New California PUC Avoided Costs for Energy Efficiency Evaluation

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ABSTRACT

This paper describes the new avoided cost estimates developed by the California Public Utility Commission (CPUC), the fundamental methodology for developing the estimates, and the guiding principles of their development. The new avoided costs are an update to the CPUC's *Energy Efficiency Policy Manual* and apply to efficiency programs funded with the electricity and natural gas Public Goods Charge (PGC) funds. The paper concludes that time- and area-varying avoided cost estimates can provide more accurate signals to guide investment in energy efficiency than do statewide average avoided costs. California has proposed new avoided costs based on this principle, and similar updates to avoided costs could be made for other states with their own climates, markets, and customers.

Introduction

In the restructured California energy market, efficiency programs perform the critical function of directing investments into cost-effective, sustainable energy savings that are not adequately addressed by market forces alone. These programs are funded by the electric Public Goods Charge (PGC) and natural gas Demand-Side Management (DSM) charge. The CPUC oversees the expenditure of about $285 million annually on energy efficiency programs by the four investor-owned utilities in California: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), Southern California Gas Company (SoCal Gas), and San Diego Gas & Electric (SDG&E). In addition, the utilities were granted approximately $244 million over two years for procurement energy efficiency, bringing the annual total spent on energy efficiency to about $400 million.

Many of these programs are evaluated and selected based on their cost-effectiveness, which in turn is based on a comparison of a measure's costs and the "avoided costs" the CPUC uses to value the energy saved by each measure. The term "total avoided cost" refers to the marginal cost avoided by society through a reduction in energy usage, which can be either electricity or natural gas. For the evaluation of cost-effectiveness, the avoided cost is the societal benefit of conservation. Therefore, the accuracy of the avoided costs used is crucial.

The CPUC's current set of avoided costs consist of statewide average estimates (CPUC 2003).[3] However, this approach contained insufficient delineation by time-of-use (TOU) period or area necessary for program evaluation in the post-reform market environment. To correct this, the CPUC in 2003 sponsored the development of a new framework for avoided costs to update

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[3] The CPUC's existing avoided costs are based on Aug. 2000 CEC electricity and gas price forecasts and a statewide average of weighted forecasts of T&D costs (based on 1996 utility sales for electricity, PY2000 values for gas).

the existing values in the *Energy Efficiency Policy Manual* (the *Policy Manual*). The new avoided costs establish a forecast for the years 2004-2023. The benefits of conservation are computed as the sum of the following components:

1. Electricity and natural gas commodity, adjusted for energy losses.
2. Environmental externality, which quantifies the reduced impact on the environment resulting from less generation of electricity and direct combustion of natural gas.
3. Transmission and distribution (T&D) capacity, which captures the reduced demand-related capital expenditures, line capacity losses and maintenance costs associated with energy savings.
4. System reliability, which includes the cost of maintaining a reserve margin and other ancillary services.
5. Price effect of demand reduction, which recognizes that reduced demand results in a decrease in the market-clearing price for electricity.

A draft of the complete methodology and results is posted on the CPUC's website.[4] The resulting avoided costs are appropriate for applying the "Total Resource Cost (TRC) test – Societal Version" which is the primary cost-effectiveness test for California efficiency programs (CPUC 2003). This test, as defined in the *Standard Practice Manual* (CPUC 2001), is intended to measure the overall cost-effectiveness of energy efficiency programs from a societal perspective, taking into account benefits and costs from a wider perspective as opposed to one individual or stakeholder.

The remainder of this paper describes the CPUC's process, guiding principles and fundamental methodology for developing the new avoided cost estimates. The paper compares the new disaggregated avoided cost forecasts to the existing values so that the reader is able to answer three main questions; "What do the new avoided costs look like?", "How are they different from the previous values?", and "Why does it matter?"

Process

The CPUC and its consultant, Energy and Environmental Economics, Inc. (E3), followed an open and inclusive approach with reference to stakeholders throughout the development of the recommended avoided cost values. The team's efforts to develop a sound analytical process benefited directly from the close collaboration and valuable input of the CPUC, the Office of Ratepayer Advocates, the California Energy Commission (CEC), California's four investor-owned utilities, and the Natural Resources Defense Council.

The team progressed through the following steps from August 2003 through June 2004:

1. Five meetings attended by the parties mentioned above (August September 2003). Each meeting focused on E3's proposed methodology for a specific avoided cost or adder. Feedback was welcomed during and after each meeting, and E3 modified the methodologies accordingly.
2. Presentation of preliminary results (November 2003) for the avoided cost components to the parties, followed by another comment period.

[4] Online: http://www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/cpucdraft01082004.pdf

3. A written draft report with results (December 2003), detailed descriptions of methodologies, and data, followed by yet another comment period.
4. A final report with software incorporating comments (January 2004).
5. Public workshops on proposed avoided costs (expected June 2004, as of this writing).

Guiding Principles

The CPUC and E3 followed four guiding principles in developing the avoided cost forecasts. First, the team sought to develop a transparent methodology that relied on only readily or publicly available data, so as to allow independent review by numerous stakeholders. Second, the CPUC wanted a flexible approach that could be updated to reflect changes in the major cost drivers or modified for other applications. Third, the stakeholders agreed to utilize forward market prices whenever possible, instead of a production simulation costing model of hourly marginal energy costs plus an annual T&D value. Market prices reflect the collective best estimate of the value of a commodity. Finally, the avoided costs needed to be able to reflect "stress" cases, such as poor hydro conditions and high gas prices.

Methodology

Table 1 summarizes the methodologies and data sources for each of the avoided cost components developed by the CPUC, in keeping with the principles above. By "market period" we mean the period of time when forward market prices or futures prices are available.

Table 1. Avoided Cost Components and Data Sources

Avoided Component	Description
Electricity Capacity and Energy (with losses)	Market-based value of electricity procurement in Northern CA & Southern CA • *Electricity Market Period:* Forward market prices for electricity. • *Transition Period:* Extend electricity market prices with natural gas futures • *Post-market Period:* Long-run marginal cost (LRMC) of a combined cycle gas turbine estimated by the CEC. Long-run CEC natural gas forecast • Loss factors from utility filings to the CPUC.
Natural Gas Commodity (with losses)	Market-based value of gas procurement in Northern CA & Southern CA • *Market Period:* Forward market prices from NYMEX, adjusted to PG&E and SoCal city gates by adding (or subtracting) a basis differential calculated using historical data. • *Post-market Period:* CEC's long-run forecast of natural gas prices. • Loss and compression fuel factors from utility filings to the CPUC.
Environmental Externality	Market-based price of air emissions from California plus an estimated emission cost for CO2 • NOx, SOx, PM10: Included in market price during the Market Period. Added to the LRMC estimate in the Post-market Period using CA Air Resources Board data. • CO_2: Added throughout study horizon at $8/ton based on a price survey.
Transmission and Distribution	Cost of constructing additional T&D capacity to meet customer peak demands growth. Costs are based on utility capital and load forecasts in filings with the CPUC and FERC. • For electricity, the T&D capacity avoided costs vary by sub-area within the utilities. Capacity costs also vary by hour, coincident with the timing of the local area peak demands. Peak demand is correlated to local weather conditions. • For natural gas, the T&D avoided costs vary by utility service territory and are allocated to the winter season (November through March)
Reliability Externality	Costs associated with delivering firm reliable electricity to the utility T&D system. Computed from historical ancillary services cost data collected by the CA Independent System Operator.
Price Effect of Demand Reduction	Reduction in total spot market purchase costs attributable to reduction in demand curve. Elasticities calculated using CA Power Exchange day-ahead hourly unconstrained price data.

The new avoided cost methodology has three distinct advantages that fit well with the guiding principles: (1) it uses transparent assumptions; (2) updates to the Excel spreadsheet model are simple and straightforward; and (3) the software is not proprietary. Below, we briefly describe the methodology for calculating each avoided cost component.

Electricity capacity and energy. The stakeholders agreed to use a long-term forecast that relies on transparent electricity and natural gas market prices for the period between 2004 and 2008 when such data are available, and the long-run incremental costs of adding new resources over the remainder of the forecasting period.[5] The avoided cost estimates can be updated and verified by all stakeholders whenever changes in market conditions are observed. The avoided costs are allocated to each hour of the year based on historic market data.

Natural gas commodity. During the Market Period (January 2004 – October 2009), monthly natural gas avoided costs are derived from NYMEX gas futures prices. The Henry Hub market is used because it is the most liquid market in the country and correlates with the PG&E and SoCal city-gate gas prices. The Henry Hub prices are adjusted to the city-gate prices by adding (or subtracting) a basis differential calculated using historical data. Avoided costs in the Post-market Period are based on the CEC's long-run forecast of gas prices and the monthly shape expressed in the last year of the NYMEX market data.

Environmental benefit. We developed statewide environmental avoided costs by multiplying the costs per pollutant (on a yearly basis) by the emission rate (per hour of the year). The nitrogen oxides (NOx) and particulate matter (PM10) costs in $/MWh are based on California offset prices generators must pay for NOx and PM10 emissions, respectively. The estimated emission rates are based on the implied heat rate in each hour given the hourly electricity and gas prices. We assume that offset prices are included in forward market prices, and are not added in until the Post-market Period. The CO_2 costs ($/MWh) are an estimate of avoided costs for reduction in CO_2 per MWh saved at the customer site. There is no requirement to purchase CO_2 offsets in California, so the avoided cost of the CO_2 emissions is based on prices in other markets. The estimates are long-run averages added in all years of the forecast horizon.

Electricity T&D benefit. These avoided capacity costs are an estimate of the future avoidable delivery costs. Using utility forecasts of proposed T&D investments necessary to meet peak load growth contained in rate case filings, E3 estimated the avoided costs for each utility by planning area and climate zone using the present worth method (E3 & Pacific Energy Associates 2000).[6] A planning area is a sub-area of a utility service territory for distribution planning purposes. The avoided costs were allocated to individual hours based on temperature and grossed up for capacity losses, depending on the voltage level of the end-user.

Natural gas T&D benefit. These costs represent an estimate of marginal transportation cost for delivering gas to "core" residential and commercial end-users. This cost is not the same as the embedded cost of gas delivery the distribution company charges non-core customers. The

[5] The long-run incremental costs were developed using assumptions for the all-in costs of a CCGT in the CEC Staff Report's *Comparative Cost of California Central Station Electricity Generation Technologies,* (August 2003).
[6] This method computes the deferral value based on the difference of utility revenue requirement.

marginal gas transmission cost is not based on peak throughput, but rather the average delivery cost per therm based on the usage profile for each class. The T&D allocation assigns the natural gas capacity cost to the winter season based on the volumetric throughput on each utility system. No T&D capacity costs are assigned to the summer months when gas volumes are lower.

Ancillary services. These are the costs incurred by the California ISO to reliably operate the grid. The CAISO's Division of Market Analysis (DMA) reports monthly average ancillary service prices as a percent of total energy costs. Rather than duplicate this effort, E3 calculated the ancillary service multiplier as 1 plus the average of the monthly values reported by the DMA.

Price effect of demand reduction. The economic rationale is that demand-side-management (DSM) and energy efficiency (EE) programs reduce the electricity demand of program participants and shift the market demand curve downward along a given market supply curve, thus effecting a price reduction that can benefit all electricity consumers. When a utility relies entirely on the spot market for its procurement needs, a multiplier magnifies the generation avoided cost by a factor equal to (1 + market clearing price (MCP) elasticity), since the entire load is affected by the price decrease (Woo & Lloyd 2001). Now that California's utilities are procuring the vast majority of their power through forward contracts, the amount of energy purchases affected by the market clearing price elasticity is much smaller, and the resulting multiplier is much smaller. Using California Power Exchange data (Apr. 1998 – Apr. 2000), the price effect of demand reduction is estimated to add 8% to the energy value in the on-peak period (0% in the off-peak) in 2004, then decreases over time to reflect the California market returning to resource balance (sufficient capacity) by 2008.

Variation by Area and Time

One of the key differences between the CPUC's new avoided cost forecasts and previous values in California is segmentation of the avoided costs by hour of a typical year and by planning areas and climate zones within the State. The new avoided costs are the second major effort of this type in California for efficiency evaluation. In 2003, the CEC adopted a 'Time Dependent Valuation' (TDV) methodology into the 2005 Title 24 Building Standards (Heschong Mahone Group & E3 2002).[7] The TDV concept is that energy efficiency measure savings should have unique area- and time- specific (ATS) values to better reflect the true avoidable costs to users, to the utility system, and to society. The CEC and CPUC's avoided costs are similar and capture significant differences in avoided costs due to weather, local capacity-demand conditions, and investment plans at times of peak demand. Together, the new CPUC avoided costs and the CEC TDV avoided costs cover new construction standards, and new and retrofit efficiency measures within the State. One of the differences is that the CEC's avoided costs do not include an estimate of demand elasticity.

Table 2 displays how the CPUC has incorporated ATS dimensions of the various avoided costs and adders into its methodology and results.

[7] Title 24 refers to the Energy Efficiency Standards for Residential and Non-Residential Buildings in California. The TDV values are applied using the Alternative Calculation Methdology (ACM), PG&E was the lead contractor to the CEC on the TDV evaluation. Available on internet: http://www.energy.ca.gov/2005_standards/

Table 2. Time and Area Dimensions of Avoided Costs and Externality Adders

Avoided Cost Stream	Time Dimension	Area Dimension
Avoided Electricity Commodity	Hourly by year (8760 hours x 20 years)	Utility specific
Avoided Electric T&D	Hourly by year (8760 hours x 20 years)	Utility, planning area and climate zone specific
Avoided Natural Gas Procurement	Monthly (12 months x 20 years)	Utility specific
Avoided Natural Gas T&D	Monthly (12 months x 20 years)	Utility specific
Environmental Adder	Hourly by year (8760 hours x 20 years)	System-wide (uniform across state)
Reliability Adder	Hourly by year (8760 hours x 20 years)	System-wide (uniform across state)
Price Elasticity of Demand "Multiplier"	Hourly by year (8760 hours x 20 years)	System-wide (uniform across state)

The allocation of costs to area and time can have a dramatic effect on the level of avoided costs for efficiency measures that target the peak. In contrast to past avoided costs summarized by time-of-use (TOU) period, the CPUC's new forecast provides a value of energy and capacity savings for each hour of the year (8,760 values) for each distribution planning area in the State. The statewide annual average values of the new avoided costs are similar to past avoided costs, but a few high cost hours and regions have particularly high avoided costs (for example, a constrained area during the summer peak).

In Figure 1, below, we show an example of the hourly avoided costs for a three-day period during the summer in the San Jose planning area within PG&E. We drew this 3-day example from the 365 data set for this planning area within this climate zone. All told, we have calculated each of the avoided cost components for 16 different climate zones and 25 utility planning areas. The higher value periods during the three summer days are shown by the three peaks. During the first day, there is a significant value for avoided distribution cost, a moderate amount in the second day, and none in the third day. The distribution avoided cost is based on expected local distribution peak loads calculated based on Typical Meteorological Year (TMY) data for the climate zone. Ancillary services, the price elasticity of demand (multiplier) and environment benefits are also higher during the on-peak period.

Figure 1. Forecast Avoided Costs in San Jose over a 3-Day Period in July

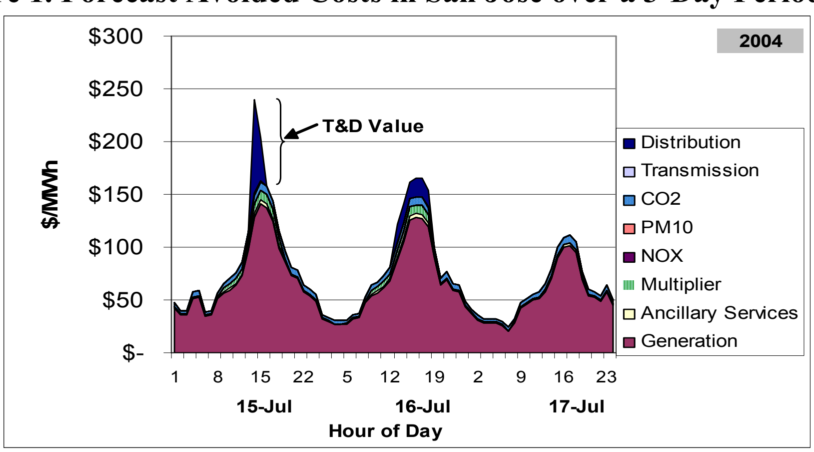


Figure 2 shows the variation in electricity T&D avoided costs by utility planning area across the State, in $/kW-year. The white areas in Kern and Ventura counties, near Los Angeles and on the San Francisco Peninsula have relatively low avoided T&D costs of up to $26.69/kW-yr, whereas PG&E's North Valley and Stockton planning areas, and the SDG&E service territory, have avoided costs ranging from $53.30 to $80/kW-yr. Differences in climate, population density, load growth, and a planning area's stage in the T&D investment cycle all lead to a wide range in T&D avoided costs by area.

Figure 2. Map of California T&D Avoided Costs by Utility Planning Area

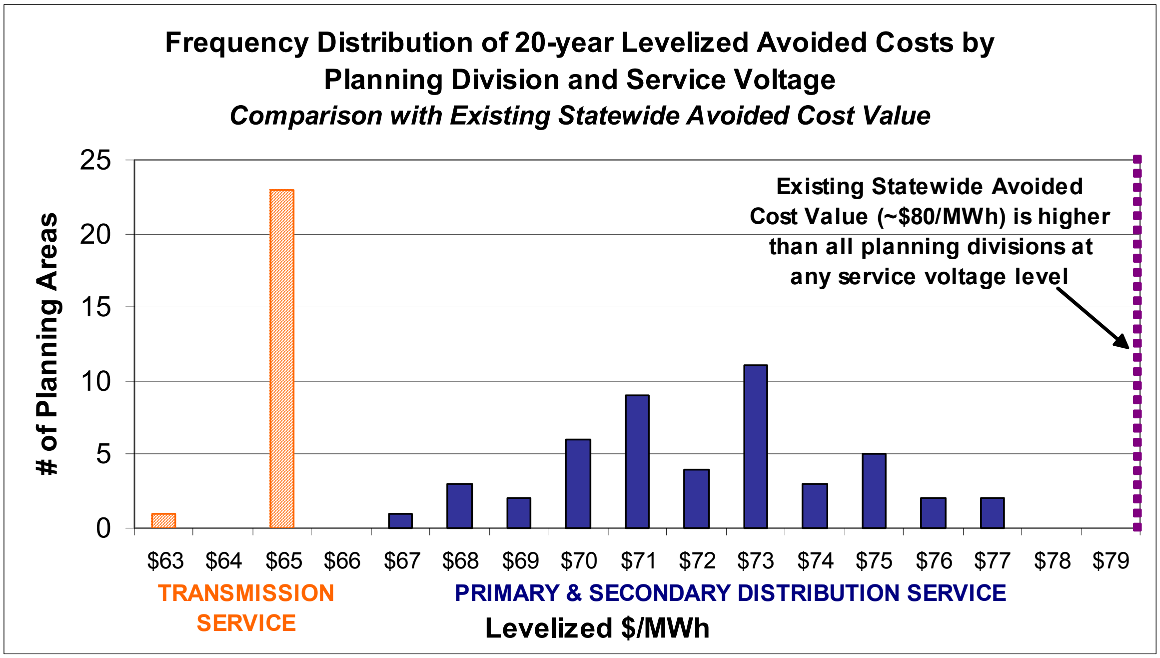
New and Existing Electricity Avoided Costs

Whereas the CPUC's existing electricity avoided costs are annual, statewide forecasts, the new forecast avoided costs vary by both area and time. In fact, for electricity, we have calculated the avoided costs by hour for each year for the 16 climate zones, 25 electric utility planning areas, and three service voltage levels (transmission and primary and secondary distribution). This level of segmentation reveals important differences in avoided costs that are useful for designing targeted DSM programs.

Figure 3 shows the approximate range of the new levelized avoided cost forecasts by planning area and service voltage level for 2004-2023 compared to the CPUC's existing value.

The figure shows that most of the new primary and secondary service voltage area- and time-specific avoided costs (in 2004 dollars) fall between $70 and $75/MWh. However, the avoided costs at the transmission service level do not include distribution costs; therefore, they range from $63 to $65/MWh. Although the costing data and methodologies are substantially different, the new forecast costs are remarkably close to the CPUC's existing levelized forecast of about $80/MWh. The mode of the new distribution-level electricity avoided cost forecasts ($73/MWh) is about 10% lower than the CPUC's existing levelized value.

Figure 3. Frequency Distribution of New 20-Year, Levelized, Electricity Avoided Costs (2004-2023) by Planning Area and Service Voltage, Compared to Existing Costs



In Figure 4, we show the new avoided costs by hour and month for the San Jose planning area (secondary service voltage). The vertical axis in Figure 4 shows the total avoided cost in levelized $/MWh. The total avoided costs can reach $240/MWh during peak afternoon hours from August to October, with up to $140/MWh of the avoided cost due to the allocation of T&D costs to peak hours. Even though the average annual value of energy savings is less than the existing avoided cost (as shown in Figure 3), allocating the costs to hours results in significantly higher costs in some summer hours.

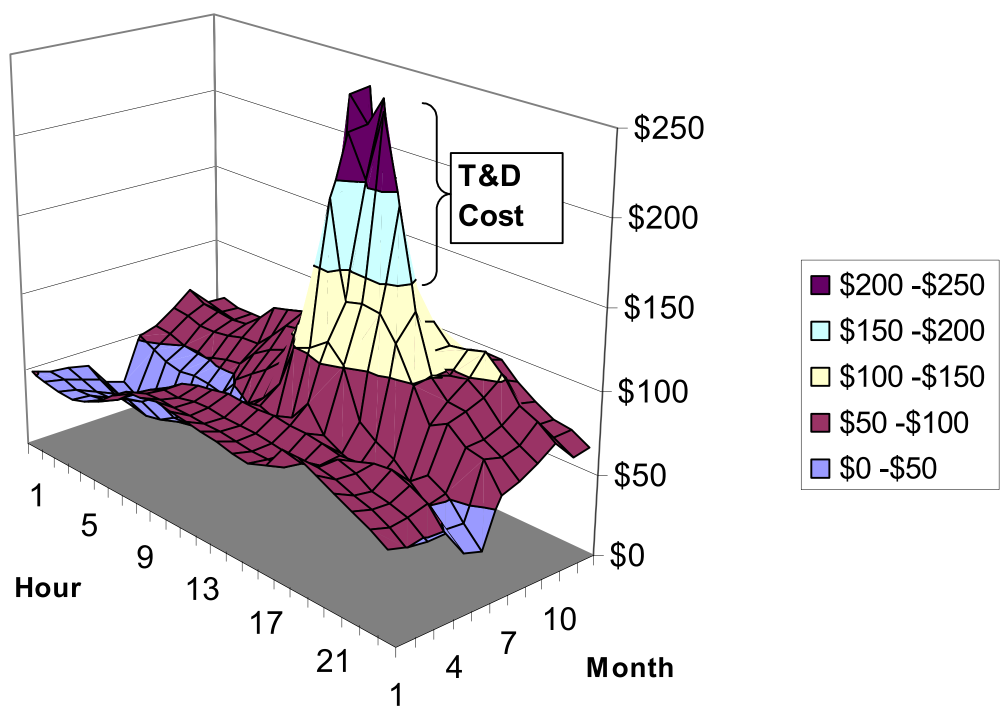
Natural Gas Avoided Cost Comparison

On an annual average basis, the CPUC's new natural gas avoided costs are significantly higher than the existing ones. The increase is approximately $0.08 to $0.15/therm from 2004 through 2010, and $0.15 to $0.20/therm after 2011.

In Figure 5, we compare the new and existing levelized avoided costs by month. The vertical axis shows the levelized avoided costs in $/therm. The flat horizontal line of

$0.54/therm is the 20-year levelized value of the existing avoided costs. The higher, curved line represents the monthly levelized shape of the new avoided costs. We allocated all the T&D costs in the new avoided costs to the winter period (November through March) when demand normally peaks. In combination with the higher commodity costs in the winter months, the new avoided costs are about $0.22/therm higher than the current annual average savings values. In the summer months, the new avoided costs are approximately $0.06/therm higher.

Figure 4. San Jose Levelized Avoided Cost by Month and Hour (Secondary Voltage)



Evaluation of Example Electric and Gas Measure Results

In the new avoided costs, we disaggregated by time, which results in those measures that save more energy during peak periods having significantly more value than those that save energy in the off-peak periods compared to the existing costs. We compared multiple measures to show how the new avoided costs are expected to change the results of the cost-effectiveness evaluation.

In Figure 6, we compare the results for three example electricity efficiency measures: an air conditioning measure, an outdoor lighting measure, and a refrigeration measure. For each measure, we show the weighted average avoided cost for the existing and new avoided cost value. All measures are expected to provide savings for 16 years, beginning in 2004. The air conditioning measure (upgrade of a residential A/C unit from 12 to 13 seasonal energy efficiency rating, or SEER) has an average avoided cost savings of $138/MWh with the new avoided costs as compared to a savings of approximately $78/MWh using the existing avoided costs. The large differential is due to the fact that the majority of the savings in an A/C upgrade occurs during the summer peak period when the value is highest. In contrast, the value for outdoor lighting efficiency drops when applying the new avoided costs from $78/MWh to approximately $60/MWh because outdoor lighting programs target off-peak hours. Finally, refrigeration, which has a flat energy savings profile, remains about the same under both sets of avoided costs.

Figure 5. Comparison of the New and Existing Natural Gas Avoided Costs for a Commercial Boiler in SoCal's Service Territory

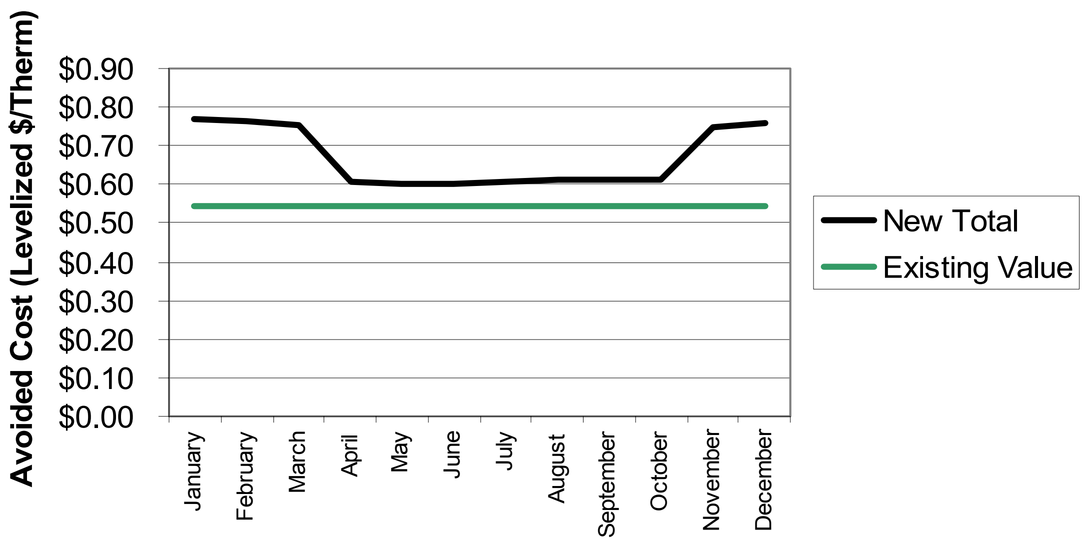
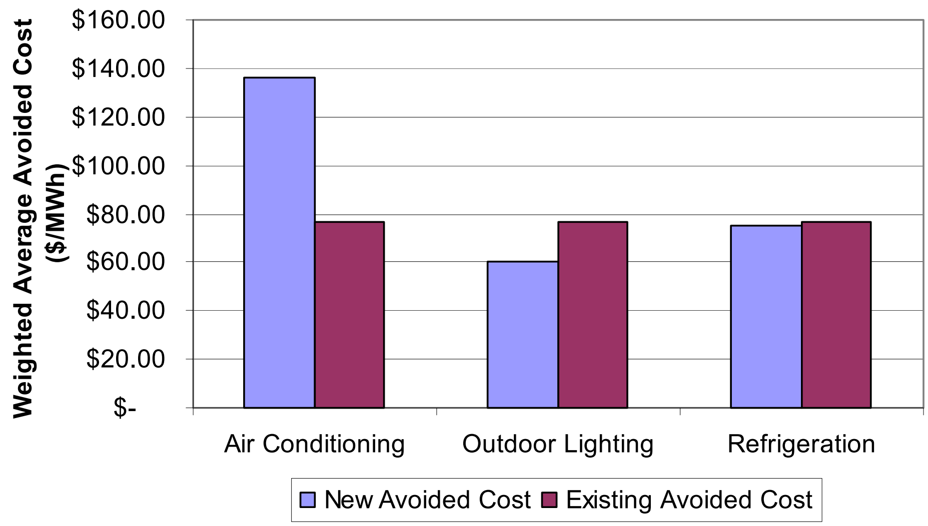
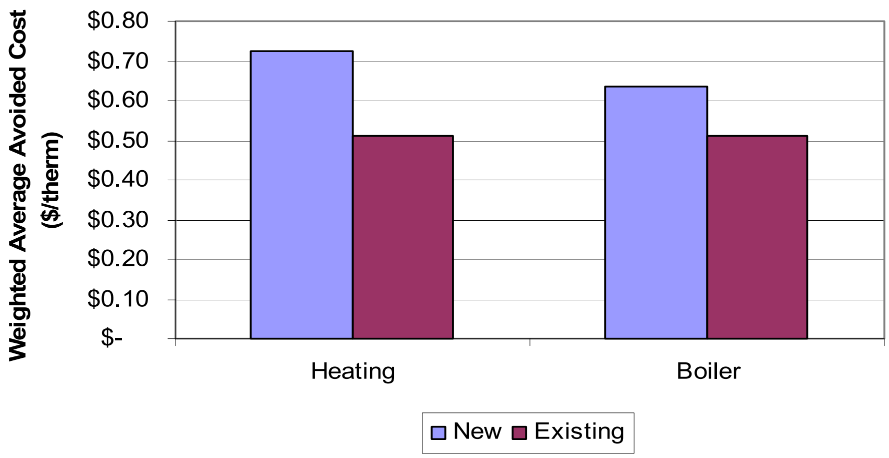


Figure 6. Comparison of Electricity Avoided Costs for Three Example Measures Assuming a 16-Year Measure Life



In Figure 7, we show a comparison of natural gas savings for two measures (heating and boiler efficiency) under the existing and new avoided cost values using a SoCal Gas commercial customer. The vertical axis shows the weighted average savings in $/therm over a 16 year period beginning in 2004. For heating conservation, which is assumed to save energy only during the winter months, the weighted average avoided cost is approximately $0.72/therm with the new avoided costs. This is significantly greater than the $0.51/therm savings this measure would receive with the existing avoided costs. The differential between new and existing avoided cost for boiler improvements is not as large since the measure will save energy all year.

Figure 7. Comparison of Natural Gas Avoided Costs for SoCal Commercial Customer



Conclusion

A comparison of the new and existing electric avoided costs shows that even though average annual electric avoided costs are similar, varying costs by area and time results in more accurate local avoided costs and provides significantly higher benefits for conservation measures implemented during the summer peak period. Similarly, when comparing the new and existing natural gas avoided costs, we see that the new avoided costs are significantly higher in the winter months when commodity prices are higher and T&D is constrained. In both cases, conservation measures that reduce energy consumption during the peak periods (for example, cooling for electric, or heating for gas) receive significantly more value than measures that address off-peak or baseload periods. In the case of the electric avoided costs, efficiency measures that reduce energy in the off-peak periods receive less value under the new avoided costs. Similar updates to avoided costs could be made for other states with their own climates, markets and customers.

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