Thermally activated cooling: a regional approach for estimating building adoption

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Abstract

This paper examines the economic potential for thermally-activated cooling (TAC) technologies as a component of distributed energy resource (DER) systems in California. A geographic information system (GIS) is used to assess the regional variation of TAC potential and to visualize the geographic pattern of potential adoption. The economic potential and feasibility of DER systems in general, and especially TAC, is highly dependent on regional factors such as retail electricity rates, building cooling loads, and building heating loads. Each of these factors varies with location, and their geographic overlap at different sites is an important determinant in a market assessment of DER and TAC. This analysis uses system payback period as the metric to show the regional variation of TAC potential in California office buildings. The DER system payback with and without TAC is calculated for different regions in California using localized values of retail electricity rates and the weather-dependent variation in building cooling and heating loads. This GIS-based method has numerous applications in building efficiency studies where geographically dependent variables, such as space cooling and heating energy use, play an important role.

Introduction

U.S. energy demand for space cooling makes a significant contribution to total commercial building energy consumption. In 1995, total annual end-use energy demand for cooling in the commercial sector was 0.37 EJ (350 trillion Btu), or 6.6 percent of total commercial energy demand.[1] Total commercial space cooling demand is forecasted to grow to 0.51 EJ by the year 2020, which amounts to an annual growth rate of 1 percent.[2] Almost all of this cooling energy is provided by electricity: 97 percent of U.S. commercial buildings with cooling equipment use electricity as a primary fuel for cooling, compared with 4 percent that use natural gas, and 1 percent that use district chilled water.[3] Space cooling is the second-largest commercial end-use for electricity after lighting, and accounts for 13 percent of annual commercial electricity use in the U.S.[4] (EIA, 1995 and 1999).

Space cooling energy demand varies seasonally, and contributes disproportionately to summer electricity demand peaks in hot regions. In California, commercial cooling accounts for 5 percent of total statewide electricity consump-

1. All information presented on cooling use in the U.S. buildings sector is taken from the Commercial Building Energy Consumption Survey (CBECS), published every 4 years by the U.S. Energy Information Administration (EIA). Final survey data are available from the 1995 and 1999 surveys, although detailed end-use data were not available for 1999 at the time of this writing.
2. National Energy Modeling System 2004 Commercial Floorspace and End-Use Consumption input file.
3. A single building may use more than one energy source for cooling.
4. Here, cooling refers to the conditioning of air for human comfort, and does not include fans or refrigeration.

tion, but is responsible for 14 percent of the statewide peak load. In California's commercial sector only, which has the largest electricity consumption and highest growth rate of any sector in the state, cooling is 15 percent of the total electricity consumption but accounts for *38 percent* of the peak load (Brown, 2003). This disproportionate contribution to system-wide electricity peaks is costly for system owners, since it requires additional investment in electricity generation plants that are only operated during a limited number of peak hours throughout the year. In California, like many regions, a building's peak electricity consumption from space cooling can be a large component of the electricity expenses of large commercial customers. California electricity tariffs for large buildings typically bill demand at time-of-use rates, meaning the cost per unit of electricity is higher during pre-defined peak demand periods of the day and year. Large customers additionally pay demand (or power) charges, which are calculated from the customer's peak kilowatt (kW) load in a billing cycle. In some cases, customers are also charged for the portion of their electricity demand that is coincident with the peak load of the utility's whole system.

This paper explores the potential to increase building efficiency and reduce building peak electricity demands in California using on-site power generation combined with waste-heat-driven absorption chillers. The payback of these systems is calculated for different regions of California, and results show how the system economics can vary with local effects of weather-dependent cooling loads and retail electricity prices.

DISTRIBUTED GENERATION AND THERMALLY-ACTIVATED COOLING SYSTEMS

The term *distributed energy resources* (DER) has multiple definitions, but here the term refers widely to any energy production or management system that is located near the point of end use, on the customer side of the meter. Common types of DER systems are energy conversion technologies that produce electricity on-site, called distributed generation (DG), but the wider definition of DER also includes thermally-activated cooling (TAC) technologies such as absorption chillers and dessicant dehumidification systems, demand response technologies, and energy storage.[5] This analysis looks specifically at DG and TAC systems. A key benefit of DG is the opportunity for combined heat and power (CHP) applications, where generator waste heat is used to meet onsite thermal loads. CHP has traditionally been used in large- to medium-scale applications, including industrial applications where high-grade heat is required for industrial processes, food processing, or urban- or campus-scale district heating. With new developments in small-scale (less than 1 MW) generators such as microturbines, fuel cells, and reciprocating engines, CHP applications in the commercial sector have been growing. There is currently at least 5 GW of installed CHP capacity in the U.S. commercial sector, although no comprehensive database of all installations exists (Onsite Sycom, 2000).

TAC systems use heat to drive an absorption cooling cycle, and the heat source can be either direct fuel (typically natural gas or propane) or waste heat from a CHP system, referred to as an *indirect-fired* system. This study looks only at the later, i.e. indirect-fired absorption chillers integrated with a CHP system. Cooling systems are rated by their coefficient of performance (COP), a unitless measure of the effectiveness of a cooling technology, which is defined as the heat removed by the system (expressed as energy) divided by the energy input to the system (either heat or electricity) over a given period of time. The COP of indirect-fired absorption systems ranges from 0.6 to 1.2, depending on the technology and application. Today's typical electric centrifugal chillers have a COP of about 5. While the COP of heat-driven cooling is low compared to electric cooling systems, there can be a large economic benefit to fuel-switching, especially in California and other regions where cooling is a peak-coincident electricity load. In addition, utilizing generator exhaust as a heat source for TAC can improve the efficiency of the combined DER system. The combination of DG and TAC doubly impacts building electricity demand by simultaneously supplying electricity with on-site power generation and reducing electricity demand through the offset cooling load.

THE IMPORTANCE OF A REGIONAL APPROACH

In the commercial sector, DG with TAC has emerged in niche markets where TAC offers a large economic benefit. The largest benefit is realized in buildings with a high space cooling load, in regions where the electricity tariff structure values peak reduction (either through steep time-of-use rates or large demand charges), or in sectors where factors such as high power reliability requirements encourage self generation. In addition, TAC provides a use for waste heat in buildings with low space and water heating loads (which is common in California's hotter regions), where there would otherwise be few opportunities for CHP efficiency gains. Previous work by Berkeley Lab to model the optimal customer adoption of DER has shown that the two largest drivers for absorption cooling technology adoption are high electricity (and demand) charges and a low customer heat load that alone would not provide a significant CHP efficiency benefit (Bailey, 2003 and Firestone, 2005).

These three important factors that influence the economics of DG with TAC – retail electricity rates, high cooling load, and low heat load – all have significant regional variation across California. Retail electricity rates change between utility service territories, of which there are approximately 50 in California.[6] And ambient temperature, which directly determines building cooling and heating demand, can have significant variation locally, especially in coastal or mountainous regions. Even on the scale of large metropolitan areas, taking average values of electricity rates

5. See Peperman et al for a more detailed discussion of DER technologies and definitions.
6. This number includes investor-owned utilities, municipal utilities, federal and state agencies, irrigation districts, and rural electric cooperatives. However, the vast majority of commercial customers fall within the service territoty of California's three largest utilities. (http://www.energy.ca.gov/electricity/utilities.html).

or temperature can eliminate crucial overlaps that will determine niche markets for TAC.

This study uses a geographic information system (GIS) to determine the geographic correlation of the above key factors for TAC adoption in California. A GIS can integrate multiple data sets and link information anchored to a common geography. GIS can be used for a wide range of geographic analyses and visualization techniques, from finding the overlap of different features (e.g. the number of high-temperature regions that are within a utility service territory), to optimization problems based on geography (e.g. what location provides the best market for a DG system based on multiple regional variables). This analysis was conducted using the ArcGIS 9.0 software package from the Environmental Systems Research Institute (ESRI).

Approach and Methodology

This study looks specifically at indirect-fired absorption cooling systems used in conjunction with DG. A *whole-system* approach is used to determine how the installation of an absorption chiller changes the economics, environmental benefits, and market potential of the DER system as a whole. An isolated economic analysis of indirect (waste heat) fired absorption chillers ignores the fact that the value of the fuel (the generator waste heat) is driven by the economics of the prime mover. In general, fuel prices, prime mover turnkey cost and efficiency, and electricity prices will be the primary determinants of system economics.

The example presented in this paper takes the prime mover to be a natural-gas reciprocating engine, and calculates system economics for large California commercial office buildings. There are several reasons why this example was chosen:

- California is a large potential market for DER systems due to the market size, high retail electricity prices, and recent concerns within the state about reliability and customer exposure to price spikes.
- California's electricity requirements are driven in large measure by cooling requirements because of the high saturation of air conditioning in new buildings and the high rate of population growth away from the moderate coast. (California's cooling requirements are discussed in the introductory section above.).
- There is significant climate variation in California, which produces a wide range of building space conditioning needs. The state includes desert regions that record some of the highest temperatures in the U.S., cool mountain areas, and densely-populated coastal regions with a Mediterranean climate. While there is considerable climate variation within the state, it is moderate in many regions (especially the densely-populated areas), producing few heat loads for CHP.
- Office buildings hold promise as a large emerging market for CHP systems (Onsite Sycom, 2000; LaCommare, 2005).The market potential for CHP (including TAC) in U.S. office buildings has been estimated as 10 GW, the highest of any commercial building type (LeMar, 2002).
- Large commercial buildings (with peak loads over 100-200 kW) are likely to be on time-of-use tariffs with demand charges, and therefore can benefit significantly from peak demand reductions.
- A large share of office buildings have space cooling equipment. Approximately 97 percent of all U.S. office buildings have cooling systems, while the average across all commercial buildings is 76 percent (EIA, 1999).
- Previous studies by Berkeley Lab show that reciprocating engines are often the least-cost DG technology at many commercial sites, not including permitting or site-specific installation requirements. (Bailey, 2003 and 2004; Firestone, 2005).

PROBLEM SCOPE

This study does not broadly address the economic potential of DER systems, but instead focuses on the impact of TAC as one component of a DER system. This study identifies regions in California where an additional investment in a TAC system gives an economic advantage over a DER system where waste heat is used only for space and water heating.

On an energy unit basis, the quantity of primary fuel offset by one unit of generator waste heat will be different if the waste heat is used to meet a heating load or a cooling load, and the total offset energy will depend on the efficiency of the absorption chiller, and the relative efficiency of the alternative system used to meet a building's heating and cooling loads (assumed in this analysis to be a natural gas boiler and a conventional centrifugal chiller). Today's single-effect absorption chillers have a COP of up to 0.75 under the most favourable conditions, though the COP for smaller systems under average operating conditions is about 0.6. High-end centrifugal chillers typically have a COP of about 5. The efficiency of a traditional natural gas boiler is assumed to be 85 percent in this study, though efficiencies may be 95 percent or higher for condensing equipment. Figure 1 traces the energy conversion of a unit of generator waste heat used to serve either a cooling load or a heating load. The figure shows the relative amounts of "traditional" fuels (i.e. electricity for cooling and natural gas for heating) that would be used to serve the same loads. This simplified example shows that, primarily due to the high efficiency of a traditional electric centrifugal chiller, one unit of waste heat is the equivalent of 0.94 units of natural gas for a heating load, or 0.1 units of electricity for a cooling load. Therefore, in this example, generator waste heat can offset approximately 9 times the energy of natural gas for heating than the energy of electricity for cooling.[7]

From an economic perspective, the relative retail cost of electricity would have to be 9 times as much as the cost of natural gas to make indirect-fired cooling more economically attractive than heating, if only one of the two options was available.[8] When this analysis is expanded to include a

7. This ratio does not determine the relative total (life-cycle) efficiency of each process, since it does not account for the efficiency of electricity production or transport energy losses.

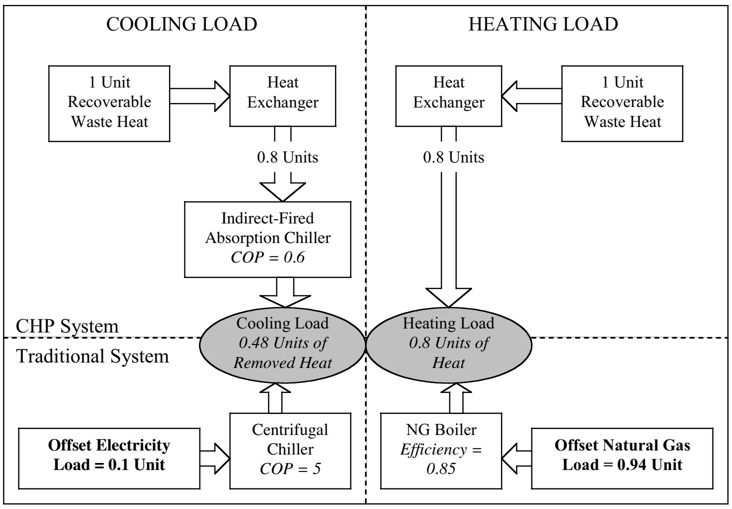


Figure 1. *The Relative Traditional Fuel Equivalent of a Single Unit of Waste Heat Used to Offset an Electric Cooling Load (Left) or a Natural Gas Heating Load (Right).*

building's whole energy system, additional factors contribute to the relative economics of using generator waste heat for cooling or heating. As discussed above, two important factors are: whether the heating load is high enough to make efficient use of all available waste heat and whether the cooling load is large enough to support the incremental investment in an absorption chiller. In this study, a GIS is used to define regions in California that have a unique overlap of:

- utility service territory to determine retail electricity prices,
- average cooling degree days (CDD) to determine building cooling load,
- and average heating degree days (HDD) to determine building heating load.

A cash flow analysis is conducted for each unique combination of these three input variables.

CASH FLOW ANALYSIS

The economics of absorption cooling systems were analyzed using a spreadsheet cash flow model developed by Berkeley Lab. The model calculates the payback of an investment in a DG system, both with and without an absorption chiller. All system capital costs are paid for up-front in year 1. The costs and revenue of subsequent years are calculated in nominal dollars and are determined from 1) fuel costs, 2) operation and maintenance (O&M) costs, 3) savings from the avoided purchase of retail electricity, 4) CHP savings from the offset heat load and/or cooling load, and 5) any increase or decrease in business income tax payments from a change in revenue stream, accounting for the tax deductability of equipment depreciation. The payback is defined as the first year in the cash flow where the cumulative net customer revenue stream is positive.

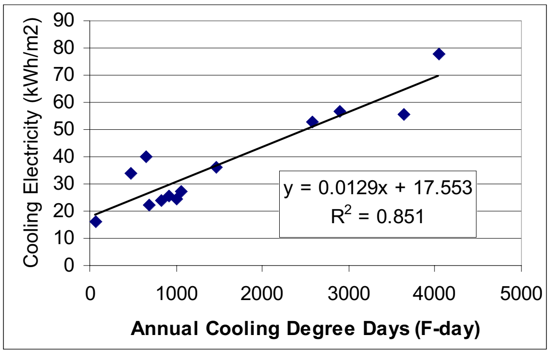
For the heat-only analysis, all available generator waste heat is used to offset building space and hot water loads. It is assumed that the traditional technology is a natural gas boiler with an efficiency of 85 percent. If building heat loads can be completely met, any remaining waste heat is not utilized. When TAC is included in the CHP system, all waste heat is first used to meet the building space cooling loads, and any remainder is used to meet building heating loads. It is assumed that the customer pays incremental capital and O&M costs over investment in a traditional electric cooling system.[9] A feedback effect occurs when the building cooling load is reduced, since primary electricity consumption and generator output will subsequently decrease, which then reduces the amount of generator waste heat available for CHP applications (compared to the waste heat available in the heat-only case). All offset cooling electricity is assumed to be valued at the marginal electricity rate (discussed in more detail below). Additionally, the average electricity rate is reduced to account for the weight of the marginal electricity offset. In both cases, the generator performs *load-following* operation, meaning the generator energy output at any given moment matches the building energy demand.[10]

An important consideration not addressed in this analysis is the seasonal non-coincidence of heating and cooling loads, i.e. cooling and heating loads will generally not be competing for waste heat over the same period of time. This analysis looks at annual averages and therefore does not account for the temporal availability of heat sinks.

The following are key cost input assumptions to the payback analysis:

- The prime mover is a 300 kW natural gas fired reciprocating engine with an installed cost of US$1,160/kW, electrical efficiency of 31 percent, heat recovery efficiency of 66.7 percent, and a variable O&M cost of US$0.013/kWh (NREL, 2003).
- A single-effect absorption chiller is analysed with a COP of 0.6 and an installed cost of US$117/kW of cooling. The alternative system is assumed to be a centrifugal chiller with an installed cost of US$163/kW of cooling. Both systems have an annual O&M cost of US$8/kW of cooling. (LeMar, 2002) The installed base of electric chillers, used to convert building cooling electricity loads to a quantity of heat removal, is assumed to have an average COP of 5.0.[11]
- Natural gas costs US$7.60/GJ, the average commercial rate in California for 2003.[12]
- Electricity prices, gas prices, and O&M costs are inflated using the 2004 Annual Energy Outlook GDP Chain-Type Price Index.

8. In 2003, the average commercial electricity cost in California was US$0.129/kWh, and the average commercial natural gas cost was US$7.60/GJ (US$0.027/kWh).
9. The available alternative system is assumed to be an electric centrifugal chiller. As an average across the existing building stock, the replaced system will be halfway depreciated, and the incremental cost over this traditional system is calculated as the cost above 1/2 the installed cost of the traditional system.
10. The assumption that a generator will perform load-following operation in commercial buildings has been validated by previous Berkeley Lab studies, which show that the least-cost operation in many instances is to buy a large DG system that can meet building peak loads (Bailey, 2003 and 2004; Firestone, 2005).
11. National Energy Modeling System 2004 Commercial Technology Input File (ketch.wk1).
12. Energy Information Administration (http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SCA_a.htm).



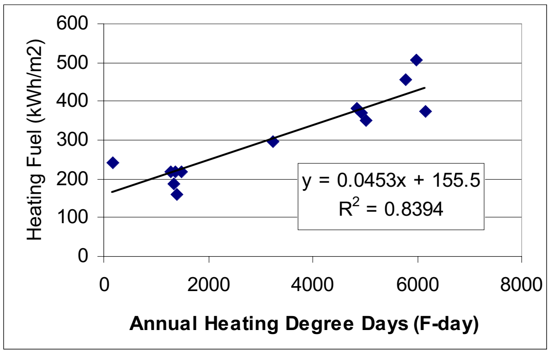


Figure 2. *Correlation of Cooling Degree Days (Left) and Heating Degree Days (Right) With Building Fuel Use.*

- The customer federal and California state combined tax rate is 35 percent.

ADDITIONAL INPUT ASSUMPTIONS

Building Load Inputs

This analysis focuses on a large (5 000 m²) office building with 12-hour operation. Annual energy consumption for the building is derived from a Berkeley Lab study on prototypical commercial buildings in the U.S. by Huang et al. This study simulated building loads for several commercial building types in 13 different climate regions of the U.S. The resulting building end-use loads for a 12-hour office were used to relate cooling and heating load with CDD and HDD, respectively. The annual non-cooling building electricity use (143 kWh/m²) is assumed to be the same across all California climate regions for this example. The total non-cooling electricity load was taken as the average of the three California regions included in the Berkeley Lab study: San Diego, Los Angeles, and San Francisco. Figure 2 shows the correlation between CDD and cooling electricity use and HDD and heating fuel use for a 12-hour office building in the 13 regions examined by Huang et al. The figure also displays the linear fit for the data.

Data on CDD and HDD variation within California were taken from the U.S. National Climatic Data Center, a data archive centre within the U.S. Department of Commerce. The CDD and HDD values (published as Fahrenheit-degree-days) are calculated from a base of 65°F (18°C) over a 30 year average.[13] Figure 3 shows the large variation of average CDD and HDD within California. The eastern mountain areas and northern coastal areas have fewer than 1 000 CDD annually, while regions of California's central valley and populous southern California can have large cooling requirements. The hottest part of the state (more than 3 500 CDD annually) is the eastern desert region that borders Arizona, which has a low population but is one of the fastest growing regions in California. A side-by-side comparison shows fairly consistent correlation between CDD and HDD for most of the state, i.e. the larger the number of CDD, the smaller the number of HDD, although the mild climate of the northern coastal regions results in low requirements for both cooling and heating throughout the year.

Energy Price Inputs

Average commercial electricity prices were derived from the EIA annual data for electric utilities for 2002, the last year for which finalized values were available at the time of this analysis (EIA, 2002). Average commercial rates were calculated by dividing total annual reported revenue by total annual sales.

Cooling electricity saved at peak usage times has a higher value than the average electricity rate, since 1) the peak electricity demand will often push customers into a higher tier of consumption where electricity rates increase, 2) cooling loads occur during peak time-of-use hours where the energy charge is highest, and 3) an increase in peak building load will increase the demand charge. The value of the final kWh of cooling demand in a billing cycle, or the marginal cooling electricity rate, is generally higher than the average electricity rate, especially for large commercial customers. The marginal value of a reduction in electricity demand for cooling is calculated as the total change in a customer's electricity bill divided by the total electricity reduction in kWh. Marginal electricity prices are notoriously difficult to quantify due to the inconsistent structure of electricity tariffs across utilities, but previous work by Coughlin et al at Berkeley Lab has made inroads to this task. Berkeley Lab has collected electricity tariff information for select utilities in the U.S. and has constructed a web-based marginal price calculator.[14] Marginal electricity rates for large commercial customers are included for 7 of the largest utilities in California. Figure 4 below shows the average and marginal electricity prices used in this analysis. Note that the prices shown for the two rates are classified by different scales.

Results

The cash flow analysis for this DG and TAC system was conducted for the following cases:

- Case 1: The installed costs and efficiency values for absorption chillers are today's average values, as described

13. The sample period covers the years 1961 – 1990.
14. See http://tariffs.lbl.gov.

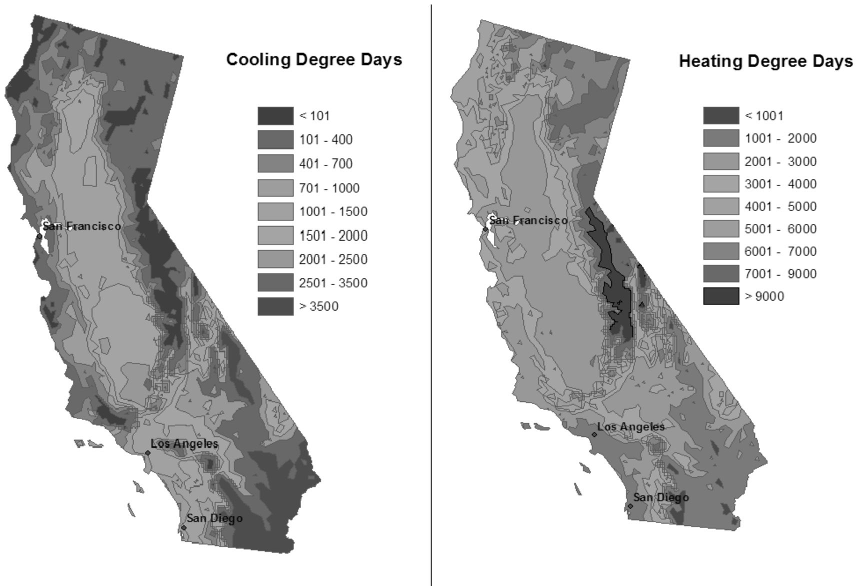


Figure 3. *California Cooling Degree Days and Heating Degree Days (30-Year Average, Base 65˚F).*

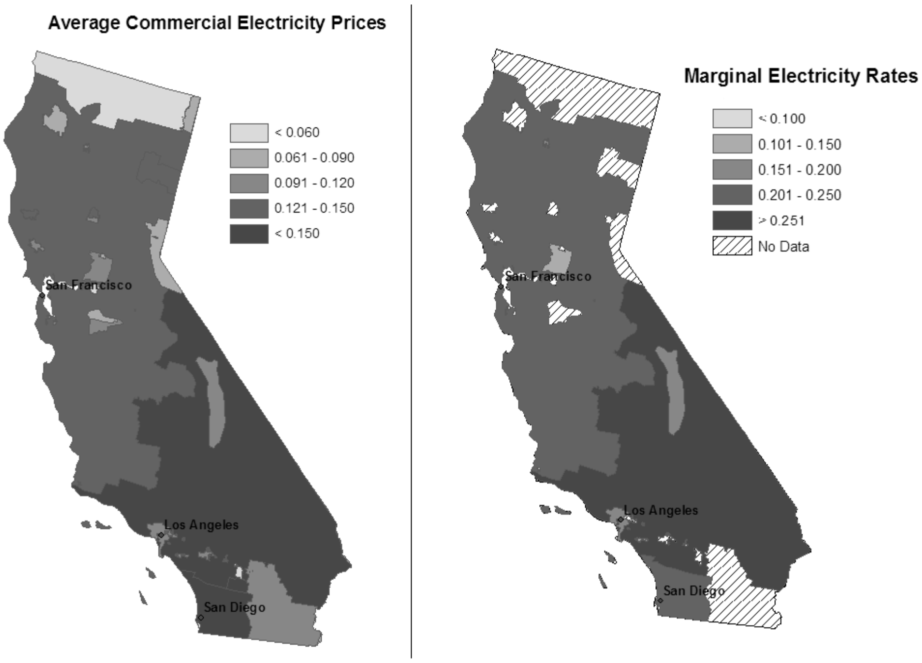


Figure 4. *Average and Marginal Electricity Rates for Select California Utilities (in US$2002). Note that Prices are Shown on Different Scales.*

above in the input assumptions (a COP of 0.6 and an installed cost of US$117/kW of cooling).

- Case 2: The COP of the absorption chiller is increased to 0.7 and it is assumed that the full cost of a traditional cooling system is offset, resulting in no incremental cost for the absorption chiller. (This would be the case if a TAC system was installed when the traditional system had fully depreciated.)
- Case 3: The prime mover installed capacity is reduced from 300 kW to 200 kW as a result of building peak load reductions. For this case the installed cost of the natural gas engine is increased to $1 350/kW.[15]

Figure 5 presents payback results assuming today's installed costs and efficiencies for absorption chillers (Case 1). The DER system payback when TAC is not installed (the heat-only scenario) is shown on the left, and the payback with TAC is shown on the right. Without TAC, this DG system has a payback in the 4-6 year range in the majority of California. The exceptions are in smaller municipal utility service areas where average retail electricity rates are lower than those of California's larger utilities. The integration of TAC

15. NREL data were not available for a 200 kW system, so installed cost data for two 100 kW systems is assumed (NREL, 2003).

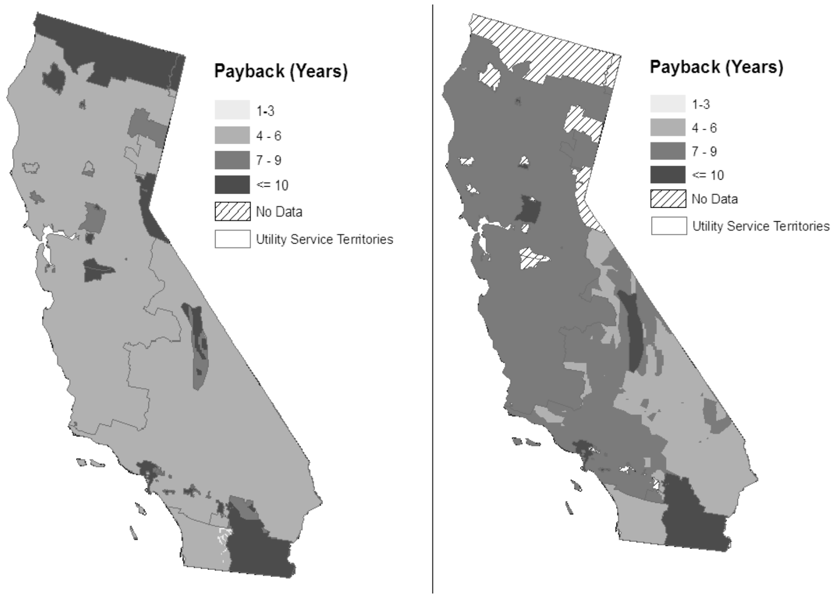


Figure 5. *Case 1 Payback Results Without a TAC System (Left) and With a TAC System (Right).*

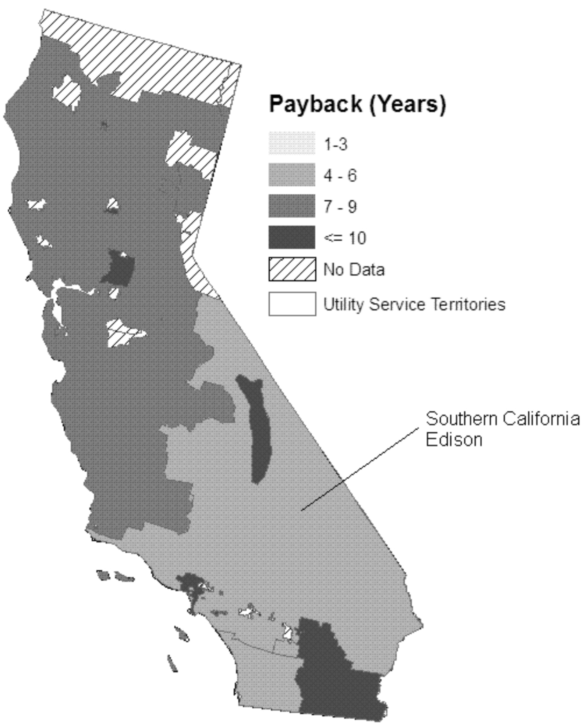


Figure 6. *Case 2 Payback Results With a TAC System.*

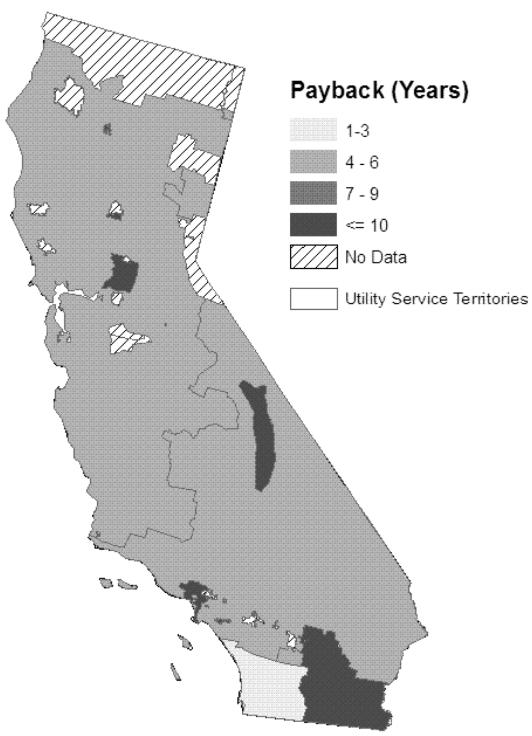


Figure 7. *Case 3 Payback Results With a TAC System.*

with the DER system increases the overall system payback in many regions. The exceptions are the hotter regions in the southeast part of the state where building demand for space cooling is high. However, the overall pattern of DER economics is dominated by retail electricity rate changes between utility service territories, and less so by climate variation.

Figure 6 shows results for the DER system with TAC for Case 2, where the COP of the absorption chiller is increased from 0.6 to 0.7 and there is no incremental installed cost for the TAC system. These more aggressive system assumptions lower the payback period in the large portion of the state that falls in Southern California Edison service territory, where average and marginal electricity rates are high. However, the overall economics of the DER system do not change noticeably in the rest of the state with these improvements to the TAC system. In addition, the payback period is higher than the payback of a system without TAC.

Figure 7 shows payback results for the DER system with TAC when the installed capacity of the prime mover is reduced from 300 kW to 200 kW (Case 3). For this scenario, the payback period is reduced to 4-6 years in the majority of

California, with a 1-3 year payback in the San Diego area and a higher payback period in the smaller utility service territories. Results show that lowering the installed capacity and the up-front capital cost of the prime mover can significantly reduce the payback period, and can lower the system payback below a DER system without TAC in certain regions of California. This shows that a key benefit of reducing a building's peak demand through a combined DG and TAC system is the ability to lower the capacity requirement for an on-site DG system, even with the economy-of-scale advantages of larger systems. It is important to note that a prime mover capacity reduction will have a larger impact on a payback analysis than on other economic metrics, since the total up-front cost is a key variable in a payback analysis.

Conclusion

Space cooling in U.S. commercial buildings is the second largest end-use for electricity, and makes up 6.6 percent of total commercial energy demand. In addition, cooling demand contributes disproportionately to system electricity peaks. In commercial buildings in California, space cooling accounts for 15 percent of total electricity consumption but contributes 38 percent of the peak load. Efficiency measures that reduce peak cooling electricity consumption are especially valuable in large commercial buildings, where customers are often billed at time-of-use rates and additionally pay demand charges based on their peak load in a billing cycle.

TAC systems used in conjunction with DG offer one potential way to lower building peak electricity use from cooling. However, the economic attractiveness of TAC as one component of a larger CHP system will depend on the availability and economic value of offset building heating loads. The relative economic potential of TAC compared to a CHP system for heat-only loads depends on the site-specific values for retail marginal electricity rates, building cooling load, and building heating load. In California, geographic data show that there is large variation among these three factors throughout the state. At today's average installed costs and COP of TAC systems, most regions in the state have a lower payback period (on the order of 4-6 years) when the DG waste heat is used to meet building space and water heating loads only. The payback period for DG and TAC systems is reduced when TAC performance is improved and the incremental installed cost is lowered, but TAC does not become competitive with a heat-only CHP system. This is primarily due to the relative cost of electricity and natural gas in California, which places a high value on an offset natural gas heat load. The payback period of DG with TAC is lowest when the offset cooling load allows for a lower installed capacity of the DG prime mover. In this scenario TAC is competitive with CHP for heat-only loads in the majority of California, and TAC has a lower payback period than a heat-only CHP system in the San Diego area. This analysis finds that the largest impact on DG and TAC economics comes from variation in retail electricity rates with utility service territory, more so than variation in building heating and cooling loads.

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Glossary

CBECS	Commercial Buildings Energy Consumption Survey
CDD	cooling degree days (Fahrenheit)
CHP	combined heat and power
COP	coefficient of performance
DER	distributed energy resources
DG	distributed generation
EIA	U.S. Energy Information Administration
ESRI	Environmental Systems Research Institute
GIS	geographic information system
HDD	heating degree days (Fahrenheit)
O&M	operation and maintenance
TAC	thermally-activated cooling

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