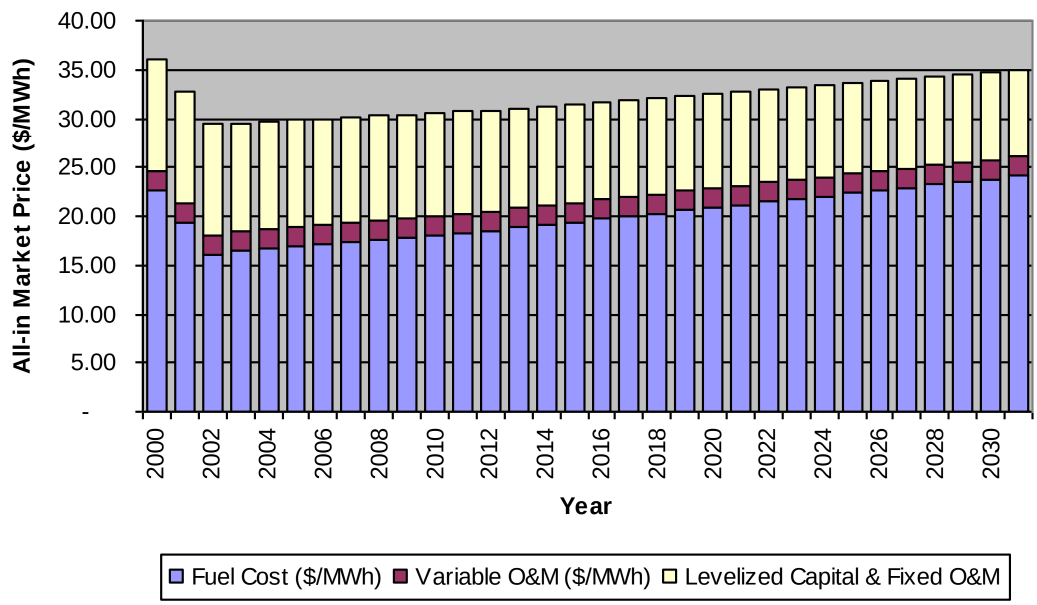
**Table 9: New Generation Assumptions**[16]

| | | |
|---|---|---|
| **Generation new Entrant Costs** | | |
| **Cost Structure** | | |
| Percentage Debt | 60% | Grix to PG&E, "Cost to Build and Operate a New Plant" |
| Debt Cost | 8.50% | Grix to PG&E, "Cost to Build and Operate a New Plant" |
| Equity Return (after tax) | 12% | Grix to PG&E, "Cost to Build and Operate a New Plant" |
| Marginal Tax Rate | 40% | Grix to PG&E, "Cost to Build and Operate a New Plant" |
| WACC (after tax) | 7.86% | |
| Fixed Charge Rate | 11.85% | D. Vidaver, 5/24/00 E-mail |
| | | |
| **Construction Cost ($/kW)** | 550 | Grix to PG&E, "Cost to Build and Operate a New Plant" |
| Capital Fixed Cost ($/kW-yr) | 65.175 | |
| Non Capital fixed Cost ($/kW-yr) | 10 | Grix to PG&E, "Cost to Build and Operate a New Plant" |
| Total Fixed Cost ($/kW-yr) | 75.175 | |
| Assumed Cap Factor | 75% | |
| Converted Fixed Cost ($/MWh) | 11.44 | |
| Annual Technological Improvement | 1% | CEC Electricity Analysis Office |
| **Ancillary Service Costs** | 5% | CEC Electricity Analysis Office |
| **Variable Costs** | | |
| Heat Rate | 6800 | (Table III-1) |
| Variable O&M ($/MWh) | 2 | (Table III-1) |

[16] The bulk of these assumptions are based on Grix, R. (2000) *Cost to Build and Operate a New Plant*, Memo to PG&E, CEC (CA: Sacramento). Assumptions on fixed charge rate, ancillary services adder, and technological improvement are based on E3's communications with the CEC Electricity Analysis Office.

The projection of the market price for electricity commodity is shown in Figure 5. Note the estimates here forecast a dramatic decline in natural gas prices until 2002 and then a gradual rise in prices thereafter.

**Figure 5: Market Price Forecast**




## Projection of Price Shapes

The CEC currently updates its market price forecasts on at least an annual basis, and has recommended to the State Legislature that it continue to do so in the future.[17] As part of the forecast development, the CEC's models calculate hourly market prices for typical weeks for each of the twelve months. The hourly prices could be derived by mapping the typical week to the 28 to 31 days in each month, and scaling all of the monthly prices up to match the forecasted market price for that month. The monthly market price is developed by applying fixed monthly price ratios to the annual all-in cost of the new CCGT. The monthly price ratios are shown in Table 10.

[17] Keese, W.J., et al, (2000) *Forecasting & Data Collection Responsibilities*, SB110 Report to the Legislature, California Energy Commission (CA: Sacramento)

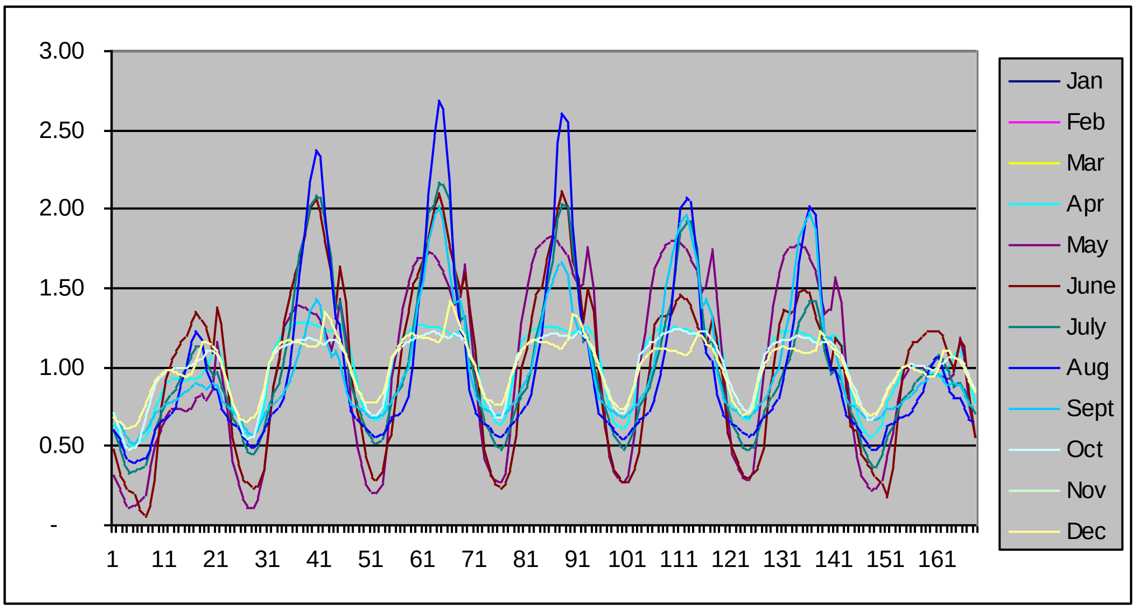
**Table 10: Monthly Price Ratios of the All-In Cost of a New Combined Cycle Generation Turbine**

| Month | Price Ratio | Month | Price Ratio |
|---|---|---|---|
| Jan | 0.979 | Jul | 0.961 |
| Feb | 0.895 | Aug | 1.569 |
| Mar | 0.777 | Sep | 1.642 |
| Apr | 0.670 | Oct | 1.094 |
| May | 0.618 | Nov | 1.068 |
| Jun | 0.625 | Dec | 1.092 |

The hourly price for any month, m, and for any hour of the day, h, is given by the following:

$$Price[m,h] = All\ in\ Cost \times Monthly\ Price\ Ratio[m] \times Typical\ Shape[m,h]$$

**Figure 6: Monthly Typical Week Market Price Profiles Normalized to Average 1.0.**




The hourly market price forecast can be found in Gen Price Forecast2.xls [Hourly Forecast]

### *10.1.2 Transmission and Distribution Costs*

In 1999 the TDV team identified the use of temperature as a possible proxy for determining how much electrical demand in any hour would contribute to the UDC's need to expand wires capacity in an area. The study in 1999 examined six areas in a proof of concept exercise. This year 2000 work presents a much more comprehensive examination into the adequacy of temperature as a proxy for peak demand loading on the T&D system.

**Summer Peak:** Peak period is all weekday hours with temperatures within 15 degrees of the highest observed temperature in the area (weekday only). This 15 degree span defines the hours that could drive peak demand, and thus drive the need for capacity expansion. This definition is independent of climate zone.

The hours with the highest temperatures will likely have the highest demand, and also the highest likelihood of driving the need for capacity expansion. Therefore, the higher the temperature, the larger the weight assigned to that hour. The weights are referred to as Peak Capacity Allocation Factors, or PCAFs. The PCAFs are divided into the 15 categories corresponding to each degree in the peak period. The highest temperature (rounded to full degrees) receives a value of 13.33%. This means that 13.33% of the T&D capacity cost for the area is assigned to weekday hours with that corresponding temperature (when rounded to the nearest degree). The PCAF percentage declines linearly for the other temperature categories until the 15$^{th}$ highest temperature category receives zero PCAF.

The T&D cost assigned to any hour of the year is:

$$T\ \&\ D_{cost}[h] = \frac{PCAF\left(Temp[h]\right)}{NumHours\left(Temp[h]\right) \times T\ \&\ D_{cap}Cost}$$

Where

Temp[h] is the temperature category for that hour. (the nearest whole degree temperature)

PCAF[Temp[h]] is the total percentage of capacity cost allocated to that temperature category

NumHours is the number of hours that fall into that temperature category over the year

T&DcapCost is the T&D marginal capacity cost in $/kW-yr

Note that if there are temperature categories with no hours, the PCAF for that category should be allocated to the next highest temperature category that has hours.

**Winter Peak:** Peak period and calculations are analogous to the summer case, but in reverse. The highest PCAF is assigned to the lowest temperature category, and the PCAFs decline as the temperature increases. The summer analysis was limited to weekdays. The winter analysis is limited to weekdays between 7am and 9pm. Like the summer analysis, the winter peak period is defined as a 15 degree temperature span.

**Policy Issue:** Most areas within California are summer peaking. The CEC has made a purposeful effort to discourage electric resistance heating in the past, and has indicated that this remains a goal for the new standards. One way to promote this goal is to include a winter PCAF curve for all areas, even those that are currently summer peaking. The winter PCAF curve would reflect the costs that would be imposed on utilities if the areas were to become winter peaking areas. Because we have developed a PCAF method that only requires information on temperature (not actual loads), the winter PCAF weights would be valid regardless of the current area's peaking characteristics.

The issue is whether the T&D marginal capacity costs should be split between the summer and winter or replicated for the summer and winter. For example, if the T&D capacity cost is $50/kW-yr. Should the capacity cost be split $25 and $25 between summer and winter, or should $50/kW-yr be assigned to the summer and another $50/kW-yr be assigned to the winter? The TDV project team recommends the second approach because it does not dilute the summer pricing signal. The problem is that duplicating the winter value would overly reward measures that reduce both summer and winter demands (such as shell measures).

**Question:** Is there some way to have the simulation models impose the winter costs only when electric usage is increased or similarly be able to impose the higher costs as a penalty, but not a reward in areas that are currently summer peaking?

The remainder of this section details the analysis undertaken to arrive at the above recommendations

### PCAF Calculations

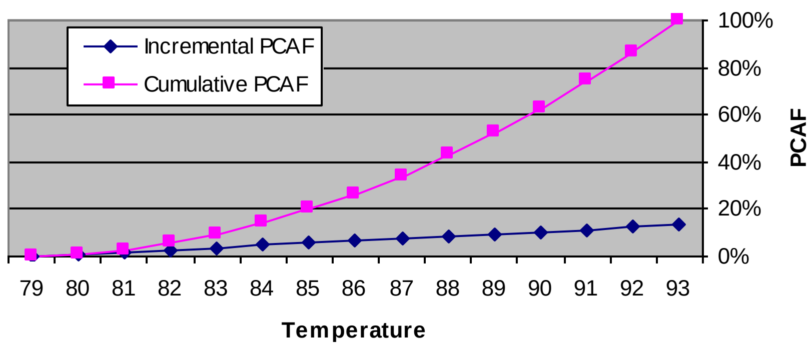
The Peak Capacity Allocation Factors were calculated from the simulated hourly shapes provided by PG&E's rate department[18]. The simulated shapes are from PG&E's AREALOAD model which PG&E has employed and defended in the regulatory arena in various forms since 1992. Actual measured data for 1999 is available for some substations and circuits through PG&E's SCADA system. We chose to use the simulated data set to assure full representation of the loads within a DPA (often SCADA does not cover an entire area) and to assure representation of all the DPAs (SCADA is not fully deployed across PG&E's entire service territory.)

### PCAF Correlations

Examination of the 31 sample areas revealed that for summer peaking areas, the peak period occurred during hours with temperatures within 15 degrees of the annual maximum. For example in a moderate area like Mountain View, the peak temperature in 1999 was 93 degrees. In an area like this, temperatures in the high eighties would be of concern to the planners. Conversely, in Concord where the temperature topped out at 106 degrees, the main concern to planners would be usage when the temperature rises into the mid to high nineties.

Having determined the duration of the peak period, the next task was to develop a functional form based on temperature that would reasonably match the actual PCAFs. For simplicity, we settled on a simple functional form that increased linearly with temperature. Because the total PCAFs must total to 1.0, the linear function form, with zero weight at the 15$^{th}$ highest hour, and maximum weight at the highest temperature hour resulted in the following PCAF shape.

**Figure 7: Incremenal and Cumulative Peak Capacity Allocation Factors (PCAF)**




To determine how well this functional form predicts the PCAF values, the cumulative PCAF functional form is plotted against the actual cumulative PCAFs. In general the functional form of the PCAF's matched well the actual PCAFs. Some areas had a wider range of temperatures and this may well result from time dependent effects or perhaps storage of heat in thermal mass of buildings.

### Winter Peaking Areas

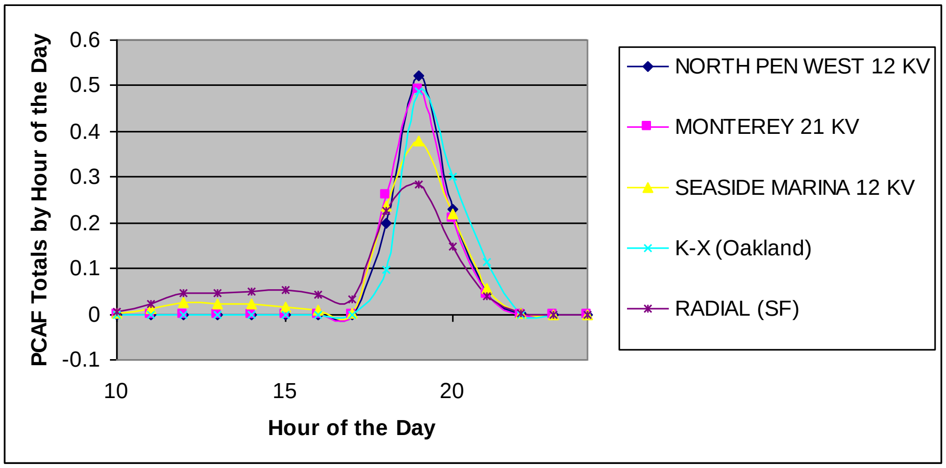
The winter peaking areas display roughly the same 15 degree peak relationship as we saw for the summer peaking areas. The predicted shapes, however, are noticeably offset to the left of the actual PCAFs. This occurs because the minimum temperature in an area rarely occurs at the same time as the highest demand in an area. Unlike the summer peak, when the maximum temperature occurs during or near business hours, the winter minimum temperature occurs around dawn. Since there is little activity or heating occurring at dawn, using this minimum temperature as a proxy for peak demands is inappropriate.

[18] Please refer to the 1999 report for a detailed discussion of the PCAF methodology.

A review of the temperature profiles for Moffett Field (North Pen West), Monterey, and San Francisco indicate that the temperature at 7pm is a better proxy for the minimum temperature to use for PCAFs This would shift the predicted shapes eight to ten degrees downwards --- lining up the predicted results very closely with the actual PCAFs.

As shown in Figure 8, the PCAF distribution by hour of the day also indicates that for these areas, the PCAFs never occur past 9pm. This suggests that the PCAF prediction formula should only consider hours of the day between 7am and 9pm. Further study is probably warranted to determine the timing of peaks in areas that do not have access to natural gas and may experience morning hot water heater driven peaks. But the currently identified relationship is adequate for the present.

**Figure 8: Distribution of PCAF's by Time of Day**




## *10.1.3 Fixed Costs*

The above costing is marginal - it only considers the incremental cost of additional loads. But additional energy consumption typically results in additional fixed charges in addition to the marginal costs. These fixed utility costs include all of the other costs that are reflected in customers' utility bills, such as taxes, interest on capital, and billing and meter reading costs. In our model, these are calculated as a flat adder ($/kWh) across all hours such that the consumption pattern of the average residential and commercial customer has the forecasted average rate for each class. An advantage of this approach is that equitable comparisons can be made across utilities, which use different accounting methods for calculating marginal costs. In addition, over the long term, some of the items traditional considered fixed costs can be attributed to long term load growth. Table 1 in section **Error! Reference source not found.** contains a summary of the components of electricity costs including fixed costs in 2001 present valued dollars.

## *10.1.4 Electricity Environmental Externalities (Air Emissions Value)*

Not all of the costs borne by society for fuel extraction, generation, delivery and consumption of electricity are captured in the revenues collected. There are additional societal costs beyond the costs paid by the consumer. These externalities not factored into the nominal costs of electricity include: elevated health risks, increased forest and crop losses, accelerated surface deterioration or soiling from air emissions, lower real estate prices near transmission lines and power plants, etc. Though externalities are often treated as being synonymous with environmental pollution, they can also be linked with aesthetic issues and related to actual and perceived value. The calculation of a value for externalities should not be seen as a negative exercise; the societal acceptance of electricity indicates that the overall benefits received from electricity are greater than the sum of the levied costs of electricity and the "hidden costs" represented as externalities.

The benefits of electricity are not accounted as "negative costs" in this setting because the total societal savings (including externalities) from reduced electricity consumption are used to calculate the acceptable additional societal costs of efficiency measures that provide the same value to the end-user while using less electricity.

Environmental externalities are valued in a time-dependent format because more fuel is consumed and more emissions are generated per kWh of electricity during periods of highest commodity costs. During periods of highest commodity costs, it becomes economic to operate less efficient power plants. Less efficient plants (with a higher heat rate) consume more fuel and produce more emissions per kWh of electrical energy.

There is a tremendous range to the estimates of the cost of environmental externalities - the range of figures reflects disagreements on what items are externalities, including, for example, the various statistical models of the impact of pollution on health as well as the valuation of health.

The options for evaluating environmental externalities are based on a] market costs as experienced in emissions trading, and b] emissions abatement costs. For a detailed discussion on emission costs, please see their associated paper *Valuation of Environmental Externalities from Electricity Generation*. This technical discussion focuses on the mathematical derivation of the cost estimates.

Under the most recent Warren Alquist Act revisions, the CEC is still required to "include a value for any costs and benefits to the environment" in estimating the cost-effectiveness of energy resources and programs. However, there has not been an official CEC proceeding or decision on the topic of valuing environmental externalities and adders since the Electricity Report of 1994 (ER94). While senior CEC staff concur that there is still a need to consider environmental costs and benefits (consistent with the Warren Alquist Act), there is little confidence in the externality values that were calculated for ER94 or other documents. One senior staff member indicated that the present staff attitude is to "not endorse the use of any externality number for any purpose."

Among CEC staff, there is general skepticism regarding the estimation of externality values on the basis of environmental damage functions. Although using environmental damage functions best represents the theoretically correct economics, it is seen as having less practical value than simpler approaches based on mitigation costs, emission allowance market prices, etc.

This rather significant distancing from the idea of quantifying the value of environmental externalities is further complicated by the inclusion of such valuations, however simplistically, in PG&E's PY2000 Annual Earnings Assessment Proceeding filing. The economic valuation input assumptions shown in Table TA 1.1 of Volume III of this filing were approved by the CBEE and show $/MWh values through the year 2023, including environmental externality values.

Meanwhile, other states have enacted legislation or regulations calling for the consideration of environmental externalities in electricity planning, and several (Massachusetts, Minnesota, Nevada, New York, Oregon) have assigned values to certain categories of emissions. The values are generally in the same order of magnitude as those for California (see Table 1 below). These externality values are generally based on marginal control costs, and they are used for indicative purposes only. Massachusetts began to require the direct application of externality values in electricity resources decisions, but this measure was successfully challenged and finally overturned by the Massachusetts Supreme Court.

Thus, there are continuing academic debates, political controversies and legal complications surrounding the issue of environmental externality valuation, as well as a severe lack of convincing empirical data to resolve the issue. It is clear that a simple, practical approach is needed, at least in the interim until greater scientific and political consensus is reached to resolve some of these controversies and uncertainties. To flesh out the positions of various stakeholders in the environmental externalities debate, we reviewed a wide range of expert opinions on how to evaluate the externalities associated with energy consumption.

Based on these sources, we have arrived at the following cost estimates:

**Table 11: Emission Cost Scenarios**

| Cost $/ton | NOx | SO2 | VOC | PM-10 | CO2 |
|---|---|---|---|---|---|
| CEC ER94 | 9120 | 4490 | 4240 | 4610 | 9 |
| CEC 1998 internal estimate | 1800 | 1780 | 530 | 910 | 9 |
| Other States Min | 850 | 150 | 1010 | 330 | 1 |
| Other States Max | 7500 | 1700 | 5900 | 4600 | 24 |
| TDV Recommendation | 3000 | 0 | 0 | 0 | 9 |

"Other States" refers to values used in Massachusetts, Minnesota, Nevada, New York, and Oregon.

These estimates are based on two related methods to estimate environmental adders that have been designed to capture the external benefits of energy-efficiency measures and programs. These two approaches focus on a) marginal emission reduction costs (MERC) and b) emission trading market-clearing prices.

These methods share a common assumption, being that the current level of legislated/ regulated emission compliance is based on a societal consensus, which equates to an assumed efficient (and acceptable) degree of emission reduction. Although regulated emission levels are political decisions having little linkage to economically optimized reductions, these criteria are easily observable once emission controls or trading markets are in place.

These two methods are also related, at least in theory, by the fact that MERC drives both the supply and demand aspects of emission reduction offsets and credits in the market. Theoretically, at a given price threshold for emission credits, a firm should ideally implement emission reductions that cost less than the credit price, while concurrently buying offsets or credits for any remaining emissions. Conversely, a firm that can reduce emissions at a cost less than the threshold price should do so in order to profit by selling its excess emission credits.

At each price threshold for emission credits, the sum of all the incremental emission "demand," (i.e., firms that have excess emissions that cannot be reduced further at the given price), and the incremental emission credit "supply," (i.e., firms that can generate excess credits from additional reductions), define the demand and supply curves for emission offsets and credits. In theory, the intersection of these curves defines the price at which credits should be exchanged under market equilibrium. Of course, this scenario ignores many real-world limitations, such as transaction costs, imperfect market information, barriers to entry and exit, market power and strategic behavior. But at least conceptually, the observed market trading prices for emission credits should reflect to some degree the marginal costs of emission reductions for participants in that market.

### Scope of Analysis

Although California has the most diverse set of generating sources in the country, it is anticipated that the marginal generation source in any future California-based scenario will be gas-fired thermal plant. While much of the state's electricity supply comes from hydro and nuclear sources, it is unlikely that an increase or change in energy-efficiency activities would influence the amount of energy generated from these sources. Because these sources have relatively low variable costs, they are essentially "must run" resources that are baseloaded as much as allowed by technical limits, rather than being dispatched (like a thermal plant) on an economic basis. For this reason, the externality analysis is limited to thermal plants. The further assumption is made that the marginal fuel will be natural gas (rather than diesel, coal or fuel oil). Lastly, the externality analysis is limited to air emissions, because for thermal plants, the most significant environmental impacts and externalities are associated with air pollution emissions.

The pollutant species that have most impact in terms of valuing externalities in California are Nitrogen Oxides (NOx) and Carbon Dioxide ($CO_2$). One should monitor changes in the regulatory or market action regarding particulate matter less than 10 microns and 2.5 microns (PM-10 and PM-2.5) as well as out-of-state Sulfur Dioxide ($SO_2$) sources. This analysis does not expect Volatile Organic Compounds (VOCs), Reactive Organic Gases (ROGs), Carbon Monoxide (CO) or other species to be significant in terms of relative emissions.

### Generic Plant Emission Costs

This section provides an indication of how a range of emission costs ($/ton) would translate to energy adders ($/MWh). Emission factors from a typical gas-fired steam turbine generator can be used to estimate the contribution of each pollutant to an overall externality value based on the values listed above for individual pollutants. Table 12 shows the emission characteristics for generic natural-gas fired plants such as combustion turbines (CT), combustion turbines with selective catalytic reduction (CT with SCR), steam turbines, steam turbines with selective catalytic reduction (ST with SCR), combined-cycle gas turbine (CCGT), and combined-cycle gas turbine with selective catalytic reduction (CCGT with SCR).

**Table 12: Emission Rates from Generic Sample Plants**

| Emission Rates | NOx Emissions (lb/MWh) | SO2 Emissions (lb/MWh) | VOC Emissions (lb/MWh) | PM-10 Emissions (lb/MWh) | CO2 Emissions (ton/MWh) |
|---|---|---|---|---|---|
| Generic CT | 2.80 | 0.20 | 0.20 | 0.20 | 0.80 |
| CT with SCR | 0.40 | 0.20 | 0.20 | 0.20 | 0.80 |
| Steam Turbine | 1.70 | 0.01 | 0.01 | 0.03 | 0.60 |
| ST with SCR | 0.25 | 0.01 | 0.01 | 0.03 | 0.60 |
| CCGT | 1.00 | 0.01 | 0.07 | 0.10 | 0.40 |
| CCGT with SCR | 0.15 | 0.01 | 0.07 | 0.10 | 0.40 |

The change in emission costs due to building energy usage changes depends upon the plant “on the margin.” The basic idea is that only the last plant in the dispatch order would be affected by the change in usage. A simple estimation therefore involves determining the type of plant on the margin for each hour, and assigning the emission cost of that plant to that hour. Lacking better information, we estimate the plant on the margin based on the variable operating costs of the generic plants listed above (using the plants without SCR)[19]. The plant on the margin at any hour is the plant that has the highest variable operating cost that is less than the generation market price for that hour. This estimation method places the “dirtiest” least efficient units on the margin when the market price is highest, and the cleanest units on the margin when the market price is lowest.

The operating characteristics of the generic plants are shown below.

[19] The CA ISO does not track the plant-type of the last dispatched plant. Efforts to attain similar information for market price simulation models were also unsuccessful. As a result, the market price forecast was used as a proxy for the plant-types. The analysis assumed that all plants bid only their fuel and variable O&M costs. It should be noted that the analysis does not capture the true incremental emission impact of a change in usage. The analysis uses emission rates based on steady state operation at full capacity. The effects of equipment ramping on emissions is not considered.

**Table 13: Generic Plant Operating Characteristics**

| Unit | CCGT | Steam Turbine | CT |
|---|---|---|---|
| Heat Rate | 7000 | 10500 | 14000 |
| Gas Price ($/MMBTU) | 2.42 | 2.42 | 2.42 |
| Fuel Cost ($/MWh) | 16.94 | 25.41 | 33.88 |
| Variable O&M ($/MWh) | 3.5 | 3.5 | 4.5 |
| Total Variable Cost ($/MWh) | 20.44 | 28.91 | 38.38 |
| Losses | 3% | 3% | 3% |
| Delivered Cost ($/MWh) | 21.05 | 29.78 | 39.53 |

Fuel cost is in year 2000 dollars for calendar year 2005.

Using the Delivered Cost shown in the last row in Table 13, the plant types are mapped to the hourly generation cost forecast for the year 2005. 2005 was selected because it represents a rough balance of demand and supply resources, and should be indicative of the long-run characteristics of the market. The CT is placed on the margin 10% of the year; the steam turbine in 35% of the year, and the CCGT in 55% of the year[20].

The associated emission costs assigned to each hour depend upon the emission cost scenario chosen. By applying the generic performance values in Table 12 to a couple of emission valuation scenarios from Table 11 to derive $/MWh emission costs by pollutant and plant type in Table 14. The tables show how the emission costs vary by plant type and suggest that emission costs should be developed in a time varying manner.

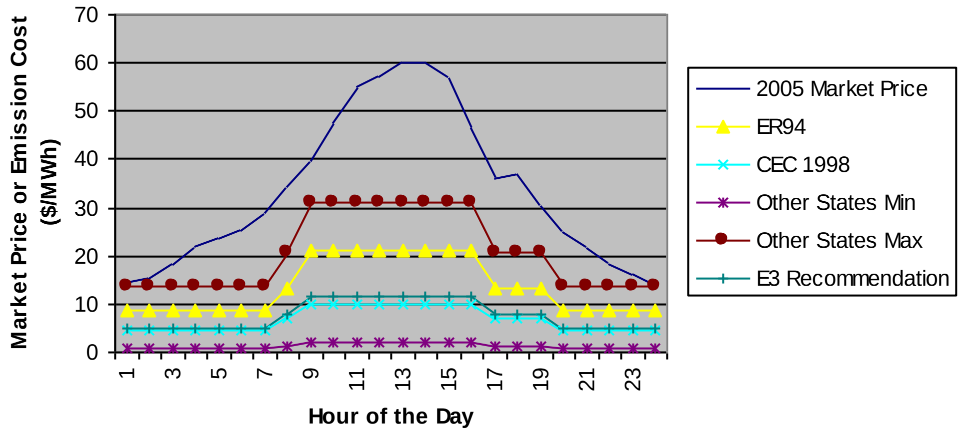
[20] The CCGT is the marginal plant 31% of the year. For all hours with costs below the CCGT, the emission value for the CCGT was also assigned. The reasoning is that much of the resource on the margin during those low cost hours would be hydro plants. Since hydro is largely an energy-limited, rather than a capacity limited resource, the use of the CCGT cost reflects the fact that every MWh of hydro production at that hour is one less MWh of hydro power that can be used to replace fossil plants in another hour. To the extent that the marginal resource in any low cost hour is actually nuclear, hydro running to avoid spill conditions, or run of the river hydro, this assignment of CCGT costs could overestimate the emission costs. However, given the current wide range in the emission cost values, fine-tuning of this low cost hour assumption would not be worthwhile.

**Table 14: Summary of Emission Costs by Cost Scenario and Generic Plant Type ($/MWh)**

| | CEC ER94 | CEC 1998 | Other States Min | Other States Max | TDV Recomm. |
|---|---|---|---|---|---|
| CCGT | 8.56 | 4.57 | 0.88 | 13.8 | 5.1 |
| Steam turbine | 13.26 | 6.96 | 1.33 | 20.9 | 7.95 |
| CT | 21.3 | 10.0 | 2.14 | 30.9 | 11.4 |

A sample mapping for one summer day in 2005 is shown in the figure below. For comparison, the market price forecast for 2005 has also been included.

**Figure 9: Hourly Emission Costs by Scenario ($/MWh)**



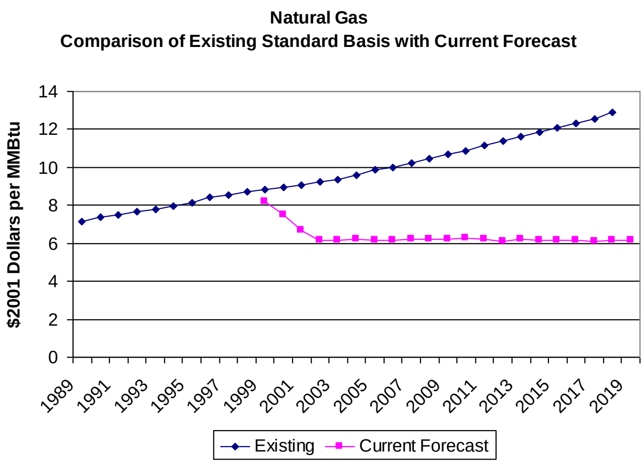

Our recommendation is that the emission cost profile not change across years.

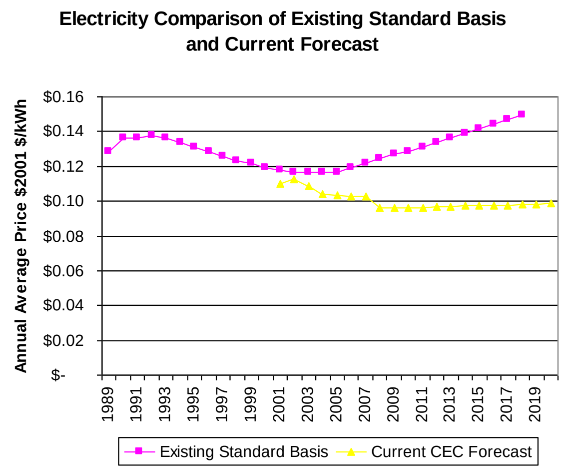
## *10.1.5 1992 Standards Adder*

Current CEC forecasts predict that natural gas (and by extension electricity) prices will drop off as natural gas production is increased. These predictions form the basis of the estimates of electricity and natural gas commodity prices used in this valuation of energy. Even with the inclusion of the recommended values of externalities, the overall value of saving energy would be less, which would tend to reduce standards.

The following two charts compare the natural gas and electricity end-use rate projections (converted to constant 2001 dollars). In both cases, the original projections for energy prices escalated at approximately 3% in real terms in the original forecast developed in 1989, and are relatively constant in real terms in the current projection. Over the course of a 15- or 30-year present value this leads to a large difference. The longer the forecast, the larger the difference. Therefore, the residential standard values (which are based on a 30-year present value) would be more deficient than the commercial standard values (based on 15-years) if the current forecasts were adopted.

**Figure 10: Comparison of Natural Gas and Electricity Price Predictions: Valuation for Standards and Current CEC Forecast**




Given the current uncertainty over energy prices and how the electricity market may finally work, we feel that it is prudent in the short term to "true up" our estimate to the values used to determine the cost-effectiveness of the 1992 Standards. We have applied this adjustment factor as a flat adder of a fixed $/kWh overall hours. The end effect is that the energy valuation would have a time varying component but that the overall real value of energy is equal to that used to develop the 1992 Standards. Thus the energy efficiency standards would have the same overall level of stringency but would shift the emphasis so that measures that reduced electrical consumption on hot summer afternoons would be given more credit than measures that reduced electrical consumption in the middle of the night. The values of this "1992 adder" are contained in Table 1 in the next section.

## 10.2 Total Value of Electricity

By combining all of the above factors we have a time dependent valuation of electricity for a given hour i, $ETDV_i$, as:

$$ETDV_i = \begin{array}{l}(Commodity\ Cost_i) + (T\ \&\ D\ Marginal\ Cost \times PCAF_i) + (Fixed\ \ Cost\ \ Adder) + \\ \qquad (Emission\ Externality_i) + (Adder\ to\ 1992\ level)\end{array}$$

As indicated by the subscripts, the commodity cost, T&D costs and externalities are time varying. The fixed cost adder and the adder to the 1992 level are both constant across all hours of the year.

**Table 15:Summary Statistics on Electricity TDV Costing**

| TDV Lifecycle Cost Components $/kWh | Zone | Oakland | | China Lake | | Fresno | | Long Beach | | Shasta | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **TDV Component** | Class | Res | Com | Res | Com | Res | Com | Res | Com | Res | Com |
| **Commodity Cost** | Min | $0.03 | $0.02 | $0.03 | $0.02 | $0.03 | $0.02 | $0.03 | $0.02 | $0.03 | $0.02 |
| | Avg | $0.75 | $0.45 | $0.74 | $0.45 | $0.75 | $0.45 | $0.74 | $0.45 | $0.75 | $0.45 |
| | Max | $3.14 | $1.91 | $3.13 | $1.90 | $3.14 | $1.91 | $3.13 | $1.90 | $3.14 | $1.91 |
| **T&D Cost** | Min | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | Avg | $0.21 | $0.14 | $0.37 | $0.17 | $0.32 | $0.19 | $0.13 | $0.07 | $0.47 | $0.31 |
| | Max | $95.18 | $61.56 | 129.80 | $82.72 | 150.01 | $97.02 | $73.51 | $45.50 | 637.40 | 412.26 |
| **Rate Adder** | Flat | $1.03 | $0.28 | $0.74 | $0.32 | $0.91 | $0.23 | $1.20 | $0.55 | $0.76 | $0.11 |
| **1992 Standard Adder** | Flat | $0.48 | $0.43 | $0.60 | $0.37 | $0.48 | $0.43 | $0.38 | $0.23 | $0.48 | $0.43 |
| **Environmental Adder** | Min | $0.11 | $0.06 | $0.11 | $0.06 | $0.11 | $0.06 | $0.11 | $0.06 | $0.11 | $0.06 |
| | Avg | $0.14 | $0.09 | $0.14 | $0.09 | $0.14 | $0.09 | $0.14 | $0.09 | $0.14 | $0.09 |
| | Max | $0.24 | $0.14 | $0.24 | $0.14 | $0.24 | $0.14 | $0.24 | $0.14 | $0.24 | $0.14 |
| **Total TDV** | Min | $1.67 | $0.82 | $1.51 | $0.79 | $1.56 | $0.76 | $1.76 | $0.89 | $1.41 | $0.65 |
| | Avg | $2.60 | $1.39 | $2.60 | $1.39 | $2.60 | $1.39 | $2.60 | $1.39 | $2.60 | $1.39 |
| | Max | $97.66 | $62.87 | 132.26 | $84.08 | 152.37 | $98.27 | $76.07 | $46.87 | 639.56 | 413.36 |

# 10.3 Natural Gas Costing Factors

## 10.3.1 Natural Gas Marginal Costs (Commodity and T&D Costs)

The previous discussion has focused on electricity costing, but the other major fuel in California is natural gas. Any TDV methodology must account for this fact. While there is no hourly variation in natural gas costs, there are seasonal and regional differences in costs that must be accounted for in the TDV methodology.

The CPUC and FERC offer publicly available data on utility and/or supplier natural gas costs. Rate filing proceedings yield natural gas transportation and storage marginal costs for the three gas utilities in the State.

### Revision of the Natural Gas Forecast

This revision of the natural gas values makes a number of changes from the existing values used as the basis of the Title 24 Building Standards. Rather than a single value per quantity of natural gas, this valuation has variation by month and area.

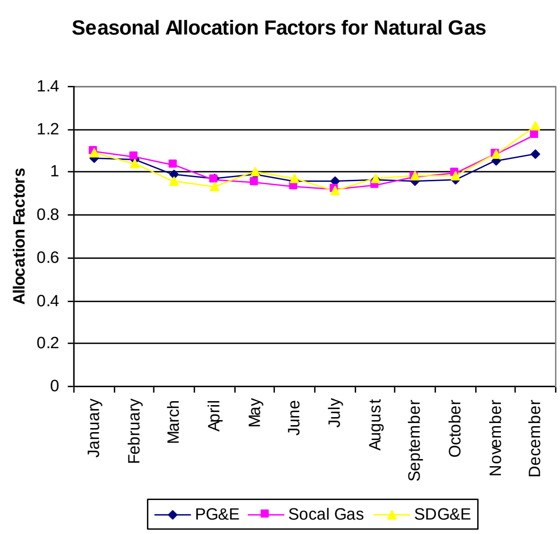
The underlying concept in these values is to reflect the month to month 'shape' of the natural gas commodity purchases, and the 'level' of the natural gas rates. In addition, an environmental externality is applied to reflect the societal value of reduced air pollution on saved natural gas consumption.

The approach is to combine the long run forecast of delivered natural gas prices developed by the CEC and the historical month to month variation in the natural gas commodity and then add the environmental externality. The monthly variation is important for the TDV project because this 'shape' should reflect the relative importance of natural gas conservation from a societal perspective used in developing the building codes.

### Month to Month Variation in Natural Gas Prices

The month to month variation of natural gas marginal commodity cost is based on the variation forecasted for gas delivered to electric power plants[21]. This forecast is used since the price a generator pays is mostly commodity. Therefore the shape reflects the underlying price of natural gas. This is also consistent with the electric price forecast because the same natural gas forecast is used in the development of the electricity forecast.

**Figure 11: Natural Gas Seasonal Allocation Factors**

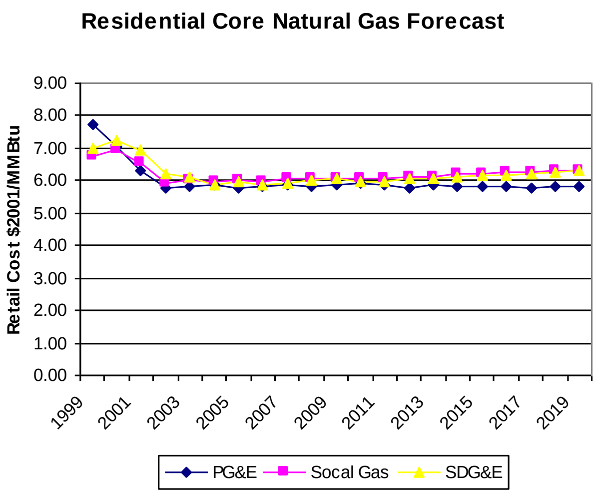


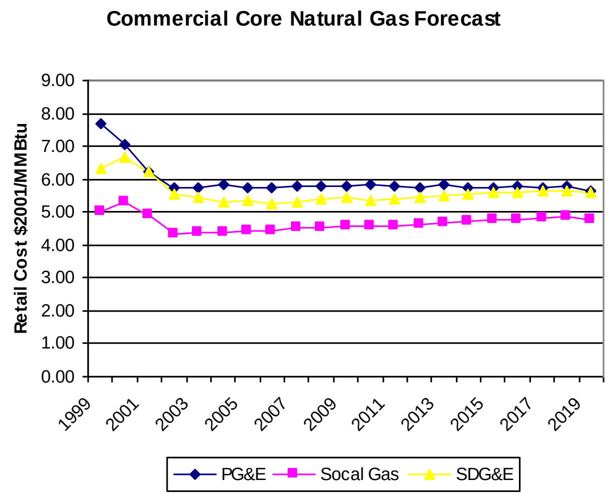

[21] Monthly factors derived from 1987-1997 UMFOR filings for each service area.

### 10.3.2 Long-term Natural Gas Forecast

The following charts show the natural gas price forecast for residential and commercial core customers in each gas service area[22]. They have been adjusted from 1998 to 2001 dollars using the GDP price deflator.

**Figure 12: Long Term Residential and Commercial Natural Gas Price Forecasts**




### 10.3.3 Natural Gas Fixed Costs

As with electricity and natural gas, a flat rate adder is calculated and added to the commodity costs to reflect the average rate level by class. Compared to electricity, natural gas transmission and distribution marginal costs are relatively low. Gas pressure can be increased to increase capacity of gas transmission and distribution as well as storage facilities. Since the T&D costs are flat these are combined with the flat costs associated with taxes, overheads, interest and return on capital, billing and metering and other gas utility. By subtracting the annual average commodity cost from the forecasted annual average gas rates, one is able to obtain the combined flat rate adder for T&D expenses as well as other fixed gas costs.

### 10.3.4 Natural Gas Environmental Externalities

In addition to the natural gas price, an environmental externality is added to reflect societal benefits of reduced air pollution. The range of value of reduced air emissions is given in Section 10.1.4 Electricity Environmental Externalities (Air Emissions Value).

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[22] Forecast of retail gas prices is from California Energy Commission, Natural Gas Market Outlook: 2000 - 2020

**Table 16: Comparison of Externality Costs for Carbon Dioxide and Nitrogen Oxides ($/Ton)**

| Externality Cost $/Ton | CO2 | NOx |
|---|---|---|
| ER94 | $ 9 | $ 9,120 |
| CEC Internal 1998 Estimate | $ 9 | $ 1,800 |
| Other States Min | $ 1 | $ 850 |
| Other States Max | $ 24 | $ 7,500 |
| TDV Recommendation | $ 9 | $ 3,000 |

The assumed rate of air emissions from the combustion of natural gas for commercial and residential applications is 0.0145 [Metric Tons Carbon/MMBtu] = 0.058 [short ton CO2/MMBtu] and 0.045 [lb NOx/MMBtu]. At the range of emissions values, this gives the following externality cost scenarios.

**Table 17: Comparison of Externality Values Associated with On-Site Combustion of Natural Gas**

| Scenario | $/MMBtu | 15 Year NPV | 30 Year NPV |
|---|---|---|---|
| ER94 | $ 0.73 | $8.94 | $14.68 |
| CEC Internal 1998 Estimate | $ 0.56 | $6.92 | $11.36 |
| Other States Min | $ 0.08 | $0.95 | $1.56 |
| Other States Max | $ 1.56 | $19.19 | $31.51 |
| TDV Recommendation | $ 0.59 | $7.25 | $11.90 |

### *10.3.5 Natural Gas TDV Values*

Compared to electricity, natural gas transmission and distribution marginal costs are relatively low. Gas pressure can be increased to increase capacity of gas transmission and distribution as well as storage facilities. Since the T&D costs are flat these can be combined with the flat costs associated with overhead and profit so that the cost calculation is easier. By subtracting the annual fuel cost from the annual gas rate, one is able to obtain the combined flat cost for T&D as well as gas utility fixed costs. To obtain the total time dependent values of natural gas, the following components of gas costs are added to the T&D costs and the utility fixed costs:

- Monthly gas costs as described in Section 10.3.1
- A flat (constant with respect to time of day or year) adder so the total value of natural gas matches the real value of natural gas used to develop the 1992 California efficiency standards. This adder helps maintain the overall stringency and stability of the standards.
- Externality costs as described in the preceding section

Thus the TDV natural gas values are computed with the following equation:

$$TDV\ Value\ \{month, year\} = \begin{array}{c} Monthly\ Fuel\ Cost\{month, year\} + \\ Emission\ Externality\{year\} + Adder\ to\ 1992\ Value + \\ (Annual\ Ave.Total\ Rate\{year\} - Annual\ Ave.FuelCost\{year\}) \end{array}$$

The following table summarizes the components of time dependent costs that have been developed for natural gas.

**Table 18: Summary Statistics for Natural Gas TDV Costs**

| TDV Lifecycle Cost Components $/MMBtu | Zone | PG&E | | Socal Gas | | SDG&E | |
|---|---|---|---|---|---|---|---|
| **TDV Component** | Class | Res | Com | Res | Com | Res | Com |
| **Commodity Cost** | Min | $56.02 | $31.46 | $53.26 | $29.62 | $53.01 | $29.48 |
| | Avg | $60.03 | $33.41 | $59.91 | $32.91 | $59.78 | $32.90 |
| | Max | $63.44 | $35.63 | $67.77 | $37.69 | $70.31 | $39.11 |
| **Rate Adder** | Flat | $62.55 | $40.79 | $70.52 | $25.22 | $70.54 | $37.03 |
| **1992 Standard Adder** | Flat | $53.73 | $5.04 | $45.88 | $21.12 | $45.98 | $9.31 |
| **Environmental Adder** | Flat | $11.90 | $7.25 | $11.90 | $7.25 | $11.90 | $7.25 |
| **Total TDV** | Min | $184.19 | $84.55 | $181.56 | $83.20 | $181.43 | $83.07 |
| | Avg | $188.20 | $86.49 | $188.20 | $86.49 | $188.20 | $86.49 |
| | Max | $191.61 | $88.71 | $196.07 | $91.27 | $198.73 | $92.69 |

## 10.4 Propane Costing Factors

This section describes the derivation of a forecast of propane prices by month for residential and commercial customers for use in developing the new revision of the building standards.

Total propane costs for this valuation are the sum of:

- Wholesale prices - projected from forecasts of crude oil price
- Rate adder - the difference between wholesale and retail prices.
- Environmental externalities - the same valuation for NOx and $CO_2$, that was used for applying externalities values to natural gas and electricity consumption, is applied to the expected emission of these pollutants from propane combustion.

There is no adder to bring the propane valuation up to levels used to develop the 1992 energy efficiency standards, because propane was not specifically costed in the development of the 1992 standards.

### *10.4.1 Change from the Existing Standards*

In the current building standards, conservation of propane is treated as having the same value as conservation of natural gas. However, propane and natural gas have very different prices. Propane costs roughly twice as much per MMBtu as natural gas. In addition, the relative values between fuels and electricity were different for development of the standards and the values used in the Alternative Compliance Method (ACM) software. If implemented in its entirety, the TDV method would be apply specific time varying costs to each energy source (electricity, natural gas and propane) and the same values used in the development of standards would also be applied to the Alternative Compliance Method (ACM) software.

### *10.4.2 Commodity Costs*

**Propane Follows Crude Oil Prices.** Since a long-term forecast of propane prices is not available, we have used the price of crude oil as a proxy. The Department of Energy analyst at the EIA, Alice Lippert, presented the following chart that compares the price of crude oil with propane[23]. Based on this correlation she suggests using a long-term forecast of crude oil to estimate the price of propane. The price of propane and crude oil are related because propane is a byproduct of refining crude oil. Although crude oil and propane prices are highly correlated, the EIA presentation notes that “because there are different sectors competing for demand of propane, price movements can be more exaggerated.”

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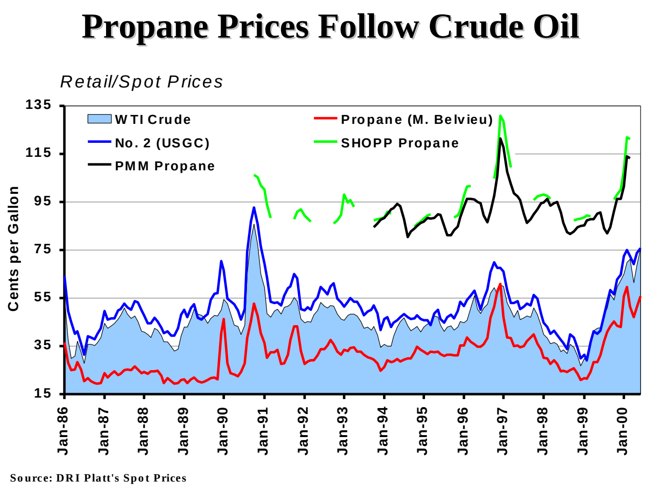
[23] Alice Lippert, Petroleum Division, Energy Information Administration, Coalition of Northeastern Governors, July 26, 2000. http://www.eia.doe.gov/pub/oil_gas/petroleum/presentations/2000/propane_market_status_report/index.htm

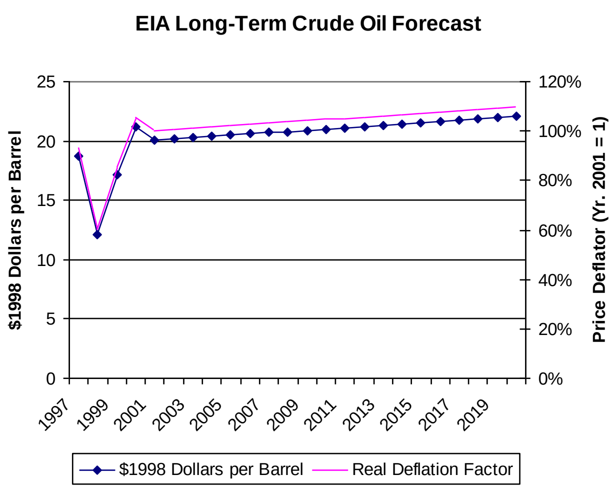
(202)586-9600 phone, alice.lippert@eia.doe.gov

**Figure 13: Relationship between Propane and Crude Oil Prices**




From the DOE price forecast, a set of price deflators are calculated relative to the 2001 price. To develop a forecast of propane, these deflators are applied from the peak price observed in February 2000. With this method, the price trend of propane exactly mirrors the long-term forecast of crude oil.

**Table 19: DOE/EIA Long Term Crude Oil Forecast**[24]

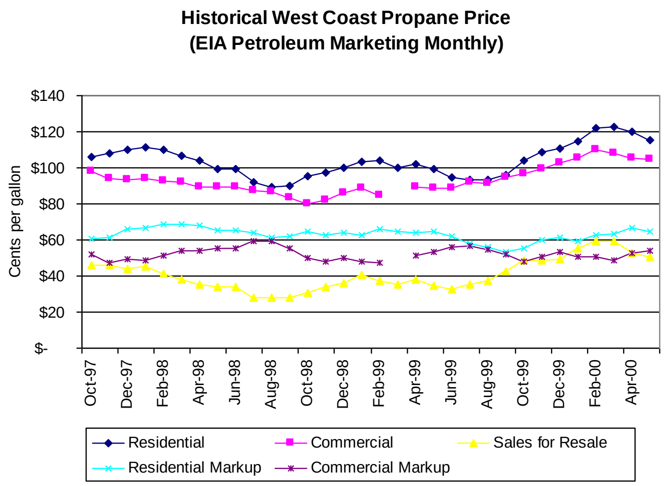



[24] Annual Energy Outlook 2000, Table 1, EIA, Report#:DOE/EIA-0383(2000) **December 17, 1999.** http://www.eia.doe.gov/oiaf/aeo/aeotab_1.htm. Contact Douglas Macintyre, Douglas.Macintyre@eia.doe.gov

### 10.4.3 Propane Commodity Seasonal Variation

The following chart shows the historical propane prices for the last two years. Average delivered retail prices by month are provided for residential customers, and commercial customers, as well as the 'sales for resale' which is the price paid by distributors for propane[25]. Over the last three years propane prices (both wholesale and retail) have followed the seasonal heating demand with the highest prices occurring in January or February.

**Figure 14: Trends in Propane Pricing**




### 10.4.4 Propane Fixed Costs

The residential and commercial rate adder is the difference between prices to distributors and the retail price and would include all costs of operating local distribution companies, and any profits. Looking at historical data, this adder is relatively flat seasonally compared to the commodity propane price. The average residential and commercial adders are 63 and 52.1 cents per gallon respectively. The following table provides the average and standard deviation of the rate adder.

**Table 20: Difference Between Wholesale and Retail Propane Prices**

| Cents per Gallon | Residential Adder | Commercial Adder |
|---|---|---|
| Average | 63.0 | 52.1 |
| Standard Deviation | 3.7 | 3.3 |

### 10.4.5

[25] Information compiled from Petroluem Marketing Monthly publications, Table 38. January 1998 through September 2000. http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_monthly/historical/2000/2000_09/pmm_2000_09.html

### 10.4.6 Propane Environmental Externalities

In addition to the natural gas price, an environmental externality is added to reflect societal benefits of reduced air pollution. The range of value of reduced air emissions is the same as given in Section 10.3.4 for natural gas externalities. For a more detailed description see Section 10.1.4 Electricity Environmental Externalities (Air Emissions Value).

The assumed rate of air emissions from the combustion of natural gas for commercial and residential applications is 0.0175 [Metric Tons Carbon /MMBtu] = 0.07 [Short Ton-$CO_2$/MMBtu] and 0.045 [lb NOx/MMBtu]. At the range of emissions values, this gives the following externality cost scenarios.

**Table 21: Range of Externality Estimates of Propane Combustion**

| Scenario | Annual $/MMBtu | 15 Year NPV | 30 Year NPV |
|---|---|---|---|
| ER94 | $ 0.84 | $10.27 | $16.86 |
| CEC Internal 1998 Estimate | $ 0.67 | $8.24 | $13.54 |
| Other States Min | $ 0.09 | $1.10 | $1.80 |
| Other States Max | $ 1.85 | $22.73 | $37.32 |
| TDV Recommendation | $ 0.70 | $8.58 | $14.08 |

### 10.4.7 Final Retail Price Forecast

With the historical propane price shapes and a long-term forecast, a long-term retail price forecast for propane is developed. The price in each year is calculated as follows:

$$TDV\,Value\{year, month, class\} = \begin{array}{c} Average\ Annual\ Wholesale\ Price \times Deflation\{year\} \times \\ Seasonal\ Factor\{month\} + Rate\ Adder\{class\} + Environmental\ Externality \end{array}$$

Where;

Peak 2000 Wholesale Price is the observed wholesale price in February of $59.2 cents per gallon adjusted to 2001 dollars by applying the GDP price deflator of 1.004273811.

Deflation {Year} is the annual price adjustment based on the EIA crude oil forecast.

Season Factor {Month} is the monthly variation from the peak commodity price.

Rate adder is the average difference between wholesale and retail costs

Environmental Externality is the value of reduced emissions from propane conservation.

### 10.4.8 Present Value of Propane Conservation

The following table contains the present value of propane conservation for residential and commercial usage. All values are given in 2001 dollars. The existing standards use a 15-year present value for commercial buildings, and a 30-year present value of residential buildings. Present value has been calculated with a 3% real discount rate[26].

**Table 22: Summary Statistics for Propane TDV Costs**

| TDV Lifecycle Cost Components $/MMBtu | Class | Res | Com |
|---|---|---|---|
| Commodity | Min | $115.87 | $50.93 |
| | Avg | $128.95 | $53.97 |
| | Max | $137.89 | $58.51 |
| Rate Adder | Flat | $117.42 | $82.96 |
| Environment | Flat | $14.08 | $8.58 |
| Total TDV | Min | $247.38 | $142.47 |
| | Avg | $260.46 | $145.51 |
| | Max | $269.39 | $150.04 |

[26] This is the same assumption as the current standard. See Summary of Cost-Effectiveness, March 29, 1990, Jon Leber P.E., California Energy Commission.