AN ENERGY RESOURCE INVESTMENT STRATEGY (ERIS) FOR THE CITY AND COUNTY OF SAN FRANCISCO

FINAL REPORT

ROCKY MOUNTAIN INSTITUTE

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RMI is an independent, nonprofit, applied research center that fosters the efficient and restorative use of natural and human capital. Dr. Joel Swisher directed this project and authored this report. Katherine Wang conducted many portions of the analyses and contributed to the writing of this report. Will Clift conducted the project level analysis and contributed to several sections of the report. Joanie Henderson provided research on efficiency programs and contributed to the report. Craig Collins contributed to the efficiency potential analysis. Thanks also to Dr. Amory Lovins, Kyle Datta, and Odd-Even Bustnes, who contributed analyses and ideas to this project.

EXECUTIVE SUMMARY

The City of San Francisco is at a crossroads with regard to energy policy. It faces decisions about how to replace electricity from two aging, highly polluting power plants at Hunters Point and Potrero Hill. To help clarify the complex and at times conflicting problems, and to prioritize the work and investment needed to begin to solve them, Rocky Mountain Institute (RMI) has worked with the City of San Francisco, through the Public Utilities Commission (SFPUC) and Department of the Environment (SFE), to assemble an Energy Resource Investment Strategy (ERIS) for the City and County of San Francisco.

The ERIS is a set of energy resource portfolios, based on a range of possible future scenarios that combine existing and future energy resources to meet San Francisco's need for adequate and reliable supply of electricity services, while minimizing costs and environmental impacts. In this report, we evaluate several combinations of resource options in detail and analyze their economic and environmental implications for San Francisco. Based on the results of this analysis, we present a set of recommendations for the City's consideration.

In the initial RMI scenario analysis for San Francisco,[1] we explored several very distinct technological pathways, including a large central generation plant that was proposed at the time, and showed that San Francisco had more choices for its energy future than had been widely recognized. In this document, we explore a wider range of energy resource decisions in San Francisco in the short (2006), medium (2013), and long terms (2020). The focus here is on distributed, local solutions that address both supply and demand-side options at a minimum of economic and environmental cost.

There are a variety of energy technologies and resource strategies that can satisfy San Francisco's need for electricity services over the next twenty years. The resource options include central generation, distributed generation, renewable energy, additional transmission of imported power, energy efficiency and load management. A combination of these options provides the most robust strategy to ensure reliable service and allow the closing of the Hunters Point plant and eventually of the Potrero power plant as well.

San Francisco is located at the end of the San Francisco Peninsula, where the only transmission corridors enter via San Mateo and several lines along the Peninsula. This bottleneck limits the amount of power that the City can import from the power market or even from its own resources. While San Francisco can produce clean, inexpensive hydropower at Hetch Hetchy and at wind farms in Alameda County and elsewhere, only transmission capacity and in-City generation contribute to service reliability within the Peninsula transmission constraint.

In the 2005 timeframe, the key resource to allow the Hunters Point plant to be retired is the new City-owned combustion turbines (CTs), which can provide sufficient generation capacity within the Peninsula transmission constraint to maintain supply reliability without the continued

[1] Rocky Mountain Institute, 2002. *An Energy Resource Investment Strategy for the City of San Francisco: Scenario Analysis of Alternative Electric Resource Options*, report to the San Francisco Public Utilities Commission.

operation of Hunters Point. The California Independent System Operator (CAISO) has stipulated that the construction of these CTs is a necessary condition for the Hunters Point retirement.

In the 2006-2013 timeframe, construction of the Jefferson-Martin 230-kV transmission line and the associated 115-kV Martin-Hunters Point line will provide additional insurance of supply reliability and make it possible to eventually retire the Potrero plants. Also, to capture the full benefit of the Jefferson-Martin and other transmission capacity additions, other transmission upgrades will need to be completed first. These upgrades include projects within the City (such as Hunters Point-Potrero), on the Peninsula (such as San Mateo-Martin line 4), and in the greater Bay Area (such as Newark-Ravenswood).

Distribution capacity within the City is another potential resource issue. We anticipated using marginal distribution capacity costs in our economic analysis of resource options. However, according to PG&E the short-to-medium-term, needs for distribution works in San Francisco are modest and unlikely to cause major cost differences between areas in the City. Gas transmission and distribution capacity appears adequate to accommodate the modest projected increases in demand. Thus, distribution capacity and costs were not considered in detail, but we recommend that this question should be revisited in the future to possibly identify where and when targeted DG and DSM could provide cost savings in the distribution grid. At a minimum, new projects such as the redevelopment of the Hunters Point Naval Shipyard site, will demand distribution expansion, the cost of which could be reduced through targeted DG and DSM in such areas.

Distributed (co-) generation (DG) in the private sector needs to become a significant resource in San Francisco during the next ten years. Current technology, based mostly on reciprocating engines, should evolve toward small combustion turbines and eventually fuel cells to improve performance and minimize CO_2 and local emissions. In the longer term, DG must become San Francisco's most important new source of supply-side capacity, in order to allow for the eventual closure of the remaining central fossil-fuel generation plants. We estimate 275-315 MW of DG potential by 2020. This potential, much of it based on fuel cell technology, would need to be fully exploited for the last central generation in the City to be retired. If fuel cells are not cost-effective within this timeframe, central generation will remain necessary, but San Francisco would still achieve most of its goals in terms of emission reductions and environmental equity.

San Francisco will also need to aggressively increase its energy efficiency and peak load management efforts over the entire planning period in order to control peak demand, minimize power imports, and satisfy reliability requirements. PG&E and City-run demand-side management (DSM) programs will be key to ensuring adequate capacity reserves. DSM programs must address both summer and winter peaks, as well as the total energy use, in San Francisco. We estimate that aggressive but reasonable exploitation of cost-effective EE potential can reduce existing loads by about 1% per year and projected load growth by about 30%. This amounts to about 140 MW saved in 2013 and 225 MW in 2020. Also, load management can reduce peak demand in summer by 30 MW and in winter by 10 MW.

While the transmission capacity addition from the Jefferson-Martin line and other transmission projects will be adequate to handle the additional required imports, increased dependence on purchased power could make the City vulnerable to volatile fluctuations in power market prices.

On the other hand, the City must be careful not to develop in-City central generation with so much capacity under a single owner (250 MW plant or greater) that it becomes vulnerable to the market power of a single power merchant.

Renewable sources can play an important role in the City's energy resources in the medium-to-longer term. In-City solar generation can make a small but significant contribution to meeting summer peak demand, due to its coincidence with the solar resource. The amount of useful solar power is limited by the relatively small difference between the City's summer and winter peak loads, as the winter peak occurs at night. A combination of solar and peak load management can reduce peak demand to a similar level in both seasons, making best use of all supply resources.

Utility-scale wind power is unlikely to be developed in large quantity within the City and thus would not contribute to supply capacity within the Peninsula transmission constraint. However, there are excellent wind resources elsewhere in the Bay Area, and new wind farms in these areas could provide energy to the City at relatively low cost, provide a reliable hedge against fuel and power price volatility, and substantially reduce GHG emissions from the City's power supply. A small amount of in-City wind power is expected near the Bay. We estimate that 160 MW of wind power can be developed by 2013, and 250 MW by 2020, mostly outside the City.

Hydropower from the Hetch Hetchy Water and Power system will continue to be an important resource for the City. The water and power supply and delivery infrastructure needs to be refurbished to maintain reliability and increase performance and power output. This resource will become even more valuable when other intermittent renewable resources such as wind are added. The hydropower, being dispatchable, can fill in additional power supply when the intermittent sources are not producing at full capacity. Additionally, renegotiation of the power supply contracts between the San Francisco and the irrigation districts in Modesto and Turlock will help the City gain more control over its supply resources.

Fuel cells are a key component to a longer term (post-2010) strategy to reduce and eventually eliminate central fossil-fuel combustion from the City's power supply mix. To achieve the potential offered by fuel cell technology, the City will first need a robust infrastructure for distributed co-generation as described above, based initially on conventional combustion technologies. The economics of fuel cell technology must also improve. We expect technological development over the next 5-10 years to reduce the costs of fuel cell technology, as well as the related costs of hydrogen conversion. However, we include scenarios where costs remain high.

Regardless of technological developments, the economics of fuel cells and distributed generation in San Francisco can also be improved by collaborating with PG&E and customers to identify and capture additional economic value from reliability support, grid cost savings, and ancillary services. One approach to fuel cell application could be the use of vehicle-to-grid (V2G) generation using fuel cell vehicles to meet on-peak electricity demand. Of the 275-315 MW of DG potential by 2020, we estimate that 120 MW (about 40%) could come from stationary fuel cells, and another 50 MW could come from V2G.

Other renewable energy resource options should continue to be evaluated to determine their potential application as part of a longer term (post-2010) strategy to reduce and eventually eliminate fossil-fuel generation from the City's imported power supply. These technologies include tidal power in San Francisco Bay and pumped storage hydro for peaking capacity. In particular, tidal current power technology is worth monitoring, as it could have good potential in San Francisco Bay as the technology matures, provided that siting challenges can be resolved.

Because resource planning considers the future, it is subject to uncertainty, which we address using a scenario approach. We built a set of possible future scenarios that express uncertainties, such as technology costs and economic growth, which influence energy resource decisions. In each scenario, we design a recommended ERIS portfolio and then analyze its implications in terms of total cost, emissions, reliability, etc. Thus, the *scenario results represent different states of the world, in which we recommend an ERIS portfolio to achieve the City's goals in each case.*

In our scenario analysis of the energy resource portfolios, we treat energy efficiency and peak load management as an energy resource comparable to new electricity supplies. Therefore, we present the results as combinations of supply and demand-side resources that meet the total projected demand for electricity services in each scenario. We address both total consumption and peak demand, ensuring that adequate transmission capacity for power imports is available and that reserve margins are sufficient to satisfy first-contingency planning conditions.[2]

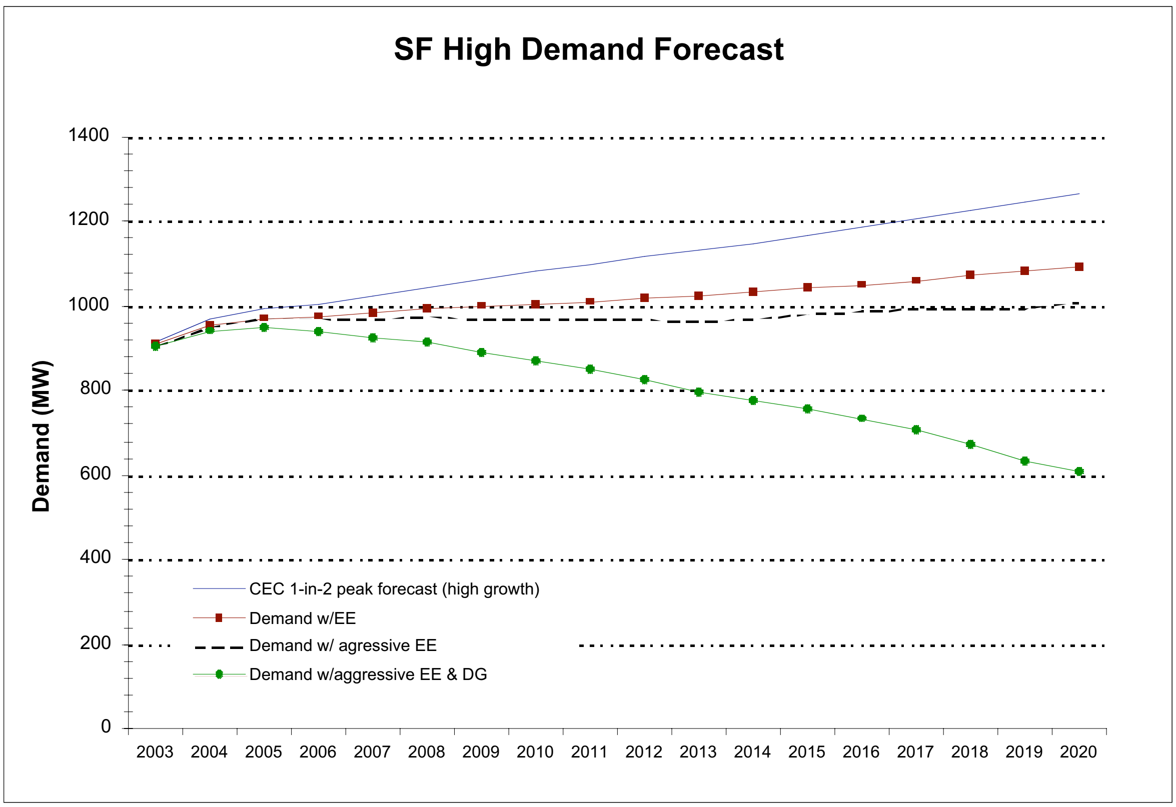

Figure 1. Net demand in San Francisco assuming high growth, selected portfolios

[2] This criterion requires that peak loads can be met with the largest generating unit out of service. The San Francisco electricity system is designed to meet *double first-contingency conditions*, i.e., the simultaneous loss of both the largest generation unit and the largest transmission component.

The impact of demand-side management (DSM) and distributed generation (DG) on the demand for central generation is shown in Figure 1 for the low baseline growth scenarios and in Figure 2 for the high baseline growth scenarios. DSM can limit future net demand growth to about zero, in the high-growth, high-efficiency scenario or in the low-growth, moderate-efficiency scenario. Remaining demand is met by a combination of DG and central generation, including imports. DG reduces the net demand for central generation to about half of the original demand forecast in the later years of each of the high efficiency, high DG scenarios. In-City generation is supplied by DG and co-generation, and a growing share of this in-City DG is provided by fuel cells.

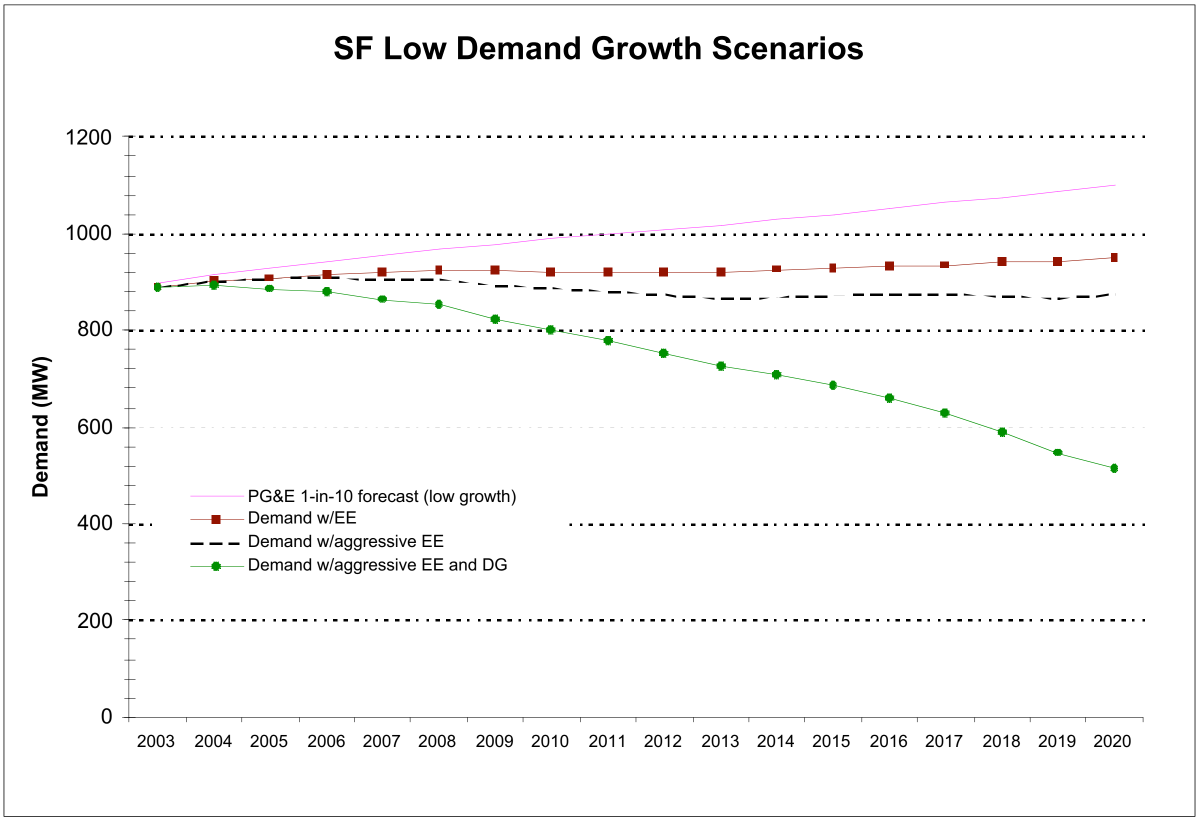

Figure 2. Net demand in San Francisco assuming low growth, selected portfolios

A sample of the detailed scenario results is shown below for two scenarios: the high-demand, moderate efficiency, high DG scenario and the low-demand, high efficiency, low DG scenario. The energy demand differences reflect assumed future economic growth rates. The efficiency differences reflect assumed impact of DSM programs. The DG differences reflect assumed fuel cell cost and technology improvement.

The resource portfolio for the high demand scenario, shown in Figure 3, must meet the highest net demand (after efficiency and load management) of any of the scenarios we considered. This scenario assumes that low-cost fuel cells become available in time to contribute to DG resources by 2020. In this scenario, the Hunters Point power plant is retired in 2005; the Potrero plant is retired in 2011 (and the peakers earlier); and the new in-City CTs are retired in 2019. By then, a combination of moderate energy efficiency gains and aggressive DG development, including fuel cells, is sufficient to replace all central fossil fuel-fired generation in the City.

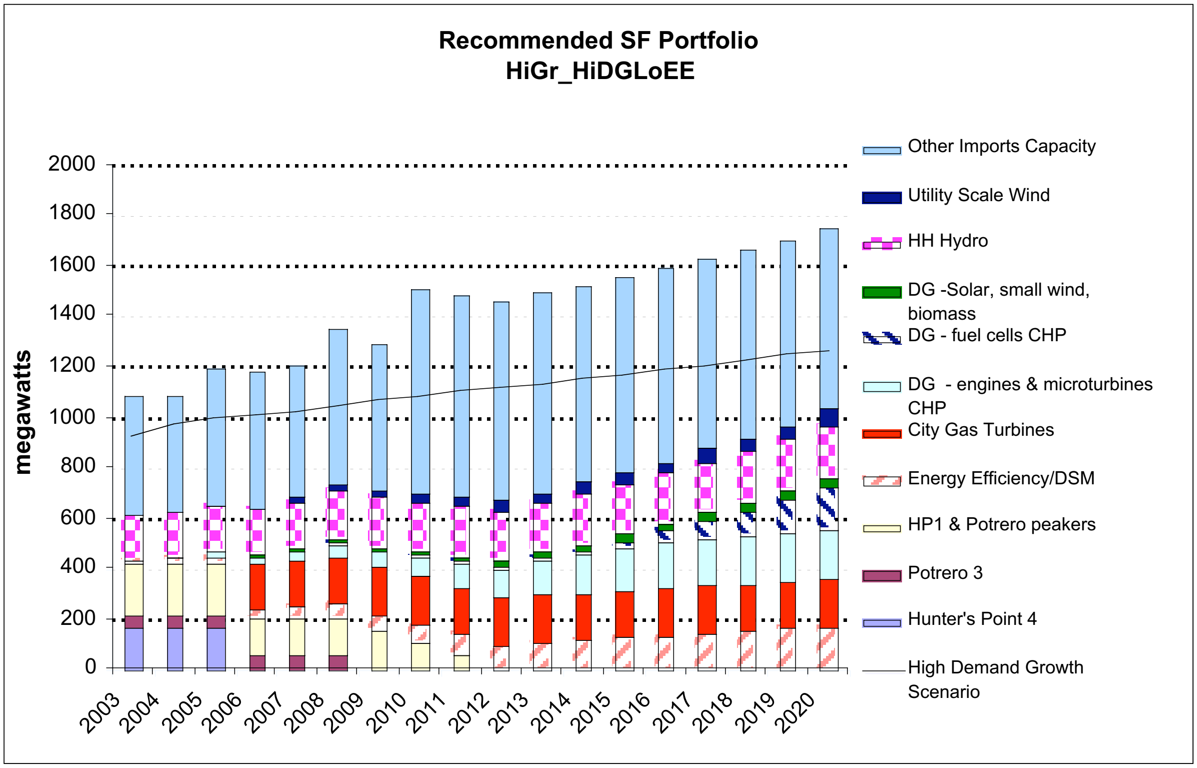

Figure 3. Resource portfolio to meet peak demand: high demand, aggressive DG

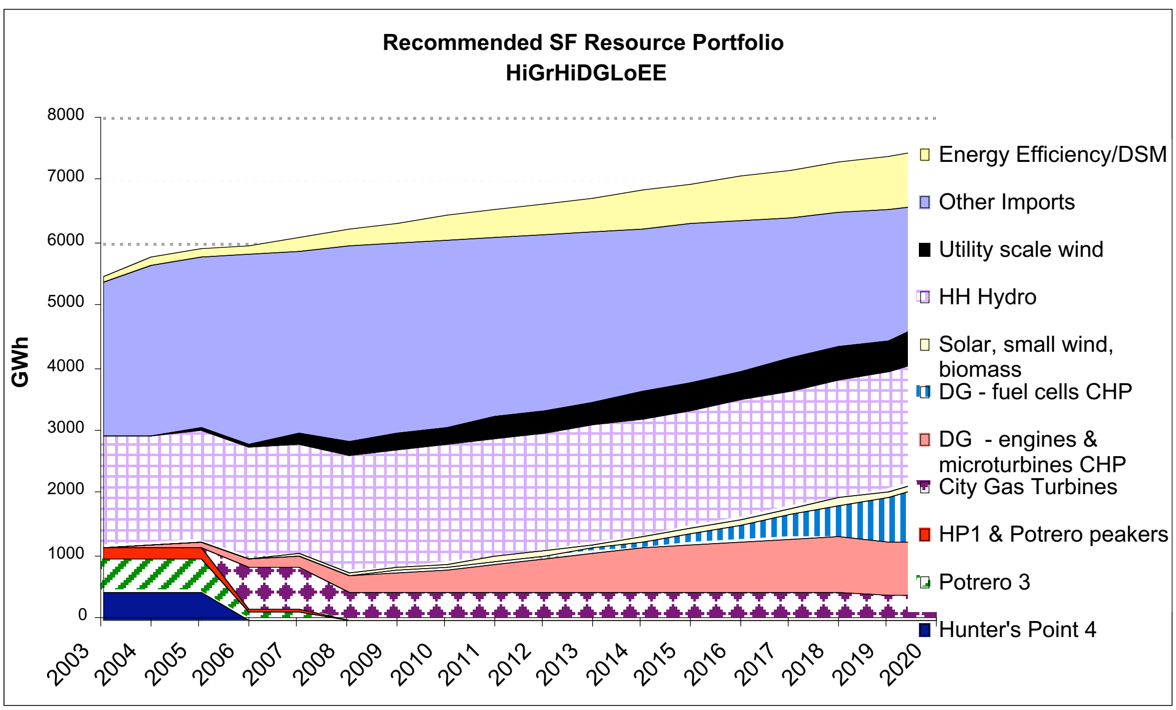

Figure 4. Resources to meet annual energy demand: high demand, aggressive DG

For the same scenario, the results in terms of annual energy use and production are shown in Figure 4. In-City generation is able to meet all net demand without needing to operate the old peakers at Potrero, which are the most polluting generation source in the City. Distributed generation, initially from combustion sources and later from fuel cells, meets an increasing share of the demand, and renewable energy from in-City solar, remote wind farms and Hetch Hetchy hydro upgrades provide significant quantities of clean energy.

The resource portfolio for the low demand scenario is shown in Figure 5. With low baseline demand growth and high impact from efficiency programs, the net demand (after efficiency and load management) is the lowest of any of the scenarios we considered. In this scenario, the Hunters Point power plant is retired in 2005, and the Potrero plant is retired in 2011 (and the peakers earlier). Falling demand from aggressive energy efficiency programs free up enough supply resources to allow retirement of the new in-City CTs in 2020, but this scenario just barely satisfies our minimum in-City generation criterion for system reliability and stability. Thus, we are not confident that all central generation can be retired without the availability of low-cost fuel cells or a similar breakthrough in the cost and performance of renewable energy technology.

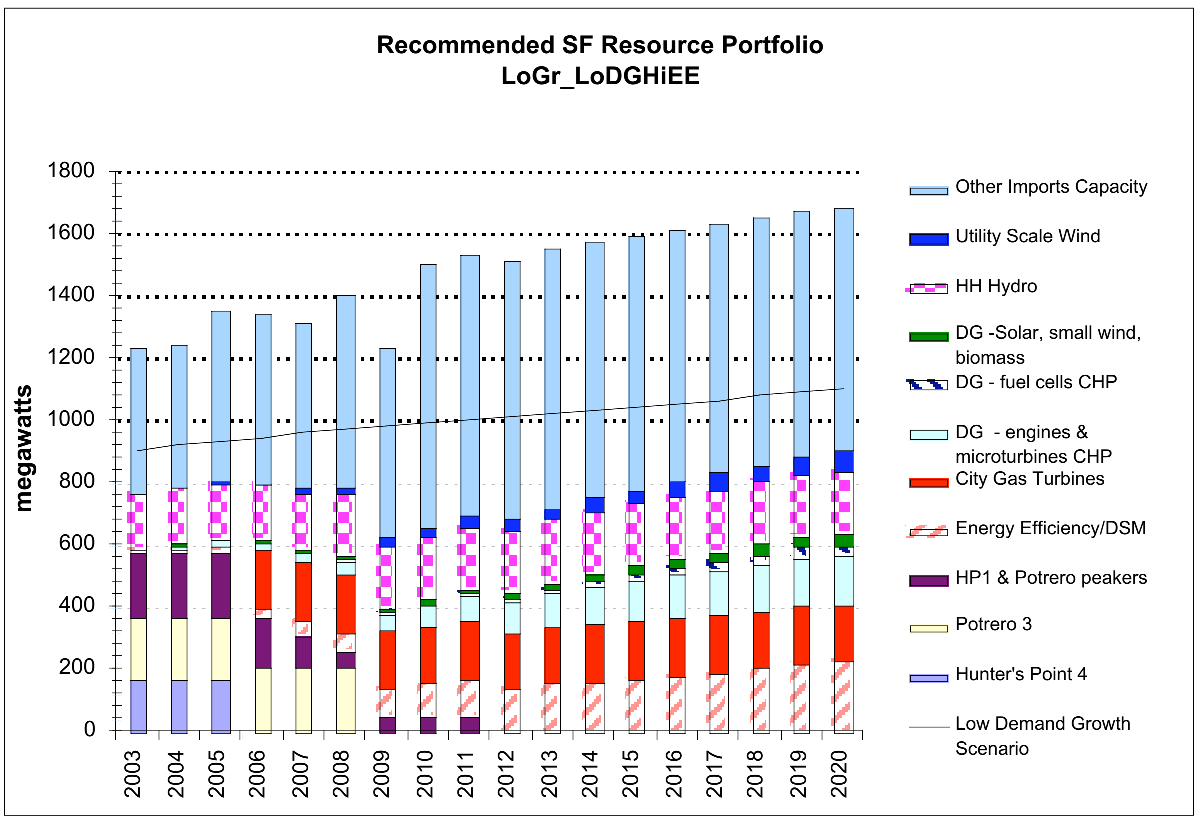

Figure 5. Resource portfolio to meet peak demand: low demand, high efficiency

For this scenario, the results in terms of annual energy use and production are shown in Figure 6. With the reduced net demand level, in-City generation meets all net demand without operation of the old peakers, and Potrero unit 3 rarely runs above its minimum level of output. Distributed generation from combustion sources meets a modest share of demand, and renewable energy from in-City solar, remote wind farms and Hetch Hetchy hydro upgrades provide a similar amount of energy as in the high demand scenario, but meet a larger share of total City demand.

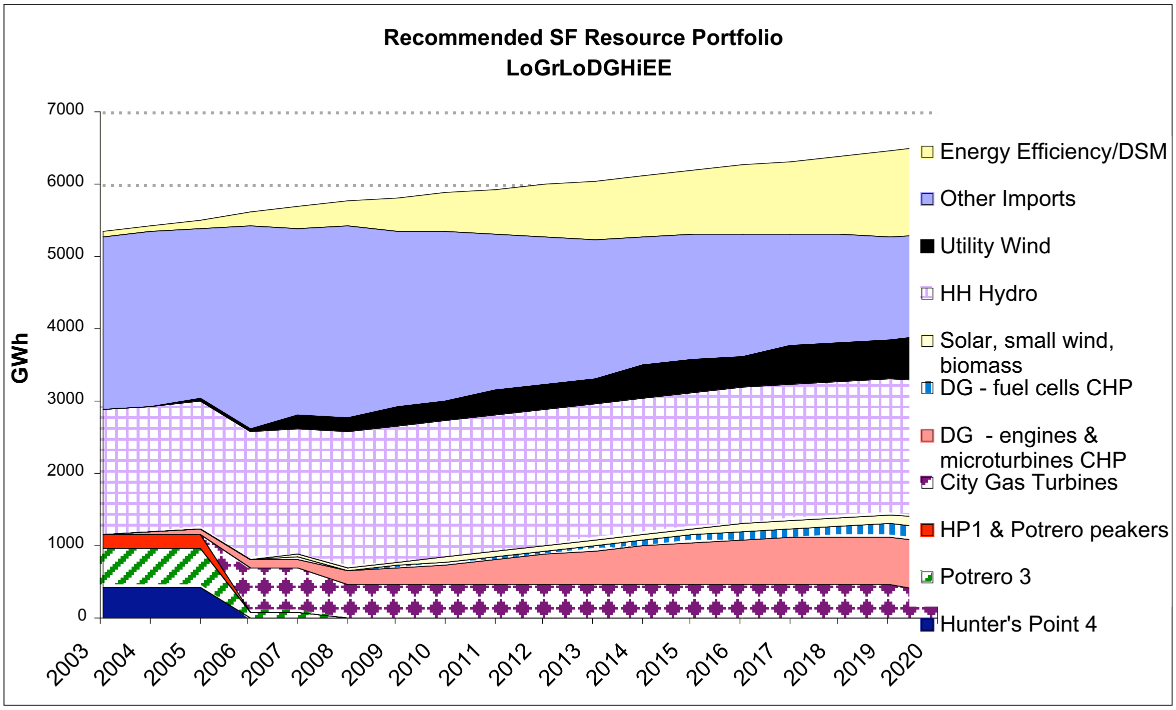

Figure 6. Resources to meet annual energy demand: low demand, high efficiency

These strategies can meet San Francisco's growing demand for electricity services without a significant increase in the average cost per kWh produced or saved. As shown in Figure 7, the total annualized costs (including capital investments and annual operation and fuel costs) per kWh increases slightly from $0.05/kWh in 2003 to between $0.065 and $0.07/kWh in 2020, which approximately tracks the assumed rate of inflation (1.5% per year). To the extent that efficiency programs are funded through utility energy providers such as PG&E or the SFPUC, energy prices may increase somewhat because the costs of producing and saving energy would be recovered from the sale of fewer kWh of electricity (or million Btu of gas). The reason that costs do not increase while utility rates do increase is that customers will need to buy less, albeit somewhat more expensive, energy.

San Francisco will remain susceptible to volatility in natural gas prices, such that a 25% increase in gas prices would also increase the average cost per kWh of electricity by about 10%. The reason for this exposure is that all sources of heating are fueled by gas, and virtually all thermal sources of electricity are gas-fired. Improved energy efficiency and more use of renewable sources, via in-City sources or imports, can only partially relieve this dependence. Our economic analysis captures much of the price risk of natural gas dependence by using the price of long-term gas futures contracts as a proxy for future gas costs. While future prices may be lower than these values at times, this approach explicitly values the price risk entailed in relying on purchased gas, and the corresponding risk reduction provided by fixed-cost renewables.

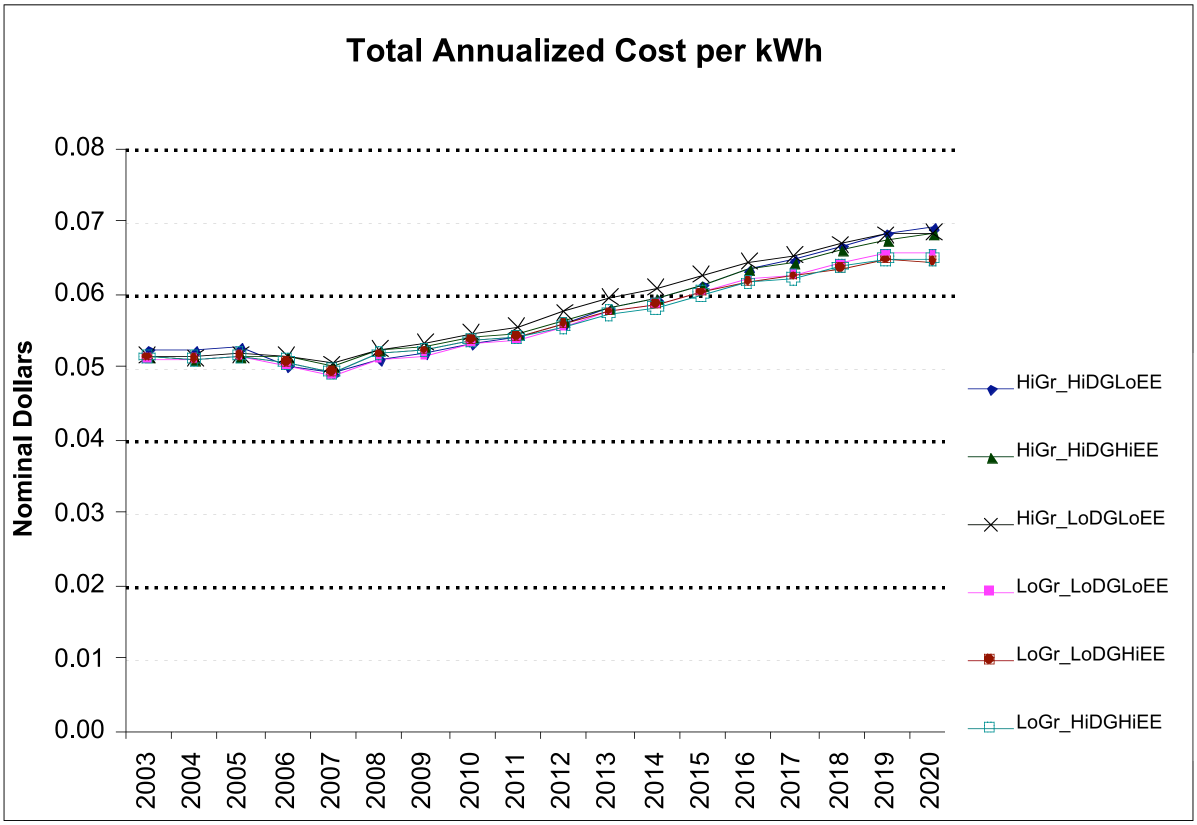

Figure 7. Annualized cost per kWh for San Francisco, 2003-2020

Our principal measure of the adequacy and reliability of the power supply system is to consider the reserve margin, which is the amount that the total in-City generation capacity, together with the transmission import capacity, exceeds the summer peak demand (net of energy efficiency savings). Figure 8 shows the reserve margin based on the transmission capacity. To satisfy the double first contingency criteria (largest transmission and generation units out of service), the reserve margin value shown in Figure 8 must be greater than the capacity of the largest in-City generation unit, which is 207 MW as long as Potrero unit 3 is in operation and 50 MW thereafter.

The replacement of the Hunters Point by the new City peakers and later the closure of the Potrero Hill plant reduce local emissions dramatically. As shown in Figure 9, local NOx emissions are reduced quickly by 80-90% compared to the present situation, and PM_{10} emissions are reduced by 50-70%. As more of the City's power supply is generated from distributed sources within San Francisco, the remaining, much-reduced emissions are distributed much more evenly around City compared to today's concentrated and much higher emissions in the neighborhoods adjacent to Hunters Point and Potrero.

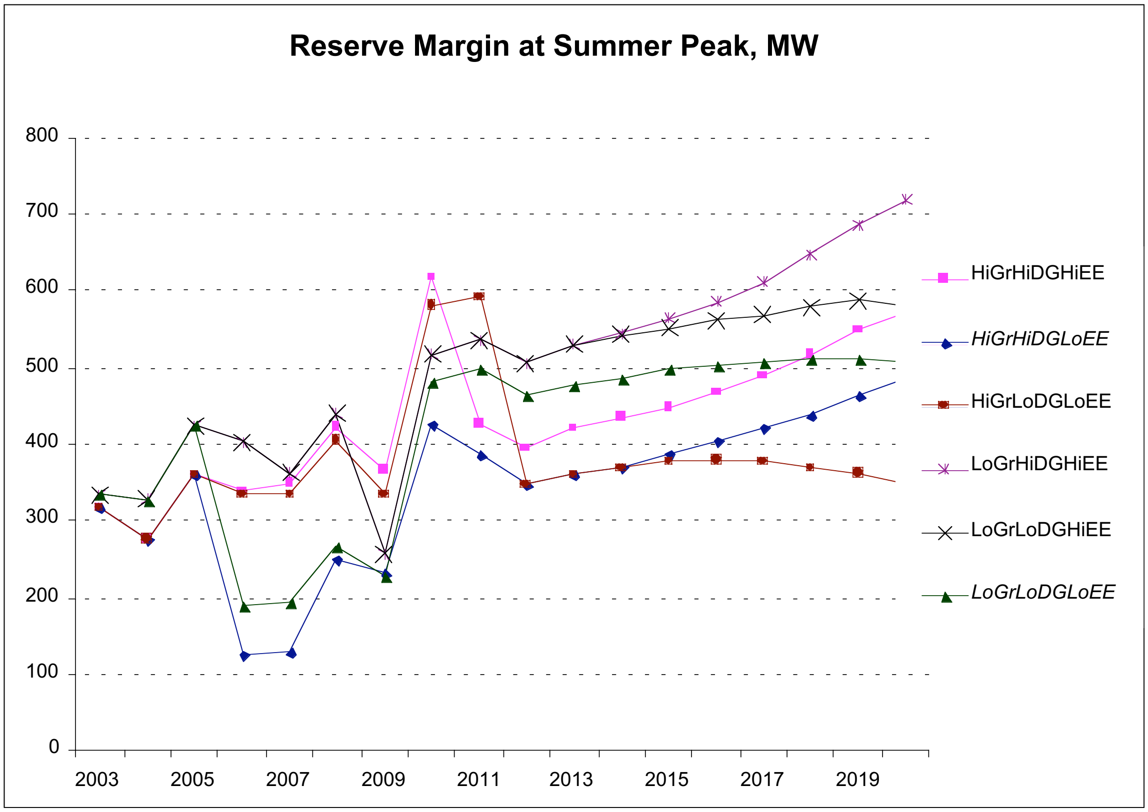

Figure 8. Reserve margin (MW) at summer peak with first transmission contingency

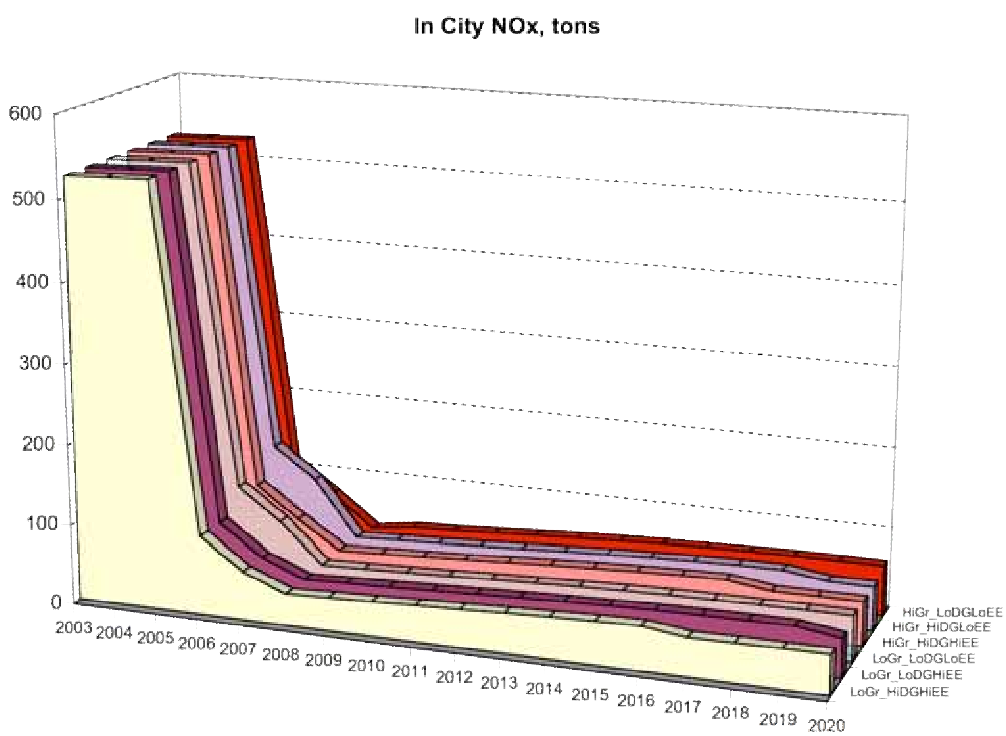

Figure 9. In-City NOx emissions for selected scenarios, 2003-2020

Overall CO_2 emissions, shown in Figure 10 including those caused by the generation of power imported to the City, are reduced significantly, by 20-50% compared to the present situation. The larger emission reduction savings result from lower overall energy use, due to lower baseline demand growth and/or more aggressive energy efficiency improvements. Renewable energy such as wind farms remote from the City also contributes to emission reductions, even in the scenarios where power demand increases over time.

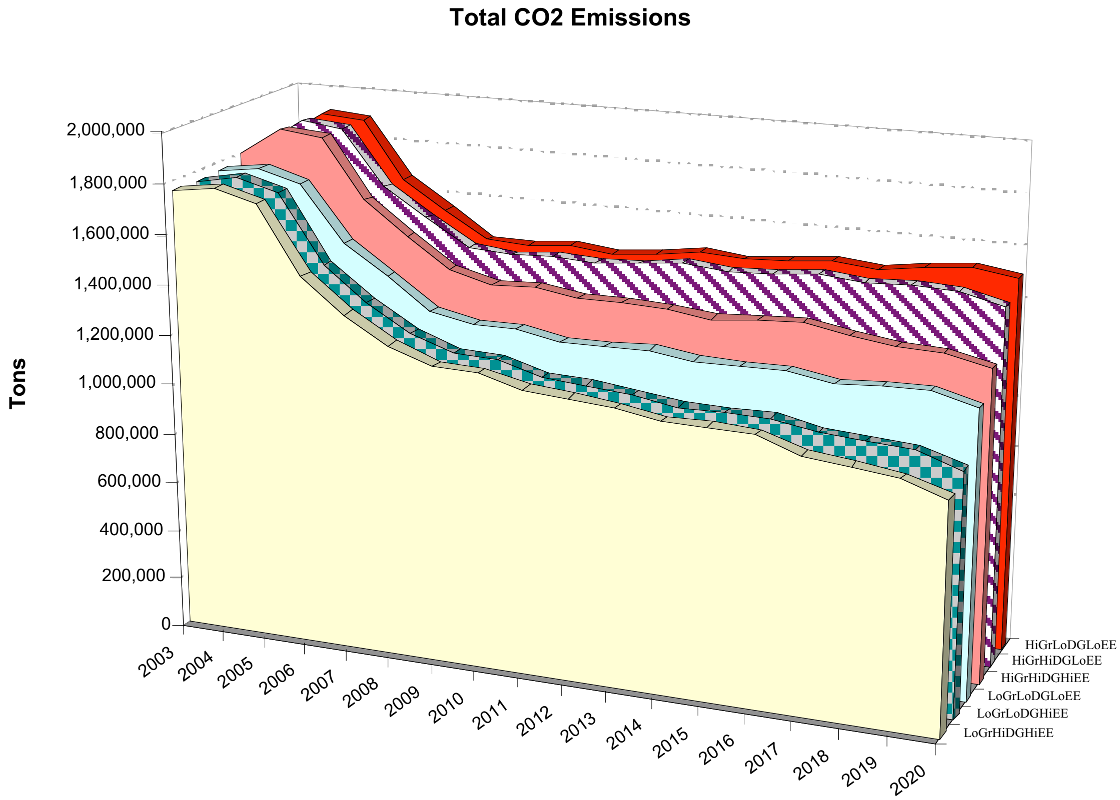

Figure 10. CO_2 emissions for selected scenarios, 2003-2020

Additional emission reductions associated with the ERIS scenarios result from natural gas savings in buildings that undergo energy efficiency upgrades. A small decrease in gasoline use associated with incentives to switch to fuel cell vehicles and produce V2G generation causes further emission reductions.

A strategy that emphasizes energy efficiency and distributed generation can provide several other difficult-to-quantify benefits, such as local economic development and net job creation. A simple analysis of the job impacts of energy efficiency programs suggests that efficiency investments in the ERIS scenarios would lead to the creation of 200-400 net jobs per year, or 3,500-6,500 by 2020 for moderate efficiency and aggressive efficiency scenarios, respectively. This benefit results from a combination of the trade jobs needed to produce and install efficiency measures, as well as the added purchasing power of customers whose energy bills are reduced. Conversely, efficiency tends to reduce jobs directly in the energy supply industries (electricity and gas) and indirectly in the reduced purchasing power resulting from the efficiency expenditures.

The jobs created tend to be located in the region where the efficiency investments occur. Thus, we expect that there would be a significant benefit to San Francisco employment. Note that some of the jobs gained in efficiency work and lost in energy supply could both occur within an energy utility such as PG&E, so it is possible that a utility might not experience much net change in employment, but rather of shift in the type of jobs. We do not have data on employment impact of renewable and distributed energy, but we expect that their impact would be neutral to slightly positive in the scenarios we consider here.

The potential for cost-effective EE and DG in San Francisco creates opportunity, but realizing this potential requires that EE and DG projects can be financed. Therefore, we conducted a detailed study of financial flows and returns to investors and other participants in a range of EE and DG projects in the residential, commercial and municipal sectors. The results indicate that:

- *New residential construction* presents a good opportunity for inexpensive mortgage financing. Ammortized energy cost savings can be shared between the builder and the buyer, as long as some of the value of energy efficiency can be captured in the sales price. If so, the builder can realize additional profit while the net of the buyer's total monthly mortgage and energy bill payments is reduced. Similar results apply to new commercial construction, but buyers' incentives are less clear if they do not occupy the building and instead pass all energy costs on to the tenants.
- *Commercial energy efficiency* can be highly cost-effective, but there are often split incentives between building owners and tenants. Energy service companies (ESCos) provide a vehicle for financing and implementation; however, government or utility incentives may be needed to increase the amount of efficiency measures that are cost-effective under expensive private financing.
- The financial success of *energy efficiency in municipal facilities* depends on whether the facility is a General Account customer with low power rates or an Enterprise Account customer with high power rates. While General Account customers themselves have little incentive to save cheap energy, the City (through SFPUC) can profit from implementing efficiency projects on behalf of these customers, as the saved energy is worth more if sold elsewhere. If the SFPUC implements efficiency projects for Enterprise Account customers, significant revenue is lost unless the customers' saving can be shared contractually to create a win-win deal.
- Due to high retail rates, *distributed generation in the commercial and municipal* (Enterprise Account) sectors can be profitable for third-party investors, if they can secure utility interconnection agreements and take advantage of multiple tax-based incentives and State rebates. DG at municipal facilities might also be able to employ low-cost municipal bond financing, such as that provided by Proposition H.

Even if all these financial mechanisms can be accelerated, there are still important categories of energy efficiency opportunities that can be captured through public policies and programs that enhance public-private cooperation. In the short term, the City needs to work with PG&E to capitalize on California's renewed commitment to make energy efficiency an essential part of the State energy program. Public goods charge (PGC) funding can be applied to energy efficiency programs, especially in the commercial sector, that are tailored to the City's needs.

Other innovative programs, which have proven successful in other states, can help San Francisco overcome barriers to energy efficiency in specific market segments, including difficult to reach segments such as existing multifamily housing. Some of the recommended programs include:

- Green buildings program for new construction to encourage, recognize, and eventually require high-performance green design, measured for example by the U.S. Green Building Council's LEED ratings, in new buildings (examples include Austin TX and Seattle WA).
- Commissioning and building operator training for commercial and municipal buildings, to capture cost-effective efficiency and performance improvements in the operation and control of buildings (examples include Portland OR and Southern California), supported by training of operations staff to identify efficiency opportunities and implement efficient practices.
- Turnkey programs to install efficient technology in multifamily rental and low-income housing, in which residents cannot afford or lack incentive to invest in energy efficiency, by providing building audits and technical assistance, financial incentives, and contractor screening (examples include Vermont and Oregon).
- Pay-As-You-Save (PAYS), an innovative program to finance customer costs of energy investments, which are repaid through the (energy or water) utility bill, spread over time and offset by energy savings, avoiding the initial-cost barrier that limits customer investment in energy efficiency and DG generally (examples include New Hampshire and Connecticut).
- Building energy certification to recognize and encourage efficiency improvements in new and existing buildings, and to provide a basis of comparison for buyers, realtors and lenders.
- Energy code training for building inspectors to improve the compliance and enforcement of voluntary and mandatory building energy codes, including the California Title-24 standard.
- Demand response programs, using critical peak pricing with automated control and two-way, real-time communication technology to enable customers to limit their power demand for short periods during critical periods when electricity supply is short and/or expensive.

Public policy and programs can also accelerate investment in distributed generation (DG). An urgent need is to streamline the process for meeting City planning codes and utility connection and system protection requirements. DG developers report that the cost and time needed to meet utility interconnection and protection requirements are high. For example, requirements that a DG source shut down when the building load does not exceed a minimum criterion, which is set higher than State standards, would prohibit DG operation so often as to make DG unviable. City arbitration could reduce barriers to DG, while ensuring the safety and stability of the grid.

Because the City already produces enough power at Hetch Hetchy to serve its municipal loads, there is no ready buyer for incremental generation or energy savings. The City can capture more of the value of future energy investments if it has a larger customer base. Possible mechanisms to acquire additional customers are municipalization, community choice aggregation, or variations of the municipalization structure, such as a municipal power authority, in which the City would assume the functions of energy procurement and resource development on behalf of customers.

Regardless of how the formal structure changes, or if the *status quo* prevails, San Francisco can benefit from cooperation to tap PG&E's technical expertise, the financial creativity of the private sector, the City's access to inexpensive financing, and citizen groups' community relationships. All these actors need to participate, to benefit, and at times to compromise, for San Francisco to succeed in implementing the ERIS portfolios and meeting the City's energy planning goals.

INTRODUCTION

The City of San Francisco is at a crossroads on energy policy, as it faces decisions about how to replace electricity from two aging, highly polluting power plants located at Hunters Point and Potrero Hill. Both the City's economic and environmental health are vulnerable to several risks. Low-income communities are particularly impacted by air pollution due to their close proximity to the power plants. The City's agreement with PG&E to close the oldest plant at Hunters Point could leave energy customers exposed to the exercise of market power by the single remaining owner of in-City generation at Potrero. Given the City's location at the end of a peninsula, there is limited capacity for transmission lines to import enough electricity into San Francisco as a substitute for power from Hunters Point. Finally, total reliance on natural gas and electricity markets exposes customers to energy price volatility, such as that experienced in 2000-2001.

To help clarify these complex and conflicting problems, and to prioritize the work and investment needed to begin to solve them, Rocky Mountain Institute (RMI) has worked with the City of San Francisco, through the Public Utilities Commission (SFPUC) and Department of the Environment (SFE) to assemble an Energy Resource Investment Strategy (ERIS) for the City and County of San Francisco.

The Energy Resource Investment Strategy (ERIS) is a set of energy resource portfolios, based on a range of possible future scenarios, that combine existing and future energy resources to meet San Francisco's need for adequate and reliable supply of electricity services, while minimizing costs and environmental impacts. The selection and prioritization of resources under a given scenario is based on the needs and constraints of the scenario context (e.g., gas costs, transmission capacity, etc.), as well as the availability of resource options and our evaluation of their cost, performance and consistency with the scenario definition (e.g., minimum cost, environmental justice, etc.).

The ERIS approach is a refinement of the methodology used for integrated resource planning (IRP),[3] in which demand-side management (DSM) measures such as energy efficiency improvements and distributed generation (DG) sources are considered as energy utility investments that can complement and compete with conventional, central supply technologies in energy resource planning. The ERIS approach is an even more locally-oriented, bottom-up method. This is more appropriate for addressing the situation in San Francisco, which has very particular circumstances affecting its energy supply and needs.

Because resource planning considers the future, it is always subject to uncertainty, which is addressed in the ERIS process using a scenario approach. By constructing scenarios, we can explore a range of distinct hypotheses about how San Francisco's energy future may unfold, based on internally consistent logic but somewhat different assumptions.

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[3] IRP analysis methods are explained in: J. Swisher, G. Jannuzzi and R. Redlinger, 1998. *Tools and Methods for Integrated Resource Planning: Improving Energy Efficiency and Protecting the Environment*, UNEP Collaborating Centre on Energy and Environment, Roskilde, Denmark.

The range of assumptions in the scenarios can express uncertainties regarding future states of the world, or they can express a range of choices that could be made to address the problem at hand. The initial RMI scenario analysis for San Francisco[4] used the latter approach, exploring several very distinct technological pathways and showing that San Francisco had more choices than had been widely recognized at the time. In this document, we used the former approach to address key uncertainties, such as technology costs and economic growth, that would influence energy resource decisions in San Francisco in the short (2006), medium (2013), and long term (2020).

[4] Rocky Mountain Institute, 2002. *An Energy Resource Investment Strategy for the City of San Francisco: Scenario Analysis of Alternative Electric Resource Options*, report to the San Francisco Public Utilities Commission.

GOALS FOR ENERGY PLANNING IN SAN FRANCISCO

In May 2001, a City Ordinance sponsored by Supervisor Sophie Maxwell was passed, directing the San Francisco Public Utility Commission (SFPUC) and the Department of the Environment (SFE) to prepare an Electricity Resource Plan (ERP) to implement all practical transmission, conservation, efficiency and renewable alternatives to fossil fuel generation in San Francisco. During the preparation of this plan, the SFPUC contracted with Rocky Mountain Institute (RMI) to help restart the municipal energy planning process by preparing a comprehensive Energy Resource Investment Strategy (ERIS). In the initial phase of this process, RMI assisted the staff of SFPUC and SFE in developing the ERP. The main quantitative input to the ERP was the result of a scenario analysis conducted by RMI, which established the framework for the ERIS and demonstrated that San Francisco has a range of electricity resource options available.[5]

The ERP provides a general framework for discussing policy goals, communicating the choices available to the City, and soliciting public input to the planning process. It was completed during 2002, after a period of public review and comment. Between November 2001 and August 2002, the SFPUC and SFE jointly hosted two rounds of neighborhood meetings to solicit input for the plan. During this time, the agencies also participated in public forums on energy policy with energy experts, planners, and business and community leaders. The purpose was to identify goals to guide the development of the plan and to provide information to the public on how the City gets its energy, the potential vulnerabilities the City faces, and the options available for developing electricity generation, transmission, energy efficiency and renewable technologies.

In the course of the public discussion surrounding the drafting of San Francisco's Electricity Resource Plan during 2002, eight goals for the City's energy future were identified:

1. *Maximize Energy Efficiency*. The public expressed a desire for more aggressive efficiency programs, based on the availability of energy efficiency technologies that are mature, available and cost-effective. Money saved on energy bills can be retained in the community and recycled in the local economy to create jobs.
2. *Develop Renewable Power*. The public expressed strong support for the City to pursue renewable resources aggressively, beginning with proven technologies such as solar panels and wind turbines. At the same time the City should consider the acquisition of newer technologies such as hydrogen fuel cells, and review the options for tidal energy. Renewable energy can help achieve the goals of reliability, affordable and consistent electric bills, reduced pollution, local control, and opportunities for economic development.
3. *Assure Reliable Power*. Reliability can be improved through the development of redundancy in generation and transmission resources, through electric peak load management, and through energy efficiency programs. It is important that forecasts of future electricity demand be accurate and regularly updated to avoid overbuilding

[5] Rocky Mountain Institute, 2002. *An Energy Resource Investment Strategy for the City of San Francisco: Scenario Analysis of Alternative Electric Resource Options*, report to the San Francisco Public Utilities Commission.

resources to assure reliability. The community linked reliability with local control, small-scale generation, and energy efficiency.

4. *Support Affordable Electric Bills.* There are two ways to reduce electric bills: by lowering the rate charged per kilowatt-hour, and by reducing the amount of electricity used, via energy efficiency. To keep bills low, the City was urged to help enable all classes of customers to participate in efficiency and peak reduction programs. There was public concern over the concentration of power plant ownership in the City, which supported arguments for more local control and smaller-scale generation, especially renewable sources.
5. *Reduce Air Pollution and Prevent Other Environmental Impacts.* Citizens expressed a strong desire to reduce air pollution associated with energy production in San Francisco. For this reason, a high priority objective is to shut down the Hunters Point plant. Concern was expressed that San Francisco should not export health risks elsewhere, nor create environmental impacts on the ecosystem of the Bay and other sensitive areas. In addition to reducing regulated pollutants, San Franciscans want to reduce their share of global warming impacts.
6. *Support Environmental Justice.* The low-income neighborhoods of Southeast San Francisco have historically borne a disproportionate burden of environmental impacts. Major sources of such impacts include emissions from the Hunters Point and Potrero power plants. The greatest concern is public health, especially that of children in Southeast San Francisco, who have higher rates of asthma than in other parts of the City.
7. *Develop the Local Economy.* San Francisco energy choices will affect the local economy. Each choice will affect the extent to which dollars can be kept circulating in the local economy through in-City manufacturing, production, distribution, and installation services. A robust and growing energy technology market in San Francisco would support new business enterprises and create jobs while reducing pollution.
8. *Increase Local Control Over Energy Resources.* Control over energy resources has taken on new significance with the failure of deregulation and the volatility of the energy market. Local control can be most effective through the promotion and development of small electricity generators. It is possible for the City to either own smaller power plants through the Hetch Hetchy Water and Power system, or to enter into contracts for the power. Local control can help facilitate energy management, long-term planning, public education, and economic development that would involve local labor and businesses.

CURRENT STATUS OF THE SAN FRANCISCO ENERGY SYSTEM

The Energy Resource Investment Strategy (ERIS) for San Francisco addresses the systems of supply and use of electricity and natural gas. The starting point for our analysis of future scenarios is the present system, which is described below.

Electricity Use in San Francisco

The majority of electricity use in San Francisco, and the largest contribution to peak demand, is in the commercial sector, as shown in Table 1. The City's municipal loads, including SFO airport, are also mostly building energy loads that are similar to those in commercial buildings, although municipal loads also include the Muni railway and the water and wastewater facilities. Residential customers use about 25% of San Francisco electricity, while industrial use is rather negligible. Commercial and municipal loads are shown in more detail Table 2 and Table 3.

Table 1. Sectoral breakdown of San Francisco electric use

Sector	2000 Total Electricity Consumption (GWh)	Share of Total Electricity Consumption (2000)	Coincident Summer 2000 Peak (MW)	Coincident Winter 2000 Peak (MW)
Commercial	3300	58%	670	470
Residential	1430	25%	135	285
Municipal	820	15%	120	125
Industrial	110	2%	20	20
Total	5660	100%	945	900

Source: PG&E

Table 2. Breakdown of San Francisco commercial building electric use

Building Type	2001 Total Electricity Consumption (GWh)	Share of Total Electricity Consumption (2001)
Colleges	63	2%
Food Stores	181	6%
Hospitals	151	5%
Hotel/Motel	261	8%
Miscellaneous	165	5%
Office	1901	59%
Restaurant	221	7%
Retail	218	7%
Schools	13	<1%
Warehouse	55	2%
Total	3230	100%

Source: Xenergy 2002

Note: 2001 commercial consumption was about 2% less than in 2000

Table 3. Breakdown of San Francisco municipal electric use

Building Type	2001 Total Electricity Consumption (GWh)	Share of Total Electricity Consumption (2001)
Airport Commission	317	39%
Muni Railway	121	15%
Water Pollution Control	71	9%
Water Supply	51	6%
SF General Hospital	38	5%
Public Schools	33	4%
Port of San Francisco	18	2%
Moscone Convention Ctr	17	2%
Other	155	19%
Total	820	100%

Source: SFPUC

Figure 11 shows the historical progression of total electricity use in San Francisco. Demand has moderated somewhat since 2000 due to the economic recession.

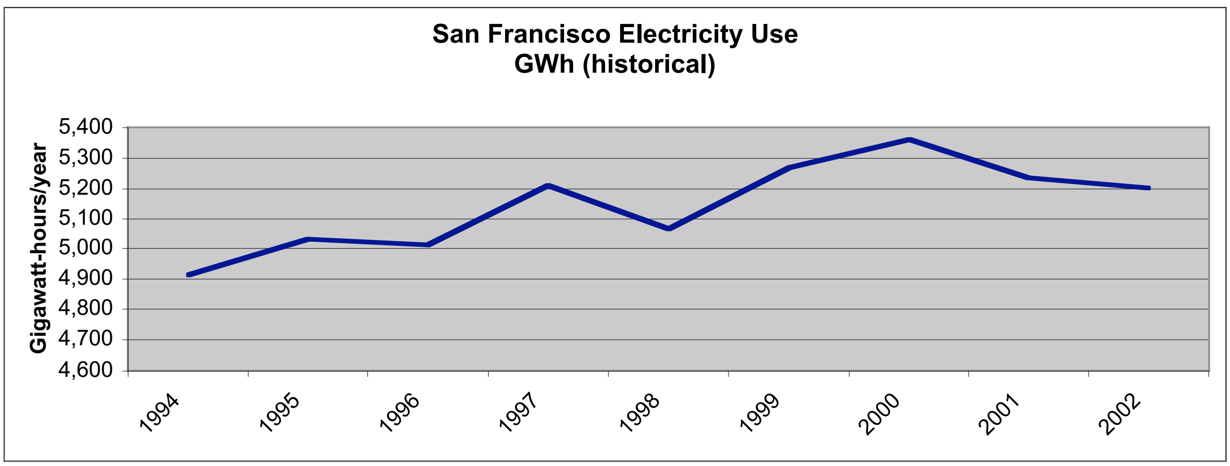


Figure 11. San Francisco historical electricity use. Source: California Energy Commission

Note: The CEC data do not include SFO airport, which uses about 300 GWh per year.

Peak Electric Demand in San Francisco

The capacity requirements for electricity generation, transmission and distribution represent a substantial share of the total cost of electricity. These requirements are driven, not by the total consumption of electricity, but by the maximum instantaneous demand level. Moreover, power supply capacity and overall reliability in San Francisco and the Northern Peninsula is limited by the transmission capacity that provides imported power into the City, including power generated from the City's own hydroelectric resources at Hetch Hetchy.

Evaluation of annual peak demand in San Francisco is complicated by the generally mild and consistent climate on the Peninsula. Summer peak demand in San Francisco is driven by commercial air conditioning and occurs during the hottest days, which can occur from mid-May through mid-October. A winter peak also occurs in December or January, driven by building heating and lighting loads. Although it is typically colder in January, the winter peak usually occurs in December, probably due to the addition of holiday lighting loads.

Peak demand increased in 2000 by 3 percent and then declined in 2001 by 8.5 percent, dropping below 1997 levels. The sharp economic downturn in 2001 occurred at the same time that a statewide campaign for energy conservation was being launched to avoid power outages. Figure 12 shows historical peak demand for electricity in San Francisco over the past 10 years.

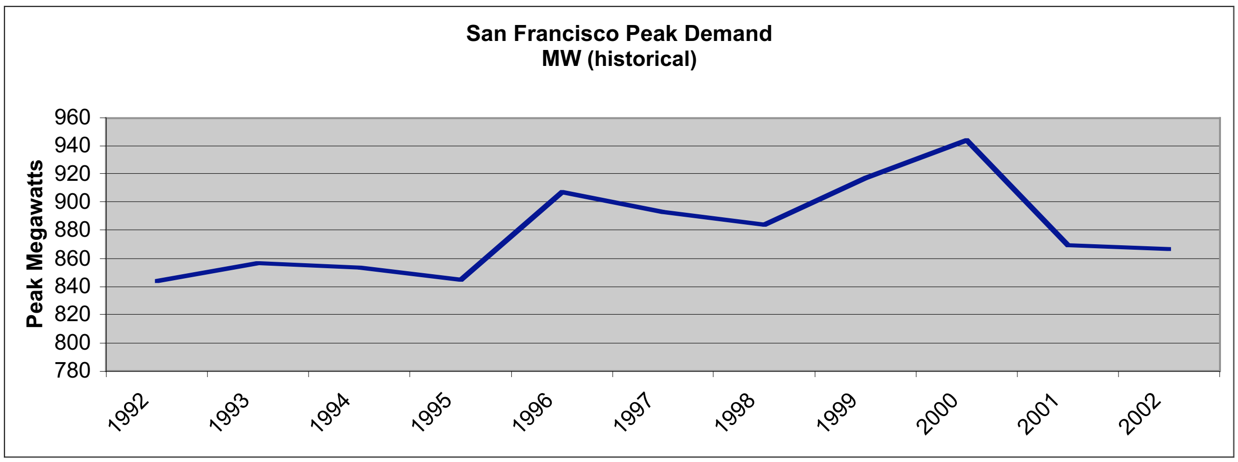


Figure 12. San Francisco historical peak demand. Source: PG&E

Figure 13 shows the monthly peak electric demand in San Francisco during 1998-2001. Because most City residents do not have air conditioning equipment, the summer and winter peaks are actually close enough in magnitude that in years with an unusually cool summer (e.g., 1998) or with extraordinary conservation efforts (e.g., 2001), the summer peak is depressed, and the annual peak occurs during the coldest period in winter. In general, however, peak demand has been relatively stable over the past decade.

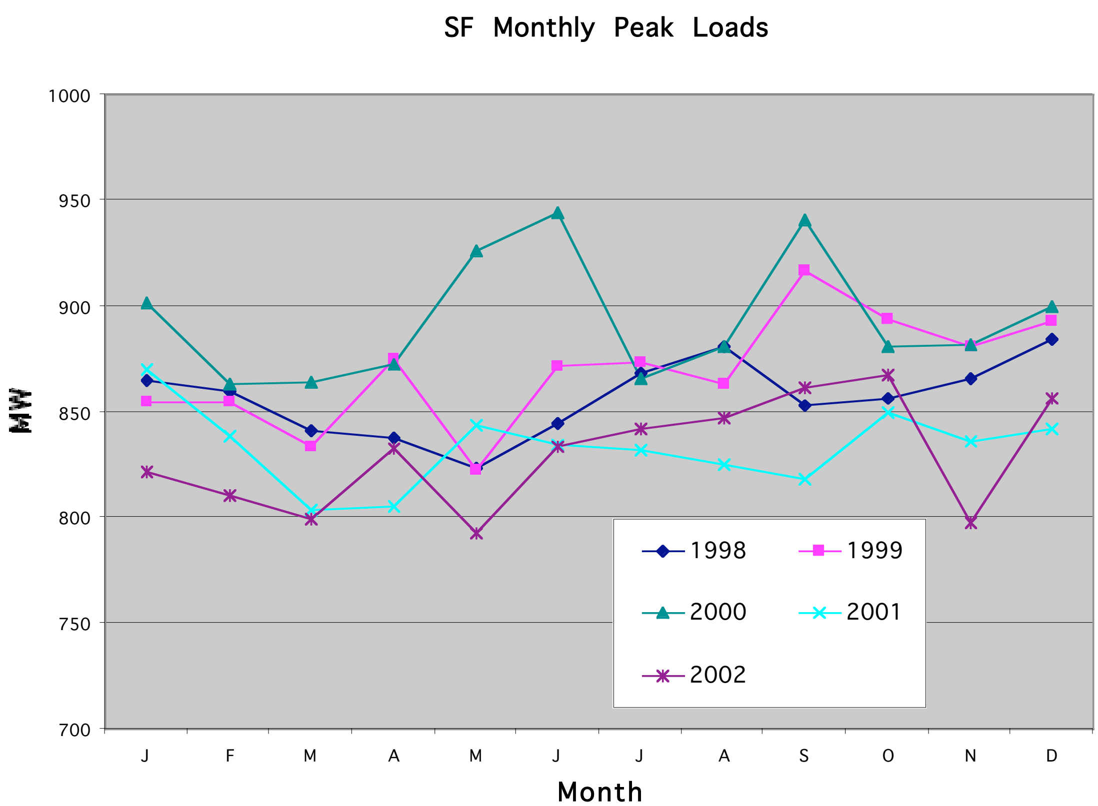
Summer vs. winter peak demand in San Francisco

The summer peak demand occurs in San Francisco during the hottest days, which can occur from mid-May through mid-October, and are driven by commercial air-conditioning loads (Figure 14). A winter peak also occurs in December or January, and is driven by space heating and other residential loads. In 2000 and in 2002, the winter peak was only about 45 MW lower than the summer peak (see Figure 15).

For planning purposes, we consider the summer-autumn peak to be the annual peak demand that must be met by the supply system. This is because 1) the highest summer peaks tend to exceed the highest winter peaks, and 2) the summer peak tends to be coincident with the PG&E system peak, which also strains the electric generation and transmission capacity beyond the San Francisco peninsula.

We cannot, however, overlook the winter peak. If either solar generation or summer peak load management shaves 3-5% off the maximum demand level, the remaining winter peak could become the primary annual peak!

Figure 13. Monthly peak electric demand in San Francisco, 1998-2002



This relatively small difference between the summer and winter peaks is significant in that it places an upper bound on the amount of capacity than can be provided by summer peak load management or by solar generation that can be installed in San Francisco. Because the winter peak occurs at nighttime, solar is not productive to reduce winter peak demand in the City. Once the summer peak in the City is reduced to the level of the winter peak, any additional load management or solar electric capacity installed would not make a significant contribution to peak load-serving capacity in the City.

Figure 14. Average San Francisco commercial load profiles in September, 2000

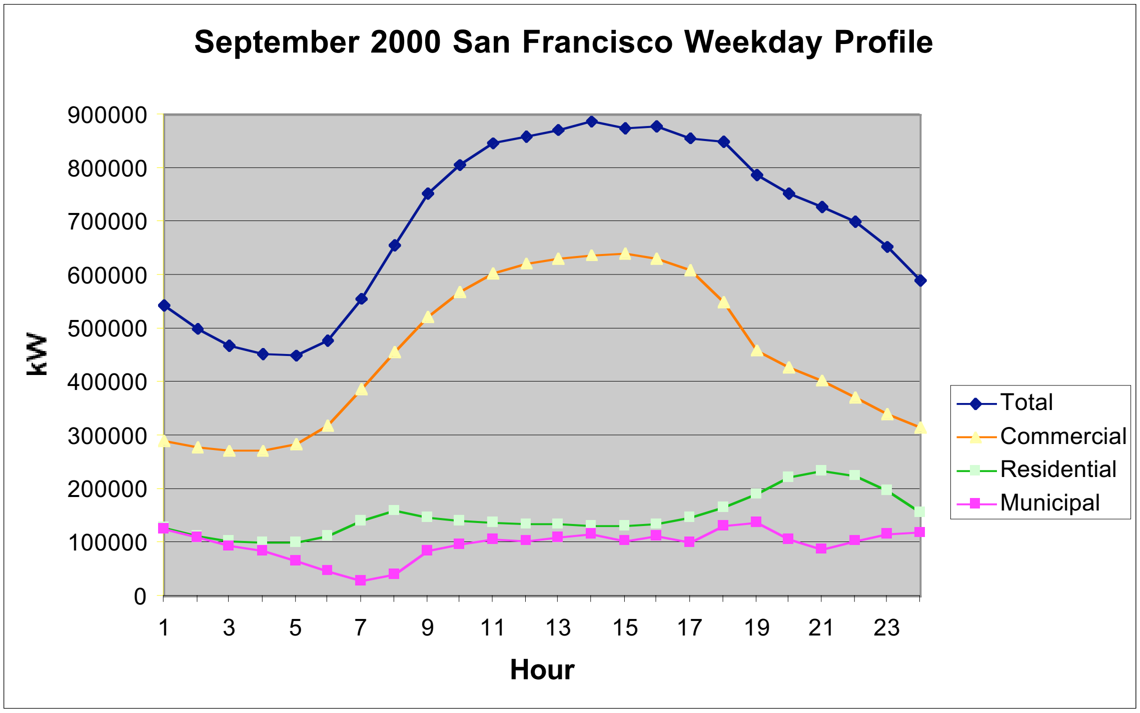
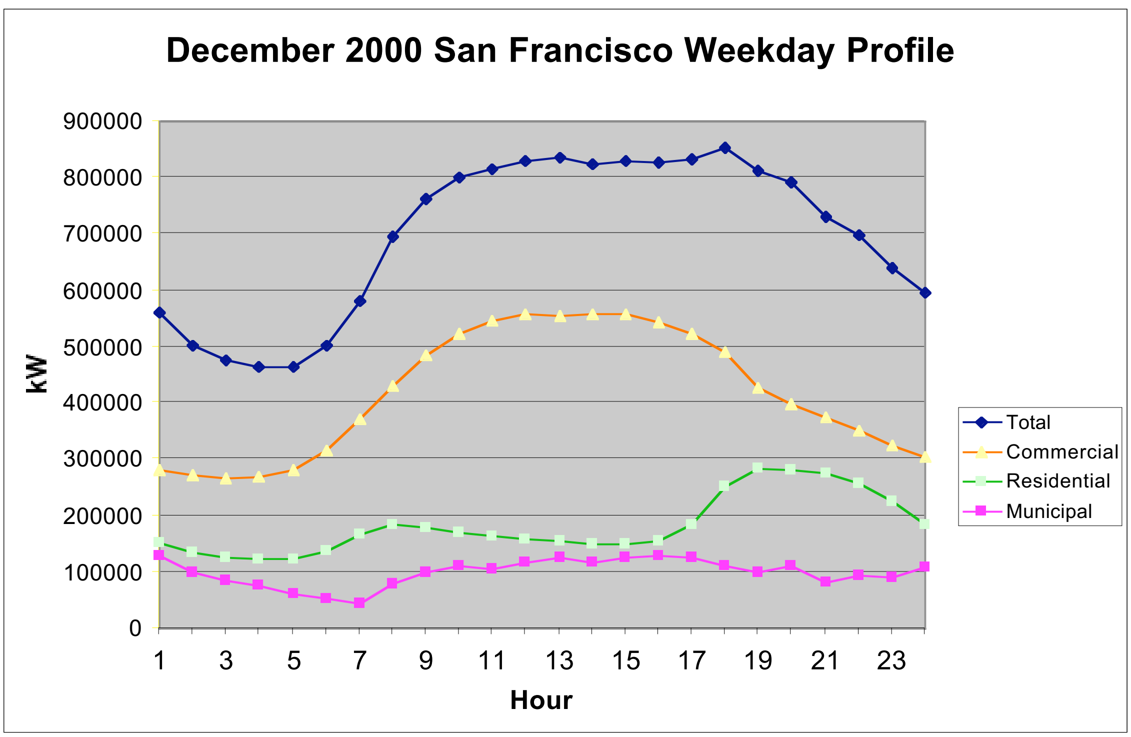


Figure 15. Average San Francisco electric load profiles in December, 2000



Electricity Supply in San Francisco

Pacific Gas and Electric Company (PG&E) delivers gas and electricity to all customers and serves as the retail energy provider for about 84% of the electricity and about 97% of the gas supplied to San Francisco. The rest is used by municipal facilities whose retail provider is Hetch Hetchy Water and Power (HHWP), which is a bureau of the San Francisco Public Utilities Commission (SFPUC).

The City of San Francisco provides electricity to the Bay Area through the Hetch Hetchy Water and Power project. The City began generating power in 1921 in compliance with the federal Raker Act, which granted the City rights to Federal lands in and near Yosemite National Park for the development of water and power supply facilities, including the construction of O'Shaugnessy Dam at Hetch Hetchy.

The City operates three powerhouses – Mocassin, Holm and Kirkwood – that are capable of producing 401 MW of electricity when their reservoirs are full. During a year with average precipitation, the Hetch Hetchy project produces about 1.7 GWh of electricity.[6] In addition to the generation facilities, the City owns about 150 miles of high voltage transmission lines that link the power plants with the California grid at Newark (see Figure 16). Thus, although San Francisco produces more electricity that its municipal customers use on an annual basis, the City must rely on PG&E's transmission grid to deliver power into the City.

The Raker Act requires Hetch Hetchy power that is surplus to the City's municipal needs be made available at cost to the Modesto and Turlock Irrigation Districts to meet their municipal needs. Any power that is excess to both the municipal needs of San Francisco and the Districts can be sold to public power agencies. In practice, most of this power was sold to Modesto and Turlock to meet residential and business loads served by the Irrigation Districts. The Raker Act prohibits the sale of Hetch Hetchy-generated electricity to investor-owned utilities for resale. Therefore, the City cannot sell any surplus power to PG&E.

Until about 1985, power production was mostly a by-product of reservoir releases to deliver water to the Bay Area. This mode of operation generated large amounts of electricity during the February-to-June period and sold this power to Modesto and Turlock at cost. In the early 1980's, the City recognized that energy saved in City facilities could be sold at a higher rate, thus yielding revenue for the City's general fund and reducing costs to City departments. In 1982, the *Energy Policy* of the City's General Plan identified energy-efficiency in both the public and private sectors as a priority.

Negotiations with PG&E and the Modesto and Turlock Irrigation Districts resulted in new contracts for the delivery of power to the Districts. The City agreed to buy power from PG&E to firm 260 megawatts of Hetchy's generation capacity, and the Districts agreed to purchase all

[6] 1 GWh = 1000 MWh = 1,000,000 kWh are units of energy. 1 MW = 1000 kW = 1,000,000 watts are units of power, or the rate at which energy is converted or used.

firm power not needed by the City to supply its own facilities. Power purchased by the Districts under this new agreement was set at rates that were designed to produce a modest profit for San Francisco, which averaged about $34 million annually during 1991-2000.

Starting in 1998, the restructuring and partial deregulation of the California electricity industry required the City to buy power needed to firm up its delivery requirements from the short term "spot" energy market.[7] By December 2000 the wholesale power market became completely dysfunctional, and in the budget year 2000/2001 the City ended up paying $154 per megawatt hour for electricity, nearly five times as much as it had paid in 1999/2000. To lock in a price for the power to firm up San Francisco's obligations for serving its own municipal load and the Districts' contractual requirements, the City entered into a five-year power purchase contract with Calpine.

Electricity markets and the regulatory landscape

The partial deregulation of the California electricity industry began in 1995, when the California Public Utilities Commission (CPUC) issued a decision that created the California Independent System Operator (CAISO) and the Power Exchange (PX) and ordered utilities to divest most of their fossil fuel-fired generation. Also, utilities were obligated to sell their remaining generation (mostly hydro and nuclear) into the PX and then purchase to meet customer needs from the PX. In 1996, Assembly Bill (AB) 1890 was passed, providing a legislative foundation for electricity restructuring in California.

The Federal Energy Regulatory Commission (FERC) issued Order 888 to encourage the formation of independent system operators (ISOs) for regional transmission systems and to allow power generators to price wholesale electricity at market prices rather than regulated rates. AB 1890 and Order 888 provide for FERC regulation of the transmission system in California, while utility distribution systems remain under CPUC jurisdiction.

When power prices skyrocketed in 2000-2001, Governor Davis authorized the California Department of Water Resources (DWR) to purchase power for customers of California's utilities, and it entered into a series of long-term contracts at prices substantially above the cost of producing electricity. As part of its remedy for California's dysfunctional market, in December 2000 FERC revoked the utilities' requirement to buy all power through the spot market, leading to the demise of the PX.

Currently, the thermal power plants at Hunters Point and Potrero Hill in San Francisco are needed to operate in order to provide local area reliability. As a result, their owners could demand prices far in excess of their costs. To mitigate the exercise of local market power that these units possess, the CAISO has entered into Reliability Must Run (RMR) contracts with these generation owners (PG&E and Mirant, respectively).

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[7] "Firm" power is electric energy that can be delivered at any time the customer requires. If a power supply is intermittent, such as that from 100% wind or hydropower resources, additional power must be made available to balance this source. The energy to firm up an intermittent source comes from other sources that either deliver power at times that are complementary or that can be started ("dispatched") on demand.

Meanwhile, the CAISO has proposed a transmission pricing model based on congestion, which would lead to higher electricity rates in San Francisco and increase the incentive to develop new generation in the City. Similarly, the addition of new transmission capacity to the San Francisco Bay Area is needed to protect San Francisco from price increases associated with the potential adoption of a congestion pricing. While the California ISO is refining its market proposal, its future is uncertain. The FERC is pushing for the formation of multi-state regional transmission organizations (RTO) to enable more efficient wholesale markets. The benefit to San Francisco of an RTO would be minimal, because its ability to import power is limited by available transmission capacity.

Table 4. Energy agencies and their responsibilities

Entity	Jurisdiction
Independent System Operator (ISO)	Operates the transmission system. Sets reliability criteria, issues RMR contracts, approves transmission projects
California Energy Commission (CEC)	Issues power plant licenses, sets energy efficiency standards
California Public Utilities Commission (CPUC)	Regulates distribution system. Sets electric rates, approves ratebasing of transmission and efficiency projects
Bay Area Air Quality Management District (BAAQMD)	Enforces Clean Air Act emissions standards, issues permits, regulates emissions trading
Federal Energy Regulatory Commission (FERC)	Sets electric rate caps, regulates ISO
California Power Authority	Provides financing for various renewable, reliability, and efficiency projects
Governor	Appoints ISO, CEC, CPUC board members
State Legislature	Enacts energy legislation (eg. 1996 deregulation bill - AB 1890, proposed aggregation bill- AB117)
Pacific Gas and Electric Company (PG&E)	Owns/operates Hunters Point power plant. Owns/operates electric distribution system in SF, owns most of the transmission system in Northern California. Administers most PGC funds
Mirant	Owns/operates Potrero power plant

Electricity service obligations and District power contracts

Hetch Hetchy Water and Power's electricity customers include CCSF offices and services, including the Muni railway, water and wastewater facilities, as well as San Francisco International Airport (SFO) and airport tenants. Airport tenants include private enterprises such as gift and food shops that rent or lease space in SFO. Additionally, CCSF is required by the Raker Act of 1913 to sell power generated in excess of City municipal needs at cost to two Central Valley irrigation districts and public agencies – the Modesto Irrigation District (MID) and the Turlock Irrigation District (TID).

The districts have first right of refusal to this excess HHWP power but are not obligated to buy the excess power. They may refuse the excess electricity offered to them, if for example they can purchase the power on the wholesale market more cheaply, which is unlikely. MID receives 2/3 of the total and TID always receives 1/3 of the total power sold to them by the City. Currently, the City's power obligations include a firm generation obligation of 260 MW to all of its customers, including City loads and the districts, with excess beyond this firm obligation divided equally between the districts and the airport tenants.

The City tries to use its own hydroelectric power first serve its customers. During those months of the year when the City's hydroelectric generation capacity cannot generate enough power to meet its obligations, the City will sell power from its power purchase contract with Calpine, then purchase from the wholesale spot market after the Calpine power is also spent.[8] After the power purchase contract with Calpine expires in 2006, the City will have to purchase from the power market to fulfill its power obligations above what it can generate. Any excess left after fulfilling its power obligations is sold to the power market. Below we describe in more detail San Francisco's electricity service obligations and district power contracts.

From present to December 2007

Under the existing contracts between HHWP and the irrigation districts, the obligations and priorities for electric service are shown in Table 5.

District class 1 loads are irrigation and municipal loads. District class 3 loads are retail, residential and commercial loads. Power that HHWP generates is used to first serve all of San Francisco's municipal loads - the city's offices and services including SFO. After the City loads are served, HHWP must supply power to the irrigation districts' (MID and TID) class 1 loads. Next, HHWP must service 100% of the airport tenant loads after district class 1 obligations are filled. According to Table 5, this implies that class 1 districts, the Airport tenants, and much of class 3 loads of both MID and TID irrigation districts can be served within the 260 MW obligation at any time during the year.

[8] HHWP purchases power from Calpine according to the following schedule: Jan – March, 40 MW; April – June, 30 MW; July – September, 55 MW; October – December, 75MW. The schedule of power purchases from Calpine was recently negotiated in early 2003 to complement the pattern of hydroelectricity generation of the city. Prior to the contract renegotiations, HHWP purchased 50MW from Calpine year-round and 24 hrs/day.

Table 5. Summary of HHWP obligations 2003 - Dec 2007

Service Priority		Demand, MW
1	City loads including SFO	130
2	MID Class 1	50
3	TID Class 1	40
4	SFO tenants	19
Subtotal		**239**
5	MID Class 3	80
6	TID Class 3	35
Subtotal		**110**
Grand total		**349**

During the dry season (July - January), HHWP's hydroelectric capacity cannot always generate enough power to meet all of its customer obligations. If HHWP cannot generate 260 MW, for example during a dry season or drought conditions, HHWP can use its contractual power purchased with Calpine to meet its firm obligations. If the Calpine power is still not enough to meet HHWP's firm obligations, additional power must be purchased from the wholesale power market (NP15). Note that the City is obligated to sell Calpine power to the districts at a loss. Once the power purchase contract with Calpine expires in 2006, the City will have to purchase power from the wholesale market to serve all of its 260 MW firm obligations.

During the wet season (February – June), HHWP can typically generate up to its 260 MW firm obligation to serve San Francisco's municipal loads, some of the districts' loads, and the airport tenants. San Francisco's city offices and services are served first. Hydroelectric power generated above the city demand is split half to the airport tenants, half to the districts. Class 1 receives power first, then class 3. HHWP needs to purchase additional power on the market to serve any airport tenant load not met by the excess hydro. If the MID or TID refuses any of the excess offered to them, HHWP can use it to serve the airport tenant load and sell the excess to the market.

January 2008 and beyond

HHWP recently renegotiated its power contract with MID and is in the process of renegotiating its power contract with TID. The power contract renegotiations involve absolving the obligation in 2008 to serve the irrigation districts above City loads up to 260 MW and serving only the districts' municipal and irrigation needs (Class 1) if excess hydropower is available. Retail, residential and commercial loads (Class 3) in the irrigation districts would not be served. If the negotiation with TID is successful, we assume that the HHWP obligations to serve both MID and TID will be as described below. If not, only MID's obligations will be as described below and we assume that TID's contract reverts to the existing agreements as described above (present to 2007).

Starting January 2008, HHWP will serve San Francisco's municipal loads with the hydroelectric power that it can generate during the dry season and purchase additional power from the market as needed to serve any remaining City loads. Additional power must be purchased as needed to serve airport tenant loads if no excess HHWP power is available. Note that TID class 1 loads will need to be served if contract renegotiations are not successful.

Starting January 2008, HHWP will serve San Francisco's municipal loads and airport tenant loads. Excess hydropower will be offered to the irrigation districts to serve class 1 loads as available. Once class 1 loads are met, any additional excess will be sold to the power market, including any power that the districts refuse to purchase. If TID contract renegotiation is unsuccessful, TID loads will need to be served up to 260 MW, and 1/6 (50% x 1/3) of excess hydro will be offered to TID, and the remainder to airport tenants.

Discussion of HHWP power contracts

Our purpose in analyzing San Francisco's power contracts is to determine whether the City has an economic incentive to conserve electricity and how much a kWh of energy saved is worth to the City. Figuring the dollar value of each kWh will help the City prioritize energy efficiency projects and distributed generation technologies for future implementation.

The dilemma faced by HHWP under the existing contract obligations is that HHWP must offer any excess hydroelectric generation to the irrigation districts. As such, there is little incentive to encourage San Francisco's city customers to conserve energy, as the energy saved would have to be offered to the districts at a low price. Irrigation districts pay for HHWP power at the cost of generation, which is \$17/MWh. In contrast, San Francisco's General Account municipal customers pay \$35/MWh, and its Enterprise Account municipal customers (e.g., SFO) pay about \$140/MWh.[9] Thus, the current structure of the city's contracts is such that it can lose significant income by encouraging energy efficiency, particularly among its Enterprise Account customers, who also tend to be the larger municipal energy customers.

In the near term, the Enterprise Account customers should have an incentive to reduce their energy consumption, as they are paying the highest rates of all the City customers. However, such energy savings would lead to a significant loss in revenue for the City. There is a possibility for HHWP to encourage efficiency among its General Account customers on the assumption that they may be able to transfer the power to the Enterprise Account customers.[10] However, this is now possible only during some dry months of the year when HHWP does not

[9] For the sake of simplicity, the City has calculated an average retail rate of 8 cents/kwh, taking into account the prices charged for the General Account and Enterprise Account customers, transmission, distribution, scheduling, and grid management charges. This bundled rate assumes that changes in transactions of city efficiency projects have a small impact on load, that the district energy contracts are still in place, and third markets such as community aggregation or municipalization are not yet in place. Thus, the cost effective level for city projects prior to 2008 when the district contracts are renegotiated, are assumed to be 8 cents per kwh.

[10] Enterprise Account customers are those city departments such as the water department, the airport, and the zoo, that can generate their own revenue when passing their energy costs on to the public (in the form of water rates, airport fees, concessionaire permits, etc.). These city departments are charged the market rate for electricity. General Account customers are those city departments that are charged at the HHWP wholesale cost of generating electricity.

generate excess power. It is also only possible up to the total City load of 130 MW, beyond which saved energy will be offered to the districts at a loss to HHWP. During the wet months there is no incentive for HHWP to help its customers conserve electricity.

The City's dilemma will be ameliorated when the new contract terms go into effect in 2008 and reduce the City's power service obligations to the irrigation districts. In 2008, HHWP will no longer have a 260 MW minimum firm obligation to both the City and districts. Therefore it will not be required to purchase firm power up to 260MW from the market. The potential for selling excess power to the market at higher rates than the districts pay will be increased. The only problem is to find or create a new customer market that will pay HHWP higher rates.

The city's contract obligations are illustrated in detail in Appendix A.

Generation of Electricity in San Francisco

Figure 16 shows the physical configuration of the main power supply resources that serve the City of San Francisco. The existing sources of power generation in San Francisco are two steam-turbine power plants that run on natural gas (Potrero Unit 3 and Hunters Point Unit 4) with a combined capacity of 370 MW and four smaller combustion-turbine (CT) peaking power plants that use diesel fuel (see Table 6) with a combined capacity of 208 MW.

All of the existing generation units are old, unreliable and high in emissions. The plants will face increasing challenges in meeting air quality requirements in the future. Potrero Unit 3 began operations in 1965 and is now beyond the expected 30-year life of a steam thermal power plant. Hunters Point unit 4 is 44 years old. In addition, the remaining units at the Potrero plant need to be retrofitted with more advanced emission control equipment if they are to continue operating beyond 2004.

The City and PG&E have agreed to close Hunters Point plant as soon as the City's loads can be served reliably without it. This condition could be realized by adding either generation capacity in the City or transmission capacity into the City. The need for new supply capacity can be reduced by limiting peak power demand through demand-side management (DSM) measures to improve energy efficiency and control peak loads.

Figure 16. Location of major electricity supply resources serving San Francisco. Source: SFPUC

Table 6. Existing major generation source in San Francisco

Generator Plant	Capacity	Type	Fuel	Status
Potrero Station				
Unit 3	207 MW	Steam	Natural gas	Operating, NOx emission limit
Unit 4	52 MW	CT	Oil	Operating <877 hours/year
Unit 5	52 MW	CT	Oil	Operating <877 hours/year
Unit 6	52 MW	CT	Oil	Operating <877 hours/year
Hunters Point Station				
Unit 1	52 MW	CT	Oil	Operating <877 hr/yr until 2005?
Unit 2		Steam	Natural gas	Closed
Unit 3		Steam	Natural gas	Closed
Unit 4	163 MW	Steam	Natural gas	Operating, NOx emission limit, until 2005?

Given the geographical location of San Francisco and the age of the two principal power plants serving the City, the CAISO has adopted special criteria to assure reliable electric service for San Francisco. Those criteria require that San Francisco have sufficient power generating capacity in the city to meet load whenever the largest power plant fails at the same time the transmission line with the largest import capacity is unavailable or vice versa.

These criteria mean that there need to be sufficient resources in San Francisco to keep the lights on if Potrero Unit 3 breaks down when Hunters Point 4 is out of service for a maintenance overhaul, and after it has been retired. In addition, the criteria assume that one of the four existing CT peaking plants will not be able to quick start. Under these conditions, the three in-City peaking plants would be used in combination with the import of electricity. Currently, a maximum of about 800 megawatts of San Francisco load can be served under these conditions. As long as Hunters Point is in operation, this load-serving capacity is about 950 MW.

Transmission of Electricity to San Francisco

At present, constraints on transmission capacity into the City limit the amount of power that can be imported from sources outside the City, including San Francisco's own sources at Hetch Hechy. High voltage transmission lines converge at the San Mateo substation from the south and from the east. From the south, transmission lines from the Tesla, Newark and Ravenswood substations connect into the San Mateo substation. From the east two transmission lines cross

San Francisco Bay and connect at San Mateo (see Figure 17). Power flows from the San Mateo substation northward to San Francisco through one underground 230 kV transmission line, five overhead 115 kV transmission lines and one 60 kV transmission line to the Martin substation at the San Francisco-San Mateo County line, which will be upgraded to 115 kV.

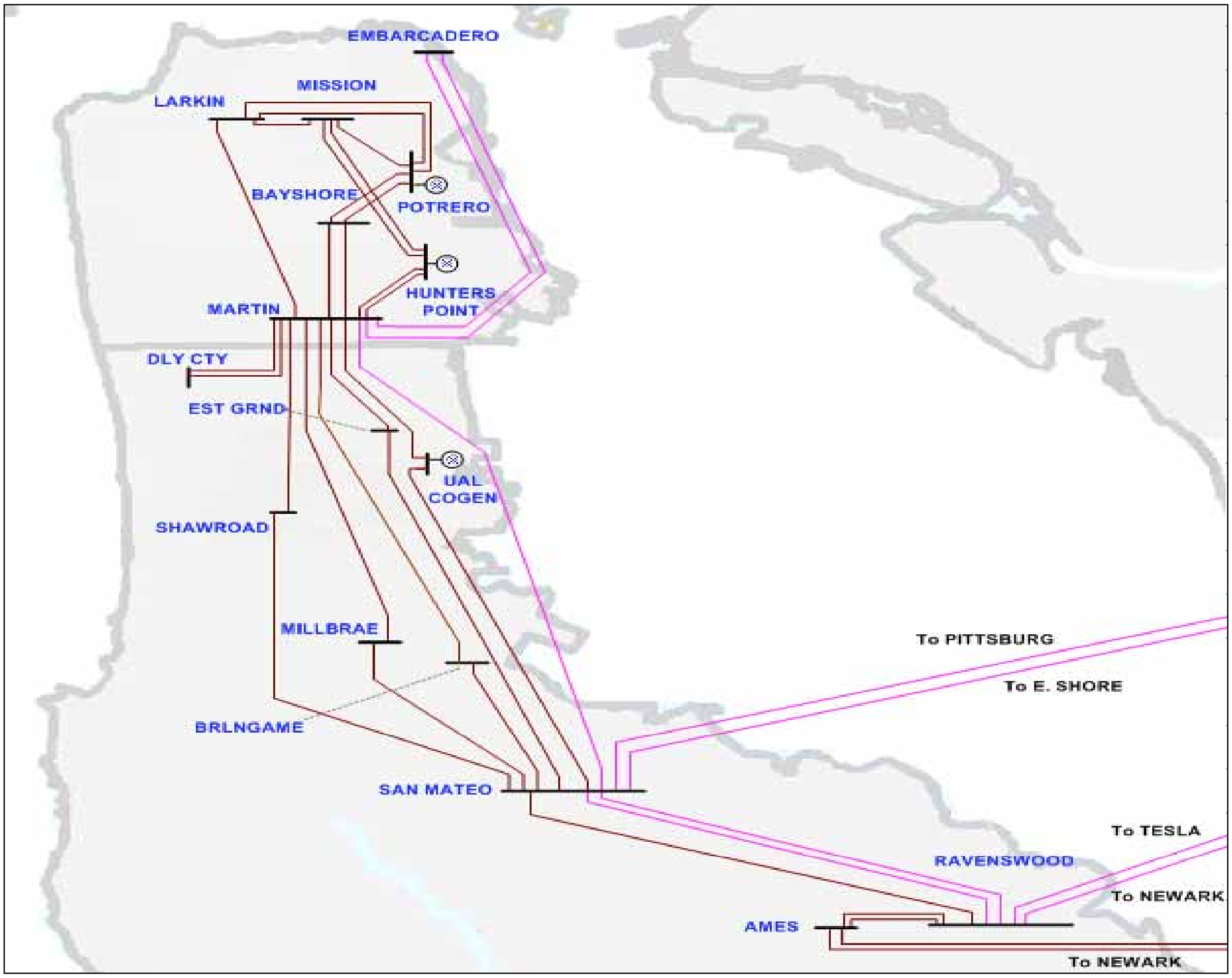

Figure 17. Schematic of the Peninsula Electricity Transmission Network

Total existing transmission capacity into the Martin substation is about 1250 MW under normal operating conditions, and 1500 MW under emergency conditions (which can be maintained for up to 30 minutes). For example, a San Francisco transmission planning study shows that a City load of 1057 MW,[11] plus 258 MW of net Peninsula loads, could be served with the only in-City generation coming from the peaking units at Potrero, implying a total import capacity into the City of about 900 MW.

[11] California Independent System Operator (Cal-ISO), 2000. *San Francisco Peninsula Long-Term Electric Transmission Planning Technical Study*, Final Report, October 24, www.caiso.com. The case sited is the "2004 Heavy Fall conditions, minus 400 MW generation" case, p.25.

However, this does not mean that the system can be operated to import 1250 MW of power under normal conditions, because the loss of any of this capacity would expose the City to too much risk of outages. Rather, transmission operates under first-contingency planning conditions, which dictates that the maximum load can be met after the loss of the largest component (i.e., one 230-kV line or two 115-kV lines). In addition, the system is designed to operate normally with the largest generation unit off-line at the same time. These are the criteria required by the CAISO for reliability planning regarding the San Francisco power supply system.

Under this condition, about 900 MW of load can be served north of San Mateo with adequate reliability. Netting out 280 MW load served on the northern Peninsula (in 2002), the City's present import capacity is about 620 MW. As the Peninsula load increases, the net import capacity to the City will decrease accordingly, as these loads are served from the same source. On the other hand, generation at the airport or elsewhere on the Peninsula can help to increase net import capacity, although the benefit per MW of generation is less than for in-City sources.

The Martin Substation is connected to two in-City transmission systems, a 230 kV system and a 115 kV system. The 230 kV system serves the downtown area through a single substation, the Embarcadero substation (see Figure 17). The remaining city electrical loads are served by the 115 kV system through four substations: Larkin, Mission, Potrero (adjacent to the Potrero Power Plant), and Hunters Point (adjacent to the Hunters Point Power Plant). All the substations are owned and operated by PG&E.

Distribution of Electricity in San Francisco

From the five transmission substations in San Francisco, electricity is distributed throughout the City by a lower-voltage (about 12 kV) distribution system. Most of the City is served by a radial distribution configuration, in which the local distribution feeder lines are fed from a single source at one of the substations listed above. However, the downtown business district, which comprises Market Street and areas within a few blocks, are served by a networked system that can be supplied by more than one source, thus increasing reliability.

Natural Gas Demand and Supply

Natural gas consumption in San Francisco consists of direct and indirect consumption. Direct consumption refers to natural gas that is burned at the end use level, such as heating a home; indirect consumption refers to natural gas that is burned to first produce electricity, then delivered to consumers at the end use. In-City electricity generation makes up 25% of the total natural gas consumption in San Francisco.

The residential sector is by far the largest category of natural gas customers, accounting for 53 percent of direct use and 41 percent of total (direct plus indirect) consumption (see Figure 18). Commercial buildings use approximately 26 percent of direct use. The combination of industrial and municipal consumption accounts for 15 percent of the annual direct total.

PG&E provides service to residential and small to medium commercial natural gas users, which are considered "core" gas customers. Customers that use more than 25,000 MMBtu (24 MMcf) per year – large commercial, industrial, and power plants – are considered "non-core" gas customers. Gas service is guaranteed for core customers. While non-core customers enjoy a lower gas service rate than core gas customers, they may be asked to curtail their consumption during extreme weather events so that core customer service is not disrupted.

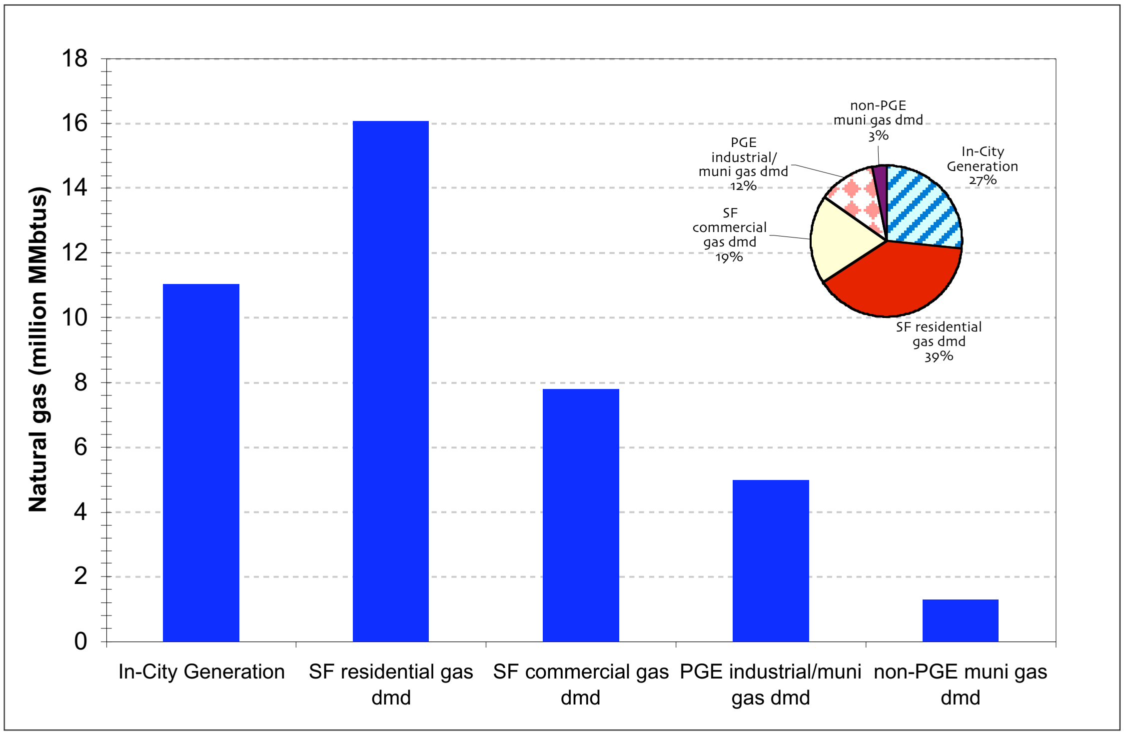

Figure 18. Estimate of 2002/2003 natural gas consumption in San Francisco

San Francisco's municipal buildings and functions use gas supplied by PG&E and by the State through the Department of General Services (DGS) Natural Gas Program. City buildings can be either core or non-core gas customers. PG&E provides core service to the City and the DGS provides both core and non-core service for City departments.

Table 7 shows estimates of natural gas consumption in San Francisco for 2002. Direct gas consumption data are provided by PG&E for all PG&E customers. Data on municipal gas service supplied by the DGS are provided by the SFPUC.

Gas supply to San Francisco is imported from Canada through PG&E-owned pipelines. Additional supply is available from the Rocky Mountain region, the Southwest (Texas and New Mexico) and in-state California production, also through PG&E-owned lines. All of San Francisco's natural gas is transported up the Peninsula beginning at the Milpitas Terminal. Three local transmission lines run north from the terminal up the Peninsula.

Table 7. Estimate of natural gas consumption in San Francisco, 2002

Customer	Gas Use (billion cf)	Gas Use (trillion Btu)
Hunters Point 4 (max load)	1.7	1.7
Hunters Point 4 (min load)	2.7	2.8
Potrero 3 (max load)	2.0	2.0
Potrero 3 (min load)	3.5	3.6
SF residential gas use	15.7	16.1
SF commercial gas use	7.6	7.8
PG&E industrial/muni gas use	4.9	5.0
Non-PG&E muni gas use	1.3	1.3
Total	39.1	40.0

Natural gas demand and supply, 2004-2020

According to the CEC's 2002 California Gas Report for Northern California, natural gas demand is projected to grow by 0.8 percent per year in the residential sector and by 1 percent per year in the commercial sector. Given these assumptions, the City is expected to demand approximately 54,000 MMcf (55 trillion Btu) per year in 2020, without taking end-use efficiency improvements into consideration.

PG&E plans for a spare supply capacity of approximately 15% in its backbone transmission system for the near term throughout the pipeline transmission network to serve core customers during extreme weather events.[12] An engineering study of natural gas supply for the proposed Mirant natural gas-fired combined cycle gas turbine (CCGT) plant determined that the existing gas infrastructure into the Potrero site would be adequate to run both the existing Potrero unit 3 and the proposed CCGT power plant, provided that Hunters Point unit 4 is shut down.[13] At normal full operation, the proposed CCGT plant would consume approximately 3.6 MMcf/hr (3700 MMBtu/hr). Assuming a capacity factor of 0.8, it would consume approximately 25,000 MMcf (26 trillion Btu) per year.

As such, natural gas supply capacity in San Francisco appears to be adequate in both the near and long term, particularly if gas end-use efficiency options are considered. No direct data on natural gas supply infrastructure in San Francisco have been provided by PG&E.

Efficiency potential and savings

Just as natural gas demand consists of both direct and indirect consumption, efficiency initiatives also result in direct and indirect gas savings. However, because of the need to operate in-City generation for local reliability, most electricity efficiency measures allow the City to import less

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[12] Rick Brown, August 20, 2003. Manager of Gas and Transmission Planning, PG&E. Personal Communication
[13] California Energy Commission. 2000. *Application for Certification, Potrero Power Plant Unit 7 Project.* Sections 2.2.5.1 and 2.2.5.2. August.

power and increase transmission system reliability, rather than cause indirect gas savings in San Francisco.

Some efficiency measures such as building envelope improvements can reduce both electricity demand (space cooling) and natural gas demand (space heating). Other measures reduce natural gas directly, such as efficient gas furnaces, efficient water heaters, efficient gas cooking and laundry appliances, and insulating water heater tanks and water piping. There is also some potential for appliance fuel switching from electricity to gas, which would tend to negate some of the direct gas savings.

Natural gas efficiency potential analysis for the residential and commercial sectors specific to San Francisco was performed by Brown Vence and Associates (BVA) for 2001. We made adjustments to this analysis by using updated historical gas consumption data from PG&E.[14] Following the adjustments, we made new estimates of future gas savings for San Francisco. Data for the municipal efficiency potential were provided by the City of San Francisco.

The BVA estimates of economic energy-efficiency potential accumulate by about 180 billion Btu/year in the residential sector and about 100 billion Btu/year in the commercial sector. They also include an educational and marketing campaign that results in annual savings of about 340 billion Btu/year that persist over the long term. Total savings reach about 3.2 trillion Btu in 2012.

The BVA analysis also assumes efficiency measures in general (better controls, more efficient equipment, more insulation) but does not list specific gas efficiency measures (e.g., ceiling insulation from R5 to R24, boiler tune up, water tank insulation), and it is possible that not all cost-effective measures were considered. New construction was taken into consideration but the total savings include only 10% reduction in the annual increase in baseline gas demand.

Table 8 shows a comparison of the commercial sector efficiency potential estimates between the BVA analysis and the PG&E statewide efficiency potential estimates.[15]

Table 8. Comparison of commercial-sector natural gas efficiency potential estimates

End Use	Building Type	BVA SF economic 2001	PG&E economic 2003
Heating	Colleges	14%	16.2%
Heating	Food Stores	14%	18.2%
Heating	Hospitals	14%	17.3%
Heating	Hotel/Motel	14%	n.a.
Heating	Office	14%	31.5%
Heating	Miscellaneous	14%	18.1%
Heating	Restaurant	14%	n.a.

[14] PG&E. 2002. Response to energy data requested by San Francisco Public Utilities Commission: electricity (kWh) and gas (therms) for 1990-2001 by customer sector. June 26
[15] KEMA-Xenergy. 2003. California Statewide Commercial Sector Natural Gas Energy Efficiency Potential Study, Final Report. Vol. 2 of 2. Study ID#SW061. (prepared for PG&E). pp. G-2. May.

Heating	Retail	14%	19.8%
Heating	Schools	14%	1%
Heating	Warehouse	14%	15.8%
Water Heating	Colleges	11%	15%
Water Heating	Food Stores	11%	17.6%
Water Heating	Hospitals	11%	41.3%
Water Heating	Hotel/Motel	11%	20.3%
Water Heating	Office	11%	18.9%
Water Heating	Miscellaneous	11%	36.2%
Water Heating	Restaurant	11%	17.7%
Water Heating	Retail	11%	15.7%
Water Heating	Schools	11%	8%
Water Heating	Warehouse	11%	8.7%
Cooking	Hospitals	n.a.	15%
Cooking	Hotel/Motel	n.a.	15.4%
Cooking	Restaurant	n.a.	20.6%
Cooling	Colleges	14%	n.a.
Cooling	Food Stores	14%	n.a.
Cooling	Hospitals	14%	n.a.
Cooling	Hotel/Motel	14%	n.a.
Cooling	Large office	14%	n.a.
Cooling	Miscellaneous	14%	n.a.
Cooling	Restaurant	14%	n.a.
Cooling	Retail	14%	n.a.
Cooling	Schools	14%	n.a.
Cooling	Small office	14%	n.a.
Cooling	Warehouse	14%	n.a.
Commercial Miscellaneous	Colleges	7%	n.a.
Commercial Miscellaneous	Food Stores	7%	n.a.
Commercial Miscellaneous	Hospitals	7%	n.a.
Commercial Miscellaneous	Hotel/Motel	7%	n.a.
Commercial Miscellaneous	Large office	7%	n.a.
Commercial Miscellaneous	Miscellaneous	7%	n.a.
Commercial Miscellaneous	Restaurant	7%	n.a.
Commercial Miscellaneous	Retail	7%	n.a.
Commercial Miscellaneous	Schools	7%	n.a.
Commercial Miscellaneous	Small office	7%	n.a.
Commercial Miscellaneous	Warehouse	7%	n.a.

The first observation of Table 8 is that most of PG&E's efficiency potentials are higher than the BVA estimates. The second observation is that within each end use category, PG&E efficiency potentials differ markedly by building type, while BVA assumed that savings potentials are the same for each building type. Using PG&E's assumptions for economic potential where available in the BVA model, natural gas savings potential for the commercial sector in San Francisco doubles to 140 billion Btu/year annual savings, which raises the total economic potential savings in 2012 to about 1800 billion Btu.[16]

For residential sector efficiency, the PG&E statewide economic potential survey is more conservative than the BVA study, as shown in Table 9. Both studies consider envelope insulation in their estimates of space heating efficiency potential. However, neither study considers possible efficiency gains in cooking, clothes drying, or pools and spas, which can make up 7% of the total gas consumption.

Table 9. Comparison of residential-sector natural gas efficiency potential estimates

	BVA SF economic 2001	PG&E economic 2003
Space heating	14%	8%*
Water heating	15%	10%*
Cooking	0%	0%
Clothes drying	0%	0%
Pools and Spas	0%	0%

*A weighted average between single family and multifamily units

[16] Includes "one time" savings such as education campaigns.

AN ENERGY VISION FOR SAN FRANCISCO IN 2020

Based on the City's analysis of its energy situation and future options, and on an extensive process to solicit public input, the following goals were identified in the Electricity Resource Plan to set priorities for energy planning in San Francisco:

- Maximize Energy Efficiency
- Develop Renewable Power
- Assure Reliable Power
- Support Affordable Electric Bills
- Reduce Air Pollution and Prevent Other Environmental Impacts
- Support Environmental Justice
- Develop the Local Economy
- Increase Local Control Over Energy Resources

In this section, we examine San Francisco's energy infrastructure assuming that the future has arrived and that the City's energy goals are being met. We suggest how San Francisco's energy infrastructure could look in 2020, as it works to create a clean, reliable energy portfolio that stimulates the local economy and enhances the quality of life for those who live and work in San Francisco. We offer a number of ideas on what the City has done to achieve its goals, which include some of the recommendations outlined in the Electricity Resource Plan.

First, we examine the electricity supply infrastructure in 2020, including the network of power plants and the transmission system. Next, we examine the net consumers of energy in buildings and transportation. Finally, we examine a scenario in 2020 where hydrogen fuel-cell vehicles contribute to the City's power supply and help offset their own as well as building energy use through vehicle-to-grid (V2G) generation.

Note that fulfilling the vision presented here will require the successful commercialization of technologies such as fuel cells that are still under development today. Therefore, it is not certain that these results can be achieved. In order to provide a robust plan for delivering energy services reliably to the future citizens and workforce of San Francisco, we have also analyzed alternative scenarios that do not depend on the success of these emerging technologies. The structure of all scenarios we considered, as well as the result of our analysis regarding their cost, performance and environmental impacts, is presented in detail in later sections of this document.

Power Production

In 2020, San Francisco will have achieved the goal of a clean, fuel diversified, distributed electricity portfolio. First the Hunters Point plant and then the Potrero plant have been retired from service, at which point much of the City's electricity supply was provided by four combustion turbines (CTs) installed in 2005 as part of the Electric Reliability Project, complemented by a suite of small-scale engines, microturbines, fuel cells, and renewable sources of electricity such as wind and solar. The City continues to own and operate its hydroelectric generation facilities in Hetch Hetchy.

The supply resources are supplemented by a comprehensive suite of demand-side management (DSM) programs for all city sectors. Savings from DSM make it possible to meet the City's energy service requirements as the economy grows without increasing the total consumption of energy resources significantly. Energy growth has been decoupled from economic growth.

With total energy demand under control and increasing availability of distributed generation sources, the next major step in the City's sustainable energy development is to retire or mothball the four CTs that were built in 2005. This represents the end of central, fossil fuel-fired power generation in the City. Many of the remaining distributed generation sources are still fueled by natural gas; however, these sources are relatively clean because of the efficiency of cogeneration and because they rely on technologies such as hydrogen fuel cells. Moreover, the City is implementing an increasing share of renewable power sources to provide new capacity.

San Francisco has comprehensive incentives for distributed (co-) generation and renewable energy. Incentives include renewable portfolio standards, accelerated permitting and tax credits for clean generation, bureaucratic priority and additional incentives for investors and owners of renewable energy and distributed generation. These incentives result in between 225 MW and 315 MW of capacity from distributed generation sources in the City alone, reducing the required imports from outside the City. The friendly business atmosphere draws renewable energy suppliers and manufacturers to the city. San Francisco helps bring renewable energy manufacturing and assembly to the City and facilitates an active local solar installation industry. As a result, local air pollution has been reduced 80-90 percent relative to 2002 levels.

The high percentage of small-scale, distributed generation including renewable source in the City has helped to alleviate some of the transmission constraints on the San Francisco Peninsula. Many of the most important transmission upgrades and projects, including the 115 kV cable upgrades at Hunters Point-Potero and San Mateo-Martin line #4, the Ravenswood transformer #2, as well as the Jefferson-to-Martin project, are complete. Distributed generation is located close to loads and wherever possible, where it can relieve local transmission and distribution constraints. Many onsite generators supply both base-load power and part of the building's thermal load, and some have the capability for islanding to enhance reliability in case of grid power outages.

The large amount of small scale, distributed generation in the city provides redundancy and resiliency to the power supply infrastructure, such that accidental or intentional attacks cause minimal impact to the local economy. In addition, businesses are drawn to the improved reliability of electricity service in the City, and San Francisco enjoys a lower vacancy rate in its commercial buildings.

As an additional measure to enhance power supply reliability and resilience, in case of a catastrophic failure of the main Peninsula transmission artery (caused by earthquakes, weather, or sabotage), power barges, or power plants on boats, are employed. During an extreme event, the power barges dock near the Potrero plant site, connect to the electric substation there, and feed electricity to the City via the existing transmission substation. Although many businesses in the City are able to supply their own power with onsite distributed generation, the power barges make up for some of the imports that cannot be supplied to the city due to the transmission failure. The power barges may utilize the natural gas fuel resources at the Potrero site or carry their own fuel on board. Because the power barges are idle most of the time, the city may opt to share the costs of maintaining them with other cities such as Los Angeles and Seattle for their emergency use as well.

Fuel Cells and Hydrogen

The extent to which costs of fuel cells and hydrogen production decline by 2020 is uncertain. Today, fuel cell technology is quite expensive, at $3500 to $4500 per kW. However, fuel cells' high efficiency (40%-60%) and clean, quiet generation make them attractive as distributed generators. As researchers continue to innovate and manufacturers drive down fuel cell costs, the adoption of fuel cell generation by 2020, based on significant reductions in capital costs, is likely. A 50-60% reduction in capital cost, for example, would begin to bring stationary fuel cells in line with some of today's engine and gas turbine technologies. If a significant cost reduction does occur, stationary fuel cells could supplement and even replace engines and gas turbines for onsite cogeneration. Residential scale fuel cells, also under development, could also be employed to power homes in the city, especially if development of fuel cell vehicles leads to cost breakthroughs in low-temperature fuel cell technology.

The other aspect of fuel cell economics is to realize the full value of the clean, reliable, distributed (co-) generation source that fuel cells uniquely provide.[17] In addition to base-load power and heat (or cooling) energy, fuel cells can provide premium reliability, negligible local emissions, grid support and capacity cost deferral, ancillary services, as well as planning flexibility based on small, modular scale. As electricity planning evolves to more fully capture and monetize these benefits, the capital cost barrier to fuel cells becomes easier to overcome.

Growth in fuel cell demand stimulates the market for hydrogen production. Today, 95 percent of hydrogen is produced through natural gas steam reforming, and the rest from electrolysis of water. Assuming fuel cell costs decline and their value increases, San Francisco develops a nascent hydrogen production infrastructure by 2020. The majority of the hydrogen production will be onsite, tied to stationary fuel cells. However, a small but growing portion of the production is from more centralized natural gas reforming stations or electrolysis plants using renewable electricity, with transmission via dedicated pipelines.

By 2020, an increasing percentage of hydrogen production is from electrolysis of water, powered by renewable energy such as wind. Solar PV is needed most for reducing daytime demand rather than for hydrogen production. However, California windpower produces a significant quantity of energy at night, and San Francisco can import power for use in hydrogen production, as the nighttime market value is low and the city demand is low, freeing up transmission capacity.

[17] See Swisher, J., 2001. *Cleaner Energy, Greener Profits: Fuel Cells as Cost-Effective Distributed Generation Sources*, Rocky Mountain Institute, http://www.rmi.org/sitepages/pid171.php.

Buildings

By 2020, new construction will employ efficient technology for building systems and use less than half as much energy as today's buildings that comply with the Title 24 standards. Most buildings have been retrofitted for energy efficiency, and many are undergoing continuous commissioning or further retrofits as new efficient technologies enter the market. San Francisco has a vibrant buildings industry, with architects, engineers, builders, contractors and owners working together to advance efficient building design.

Annual green building award ceremonies sponsored by the city create an atmosphere of friendly competition where building industry members continually try to "one up" each other on the next efficient construction project. San Francisco has extensive contacts and relationships with the building industry members and its professional associations such as the Building Owners and Managers Association (BOMA). The City department provides a central resource and clearinghouse for building efficiency best practices and for state and local efficiency incentive program information.

The City also has developed contacts and relationships with manufacturers and retailers of energy-efficient building technologies for both builders and retail consumers. The City encourages and rewards manufacturers and retailers to sell efficient products to builders and consumers. Retailers are encouraged to retain at least half of their stock as energy efficient products, displayed with energy-efficient product labels. With this level of inventory, retailers are motivated to educate customers on the benefits of purchasing efficient products and promote the products with assistance from the City though product rebates and other incentives.

San Francisco's City departments convene multidisciplinary workshops and educational seminars in coordination with PG&E's program offerings. The workshops and seminars cover a wide range of topics on efficient building design, on systems such as lighting, HVAC, building electrical systems, and the building shell. The City also provides workshops informing retailers, builders, and consumers of current efficiency and distributed generation programs and incentives offered by the City, the State, and PG&E. Courses provide certification for contractors to install specified efficient equipment for PG&E or San Francisco prescriptive efficiency programs. A team of certified energy engineers works for the City to advise the building industry and homeowners on new building design and retrofit efficiency projects.

The City's efficiency programs have adopted a focus on whole building efficiency. These programs offer a combination of efficiency measures in a package, similar to weatherization packages for low income housing. For commercial facilities, whole building efficiency programs include facility commissioning to ensure that building systems and equipment operate according to design intent.

Similar efforts for efficiency in City-owned facilities are active and successful. City employees, in particular the operations and maintenance staff, facility managers, and engineers are trained in efficiency and energy management. City employees are encouraged to incorporate energy and environmental impact evaluation in project planning and implementation. Most of the City's energy intensive facilities have undergone energy retrofits, and San Francisco continues to sponsor demonstrations of fuel cell, energy storage, and renewable energy technologies.

The City works with PG&E and the State agencies to produce biannual energy studies of San Francisco's commercial and residential buildings. The studies include building surveys, energy use characteristics and appliance saturations, which assist the design of targeted electricity demand and energy consumption surveys. Altogether, these efficiency efforts produce approximately 140 MW – 240 MW of "negawatt" capacity for the City by 2020.

Transportation

San Francisco meets the California Air Resources Board (CARB) goal that one of every ten new vehicles purchased is a non-polluting vehicle, and a large number of clean, alternatively fueled vehicles are on the road by 2020. Many of the vehicles purchased are zero-emission electric and fuel cell vehicles. The city government leads by example, purchasing ultra-low emission and zero emission vehicles for its municipal fleet, and encourages citizens to do the same. The City continues to provide benefits for owners of non-polluting vehicles such as premium free parking downtown, discounts on bridge tolls, and HOV lane usage. These perks, combined with State and Federal tax incentives, make it economical to own electric and fuel cell vehicles in the city.

San Francisco's four existing natural gas vehicle-fueling stations have been upgraded to include steam reforming and possibly electrolysis for hydrogen production. Some fifteen City facilities are also equipped for battery vehicle charging for the City's vehicle fleets and for the public, and some of these also offer hydrogen. Federal and State incentives encourage businesses with distributed generation, especially fuel cells, to also install electric vehicle charging stations when their employees' vehicles are parked at work.

Fuel Cell Vehicles and Distributed Power Generation

If the cost of fuel cell vehicles (FCV) declines significantly by 2020, vehicle-to-grid (V2G) generation becomes possible. V2G is an attractive option for San Francisco because it supports the City's energy goals of providing clean alternatives to central, fossil-fired generation. V2G generation can enhance power service reliability to city customers and help stimulate the local renewable energy economy.

Vehicle to grid infrastructure in the city allows fuel cell vehicles to power the buildings where they park during the day. The generation output can shave a building's peak load during the day, leveling the building load shape and reducing demand charges and energy bills. San Francisco's on-peak daytime loads (10am – 7pm) exceed the off-peak loads by about 100 MW during the summer and by about 50 MW during the winter. Leveling this on-peak demand increment is an ideal target for V2G power, which can also provide ancillary services to the grid.

San Francisco implements any or all three scenarios for V2G: office park, public park, and city park, which are described in more detail in Appendix B.[18] The office park configuration allows employees of companies that have stationary fuel cells to drive their FCVs to work, park near the building and plug in. The vehicles receive hydrogen fuel from the building's natural gas steam

[18] Various investigations have explored residential V2G scenarios in which electric-based cars power homes and possibly the grid when parked at night. We do not include this approach in our scenarios, because it does not provide power when it is most needed and the difficulty of recovering the waste energy involved in fuel processing.

reformer and generate electricity during the workday. Because the on-peak loads extend into the early evening, such businesses as retail centers that remain open are perfect sites for V2G.

The public park configuration employs a few, large city parking structures to supply hydrogen to parked vehicles, sourced from steam reforming and/or off-peak nighttime electrolysis. Fuel cell vehicles then sell their power back to the grid at the highest price available from the quasi-real-time market. This implies the need for onboard computers that can log on to an electronic trading market during the day while the vehicles are unattended. FCVs park during the day and into the evening, providing power to the grid during on-peak hours.

The city park scenario provides grid connection stations at premier, reserved parking spaces around town. The cars supply power to the grid for only a few hours per day. No fuel is supplied to the cars; rather, owners are allowed to set how much power they will sell back to the grid while parked. Wireless communication with a car allows the ISO or a third party to control the vehicle's power output, up to the owner's limit.

Assuming that fuel cell vehicles can generate an average 10 kW for the grid,[19] 5000 vehicles employed for V2G produce 50 MW for the city. The vehicles belong to City fleets, City residents, and workers who commute to the City. The additional hardware to make fuel cell vehicles V2G-ready is rather simple, costing approximately $300 per vehicle for the DC-to-AC inverter and power management system, and another $200 per vehicle for adding a conducive socket, cables, plugs, fuses and communications equipment. Adding hydrogen fueling and the necessary safety equipment will add an additional $400 per vehicle,[20] for a total of about $900 per vehicle ($90/kW).

However, additional operating hours for power generation will increase the vehicular fuel cell replacement frequency relative to using the FCVs for mobility only. Estimates of fuel cell replacement costs vary widely, depending on the cost and longevity of fuel cells, but we assume a cost of about $30/MWh for fuel cell refurbishment, based on a fuel cell cost of about $200/kW and an operating life of 10,000 hours. The fuel cost for incremental hydrogen consumption is assumed to be $2/kg, which gives a total cost of V2G energy of about $130/MWh. These cost estimates are explained in more detail in Appendix B.

[19] At about 30% of maximum output, a 35-kW PEM fuel cell is at peak operational efficiency and operation and this output level mitigates the potential problem of a vehicular PEM fuel cell overheating while serving stationary loads.
[20] Kempton, Willet, et.al. 2001. Vehicle-to-Grid Power: Battery, Hybrid, and Fuel Cell Vehicles as Resources for Distributed Electric Power in California. Inst. of Transportation Studies, University of California, Davis.

ASSUMPTIONS ON ENERGY SYSTEM RESOURCES IN THE FUTURE

In order to analyze and prioritize the various energy resource options that will be available to San Francisco in the future, we need to clarify our quantitative assumptions regarding the present and future performance of these resources in the context of the San Francisco energy system.

Some of the most important assumptions, such as the rate of future growth in demand for energy services and the availability of certain key resources, have so much impact on the design of our resource portfolios that we have chosen to build separate future scenarios around the variations in these parameters. However, most of the relevant parameters conform to the following assumptions in all scenarios.

System Boundaries

For the City and County of San Francisco, political, geographic and electric system boundaries are key components of the scenarios (see Figure 16).

- Political boundaries can be perceived in widening circles, these include such communities of interest as the neighborhoods near the Hunters Point and Potrero power plants, and expand to the City boundaries. Beyond the City boundaries, the important jurisdiction is the State of California, which formulates much of the relevant energy legislation and utility regulations.

- Resource boundaries extend beyond the City limits to include such locations as the San Francisco International Airport (SFO), the potential wind farm sites in Alameda County, and the Hetch Hetchy complex of dams, pipelines and electric transmission lines.

- Electrical system boundaries are governed by the existing and future layout of the power generation, transmission and distribution infrastructure. At the end of a peninsula, San Francisco is isolated electrically from the rest of California, except for the transmission corridor that now connects the City to supply sources on the Peninsula. Beyond the Peninsula, the Hetch-Hechy hydropower production is transmitted to the Newark substation in southern Alameda County where this power, along with any new wind power, can reach the City only via PG&E's transmission grid.

Role of Electricity Resources in the Scenarios

Because the electrical boundaries are rather complex, our scenario analysis accounts for certain activities outside the political boundaries of the City and County of San Francisco. For example, City-owned facilities now generate electricity at Hetch-Hechy, and the potential wind turbine development would likely occur in Alameda County. The transfer, or "wheeling" of this power from the source to distribution substations in City is constrained by the same transmission limits that affect the import of power purchased from the grid.

This transmission constraint requires that our scenarios consider electric load growth and supply resources on the Peninsula north of San Mateo. This corridor along the Peninsula is relevant because it is the sole source of transmission capacity to San Francisco, and the limited transmission capacity must serve both the northern Peninsula and San Francisco load. Thus, increases in Peninsula loads reduce the amount of power that can be sent to San Francisco. On the other hand, energy savings via energy efficiency on the Peninsula, or certain generation sources such as SFO airport, make additional power available for the City.

Thus, three groups of resources can serve San Francisco's electricity service needs (Table 10):

- Resources that contribute to meeting reliability needs within the City and on the Peninsula north of San Mateo,
- Resources that can supply energy from outside this transmission-constrained area, and
- Resources that can both meet reliability needs and supply energy.

Table 10. Breakdown of the benefit of each type of electricity resource to San Francisco

Resources that meet reliability needs only	Resources that meet reliability needs and supply energy	Resources that supply energy only
▪ Transmission capacity into Martin substation ▪ Peak load management programs in CCSF	▪ Hunters Point Generation ▪ Potrero Generation ▪ New Peakers in CCSF ▪ New Cogeneration in CCSF ▪ Distributed Generation in CCSF ▪ Solar in CCSF ▪ Wind in CCSF ▪ Tidal in CCSF ▪ Energy Efficiency in CCSF ▪ Peninsula Generation ▪ Peninsula Energy Efficiency	▪ Hetch Hechy Hydro ▪ Wind in Alameda County ▪ Purchased Imports

Demand for Electricity Services in the Scenarios

The forecast of demand for electricity serves as the basis for planning the quantity and types of new resources that will be needed to assure reliability of electric service in San Francisco. New resources can include energy efficiency and load management programs that reduce demand, new in-City generation, and new transmission lines. Thus, the *baseline demand scenario* is the starting point in the analysis of supply resources and energy-efficiency improvements.

PG&E develops forecasts of future peak demand for the purpose of planning for grid reliability and for determining the need for additional transmission projects into San Francisco. These forecasts are published annually in PG&E's Electric Transmission Grid Expansion Plan.

For the purpose of the quantitative definition of the scenarios and resulting resource portfolios, one of the key variables is the rate of underlying energy demand growth. To explore this important uncertainty while keeping the analysis as simple as possible, we adopted two load growth scenarios, a high load vs. a low load case.

For the high load growth case, the California Energy Commission (CEC) 1-in-2 demand (MW) and consumption (GWh) forecasts for San Francisco were used. The data are located in the CEC's *California Energy Demand 2003-2013 Forecast* from February 2003. The 1-in-2 demand forecast was chosen to match the 1-in-2 consumption forecast, the only current consumption forecast available from the CEC. Demand and consumption forecasts beyond 2013 were estimated by calculating the average annual growth rate from 2003-2013. The observed 1.6% annual growth rate was applied to the demand from the prior year for each of the subsequent years beyond 2013. The overall load factor of 68%, calculated from the CEC consumption and *summer* peak demand forecasts, was applied to the baseline forecast for the future.[21] Also, a load factor, based on the *winter* peak, was calculated to be about 71%, and this was used to project winter peak loads as part of the future forecast.

Table 11. Summer Peak Demand Growth Scenario Projections, San Francisco (MW)

Year	CEC 1-in-2 Demand Forecast	PG&E 1-in-10 Demand Forecast
2003	917	900
2004	968	915
2005	992	927
2006	1004	942
2007	1022	955
2008	1045	968
2009	1062	978
2010	1082	989
2011	1099	998
2012	1116	1008
2013	1131	1018
2014	1149	1029
2015	1167	1041
2016	1186	1052
2017	1205	1064
2018	1224	1075
2019	1244	1087
2020	1264	1099

[21] A load factor measures the variability of the load. It is the ratio of the average load to the peak load during the same period. A load factor of 1.0 indicates a constant load, while a variable demand with a sharp peak has a low load factor. Load factor = average load (kW) / peak demand (kW)
= total energy use (kWh) / {peak demand (kW) * hours in period}

For the low load growth case, PG&E's 1-in-10 demand forecast for 2003-2013 was used.[22] Demand and consumption forecasts beyond 2013 were estimated by calculating the average annual growth rate from 2003-2013. The observed 1.1% annual growth rate was applied to each of the subsequent years beyond 2013. A corresponding consumption forecast was not available, but was calculated based on the 68% load factor (based on the summer peak) derived from the CEC forecasts used in the high load growth case. Similarly, the 71% winter load factor was used to project the winter peak loads. The resulting forecast values for the high and low load forecasts are shown in Figure 19, Table 11 and Table 12.

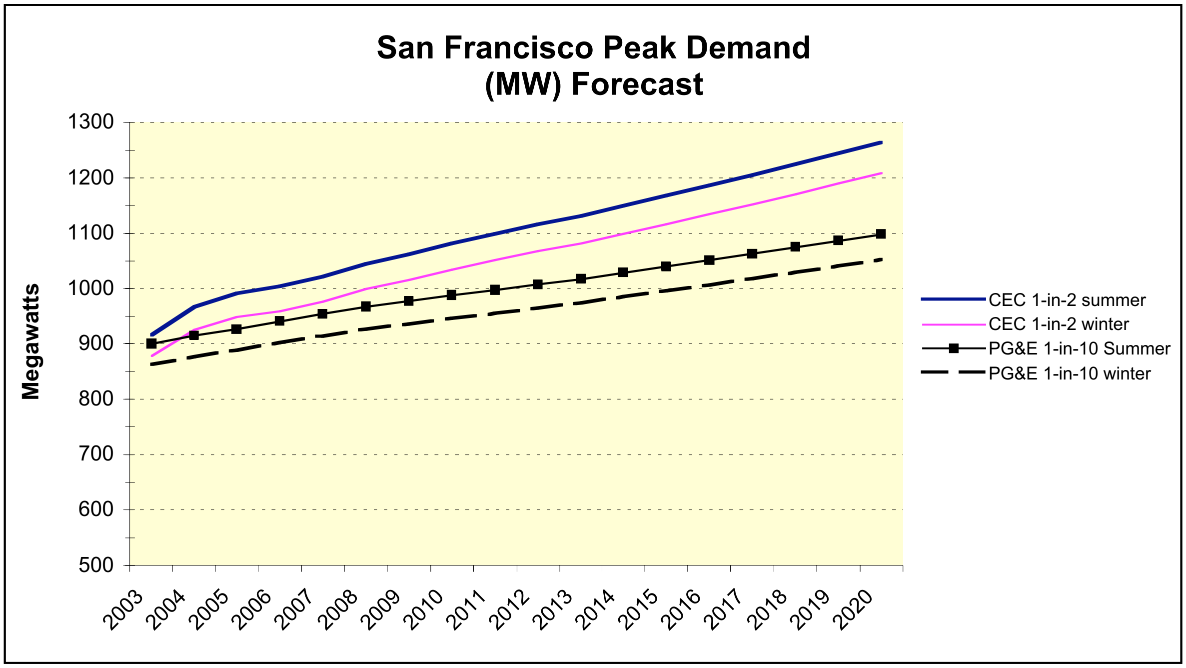
Table 12. Energy Consumption Growth Scenario Projections, San Francisco (GWh)

Year	CEC 1-in-2 Consumption Forecast	Consumption Based on PG&E 1-in-10 Demand Forecast
2003	5455	4730
2004	5761	4809
2005	5906	4872
2006	5973	4951
2007	6080	5019
2008	6220	5088
2009	6321	5140
2010	6437	5198
2011	6542	5245
2012	6642	5298
2013	6729	5351
2014	6837	5409
2015	6946	5469
2016	7057	5529
2017	7170	5590
2018	7285	5651
2019	7401	5714
2020	7520	5776

Given the geographical location of San Francisco at the end of a peninsula with transmission lines that serve the City coming from the south through one substation at the San Mateo-San Francisco County line, it is necessary to take into account demand for electricity in Northern San Mateo County in planning for new electricity resources. The forecasted demand for electricity in northern San Mateo County (north of the San Mateo substation is assumed to grow at the same rate as in San Francisco, i.e., 1.1%/year in the low load case and 1.6%/year in the high load case.

[22] Pacific Gas and Electric, *San Francisco Internal Transmission System After AP-1 Technical Study*, July 7, 2003.

Figure 19. Summer and Winter Peak Demand Growth Projections, San Francisco (MW)



Available Generation Capacity Assumptions

Generation resources include existing generation in San Francisco and technologies that the City can feasibly adopt in the future. Existing electricity resources available to San Francisco include: Hunters Point, Potrero, hydroelectric generation at Hetch Hetchy, SFPUC's power purchase contract with Calpine, and the 25 MW cogeneration plant at SFO airport.
We also include the 675 kW solar PV array on the Moscone Center roof and existing and planned energy efficiency programs.

Generation likely available to the City in the near to long term future include greater adoption of distributed generation resources, gas-fired micro- turbines and hydrogen fuel cells, and other renewable resources such as wind and solar PV.

The role of the supply resources in the scenarios is discussed further below. Cost assumptions on these resources are summarized in Table 13.

Resources serving summer vs. winter peak demand differently

Capacity assumptions and projections for the resource portfolios are classified according to those resources available to serve the summer peak and those resources available to serve the winter peak. Gas-fired generation such as Hunters Point and Potrero are assumed to serve the city year-round. Resources such as wind, solar PV, and Hetch Hetchy generation do not contribute equally to the summer and winter peaks.

Table 13: Assumptions on Costs, Efficiency and Capacity Factor for Electric Resources

	Capital Costs ($/kW)	Heat Rate (MMBtu / MWh)	Non-Fuel Energy Cost ($/MWh)[1]	Maximum Capacity Factor[2]
Potrero - Unit #3 retrofit[3]	184	10	20	10%
Existing peakers	0	12	20	10%
SF Williams cogeneration	950	7	8	90%
SF Williams peakers	800	10	8	30%
Cogeneration	1225	7	8	90%
Simple cycle gas	1075	10	8	30%
Combined cycle gas	600	10	19	60%
DG: gas ICEs w/CHP	1850	7	15	45%
DG: microturbines w/CHP	1800	7	15	45%
DG - high temp fuel cells[4]	3500	6	18	75%
DG - low temp fuel cells[4]	4500	6	20	45%
Solar PV in CCSF[4]	6000	N/A	6	19%
Hetch Hechy hydro upgrade[3]	1000	N/A	33	75%
Utility scale wind	900	N/A	13	32%
Small scale wind in CCSF	3000	N/A	6	29%
Biomass direct combustion	2500	14	10	70%

Notes: 1. Non-fuel operating costs include operation and maintenance, and transmission cost for resources outside the City. 2. Capacity factor is the ratio of the average power output to the rated capacity. 3. Cost of retrofit upgrades only. 4. DG capital costs decline at 2-5%/year for fuel cells and solar PV.

Solar PV is not productive to reduce winter peak demand in the City, because the winter peak occurs at nighttime. Therefore, solar PV is assumed to have zero contribution to winter peak capacity in the resource portfolios. Capacity additions through 2007 for City-sponsored solar PV projects are based on information provided by the City of San Francisco. To be conservative, private sector initiated projects are not included in the capacity plan through 2007. We assume that new government incentives for encouraging private sector solar projects will not be in place until then. As noted earlier, the City may not need more than about 30 MW of summer peaking capacity, due to the implementation of load management and demand response programs.

Hydroelectric generation produced by the Hetch Hetchy reservoir and owned by the City varies throughout the year. Generation peaks between February and June (wet season) and ebbs between July and January. Based on historical hydroelectricity generation data provided by the SFPUC, Hetch Hecthy generation contributes 120 MW of summer peak demand needs and 180MW of winter demand needs. This capacity increases to 130 MW and 195 MW, respectively, after 2006 when upgrades to the existing turbines are complete. While Hetch Hetchy power does not contribute to the load serving capacity within the transmission constraint on the San Francisco peninsula, it shelters the city against potential market price volatility by reducing the amount of power that the City needs to purchase from the power market to meet in-City loads.

In addition to its own generation, the *City purchases* approximately 55 MW of firm capacity from Calpine during July, August, and September (summer peak periods) and 40 MW of firm capacity during January, February, and March, when the city's winter peak can occur and when Hetch Hetchy has the highest hydroelectric generation capacity. The contract with Calpine ends in 2006. This power also does not contribute to the load serving capacity within the peninsula transmission constraint.

Resources serving summer and winter peak equally

All of the resource portfolios assume that Hunters Point retires in 2005. Actual service hours and energy generation data as reported to the CAISO in 2002 are used in all parameter (e.g. emissions) calculations.

The City's four existing 52 MW *oil-fired simple-cycle combustion turbines (peakers)* are used only to serve load during the City's peak periods. We assume that Hunters Point 1 is retired in 2005, while the remaining Potrero peakers are retained as backup to the new Williams turbines and during emergencies. For all portfolios, it is assumed that Potrero peakers continue to be available at least until the Jefferson-Martin transmission line is in service.

Because of their high emissions rate, the peakers are limited to run a maximum of 877 hour per year as defined by the Bay Area Air Quality Management District (BAAQMD). Actual 2002 service hours and energy generation data as reported to the CAISO are used in our parameter calculations through 2005. Service hours and energy generation are estimated for 2006 and beyond based on a simplified dispatch model that RMI created for this project in collaboration with the SFPUC.

Whether or not the steam turbine generation plant at *Potrero (unit 3)* is retrofitted with NOx emissions control is one of the short-term conditions in our scenario analysis. The CAISO and BAAQMD stipulate that the unit will be allowed to run at maximum load (207 MW) beyond 2005 only if it is retrofitted. Otherwise, Potrero unit 3 will only be permitted to run at minimum load (52 MW) beyond 2005 in order to satisfy BAAQMD regulations. The BAAQMD regulations were established in 1995 and require all units under the same ownership in the BAAQMD district to collectively meet the following maximum NOx emissions levels:

1/01/02	47 ppm (currently meeting this requirement)
1/01/04	31 ppm (a decrease of 1/3 compared to current levels)
1/01/05	15 ppm (a decrease of 2/3 compared to current levels)

As of this writing, it is more likely that the unit will be retrofitted than not, despite the bankruptcy of Mirant, the plant owner. If Potrero unit 3 is not retrofitted, we assume that it will run at minimum load only (52 MW) beginning in 2006.

Actual service hours and energy generation data as reported to the CAISO in 2002 are used in parameter calculations through 2005 for Potrero. Service hours and energy generation are estimated for 2006 and beyond based on a simplified dispatch model that RMI created for this project in collaboration with the SFPUC.

The City has obtained four *new gas-fired combustion turbine-generators* (GE LM 6000) through a legal settlement with the Williams Companies, Inc. One is planned to be installed in a co-generation configuration, where the cogeneration plant will be operated as a baseload plant. The new cogeneration installation is assumed to be located on the same site as the existing NRG 16-MW cogeneration facility. The new turbine is assumed to supplement the existing cogeneration capacity and also to displace one of the four older, less efficient boilers at the site.

The remaining three turbines will be installed in simple-cycle configuration and operated as peaking plants. All four turbines are assumed to be in service in 2005. Service hours and energy generation were estimated based on a simplified dispatch model that RMI created for this project in collaboration with the SFPUC.

Distributed generation in the resource portfolios relies on six technologies: internal combustion engines (ICEs), microturbines, high- and low-temperature fuel cells, distributed wind in the City, and solar PV in the City discussed above. The first microturbines and the first fuel cells are assumed to come on line beginning in 2005. Although fuel cells are still in their infancy in terms of commercialization, government incentives make it possible to bring the first fuel cell demonstration projects in the City on-line in the near future. Two fuel cell projects are currently being planned by the City, and another proposed demonstration project may be developed in the Presidio area as part of its infrastructure redevelopment.

ICEs and microturbines, on the other hand, are in commercial production. Almost 20 MW of privately-developed ICE capacity is already being planned in the City through 2005, in addition to several small projects planned by the City. Based on interviews with existing local energy service providers, we estimate that an annual capacity addition of up to 10 MW ICEs and microturbines is possible after 2005. In the longer term, the technology choice may shift to favor fuel cells, depending on local air quality regulations and especially on future progress in reducing the cost of stationary fuel cell generation technology.

The potential for *in-City wind* is small. Most of the wind potential lies east of the San Francisco peninsula and is best suited for utility scale development. However, some wind capacity, particularly small-scale wind generation, could be developed in the City over the long term. We estimate that up to 10MW of in-City installed wind capacity is ultimately feasible beyond 2015.

The potential is much greater for *wind outside the City*. Wind and other renewable resources development are driven by the California renewable portfolio standard[23] (RPS) and state incentives offered to achieve the goal of 20% renewable sources by 2017. California has several world-class wind sites, including some close to San Francisco such Altamont Pass (also one of the world's largest), Pacheco Pass, and Solano County, which sell power to PG&E.

New wind power resources will be available for import to the City from these sites or other possible sites in southern Alameda County. Wind power resources could be developed either by the City, possibly using funds from the proposition B revenue bonds, by private developers, or

[23] SB1078 signed by California governor Davis in 2002.

by a combination of public sector and private sector entities, including the City of San Francisco and PG&E.

The CEC projects 2,263 MW of wind added in the state by 2013, 37% of which (837 MW) will be connected at NP15 where San Francisco buys power[24]. We assume that a 50 MW wind project comes on line in 2007, and that about 100 MW of additional wind capacity can be added by 2013. San Francisco could easily exceed the 20% renewable share required by the RPS, enabling the City to sell excess renewable energy credits to other utilities.

Assumptions on Electricity Imports and Transmission Capacity

Import capacity determines how much generation is needed in the City. Thus, electricity transmission system resources must be included in the consideration of future energy services in San Francisco. Constraints on transmission capacity into the City limit the amount of power that can be imported from generation sources outside the City, including San Francisco's own sources at Hetch Hechy.

Based on the latest California Independent System Operator (CAISO) report on load serving capability for San Francisco and the peninsula (June 2003),[25] existing import capacity into San Francisco is currently 619 MW if existing in-City generators (or replacement capacity) are on-line and about 590MW if the in-City generation is off-line. This study indicates that there are several Bay Area transmission bottlenecks that affect supply reliability in San Francisco. One bottleneck is located on the Peninsula and limits the amount of electricity that can be delivered to the Martin substation in Brisbane, the City's primary transmission substation. A second bottleneck is the 115 kV transmission system within San Francisco and limits the ability to reliably import power into the City. A third potential bottleneck between the Tesla and Newark substations can also limit the amount of electricity that can be imported into the Bay Area.

Table 14. Near term transmission projects to serve San Francisco

Project Description	Project Status
Ravenswood 230/115 kV Transformer #2 (May 2004)	In planning phase, approved by PG&E
Hunters Point-Potrero (AP-1) 115 kV Cable (May 2004)	In detailed scoping phase, has not obtained PG&E approval, PG&E is working with the City and County of San Francisco
San Mateo-Martin 60-115 kV Line Conversion (Dec 2004)	In detailed scoping phase, PG&E has obtained approval to begin permitting process

[24] Vidaver, D. CEC Electricity Analysis Office *Preliminary Electricity and Natural Gas Infrastructure Assumptions*. IEPR Workshop on Staff's Draft report. February 26, 2003
[25] Arora, S., et al., *San Francisco Peninsula Load Serving Capability*, California ISO, June 2003.

To ensure that import transmission capacity is adequate to meet San Francisco's energy planning objectives, the City has been pressing the CAISO and PG&E to focus on transmission upgrades to improve reliability in the absence of the Hunters Point plant and eventually the Potrero plant. Several transmission projects are now being undertaken. These include line re-conductoring, line re-rating and equipment upgrades. The most significant of these are shown in Table 14.

These projects are assumed to be completed on schedule, and they will relieve to some degree all three bottlenecks that limit power imports to San Francisco. When completed, these projects will add up to about 100 MW of additional import capacity, depending somewhat on which generation sources are on line. This capacity will help reduce somewhat the need for in-City generation, which is the other supply-side option that is capable of overcoming all three of the transmission bottlenecks.

Of the other major transmission projects for the San Francisco Peninsula area that are in the planning or permit stages, improvements to the 115 kV transmission network in San Francisco and the new 230-kV transmission line between PG&E's Jefferson and Martin substations are the most important in terms of increasing the City's capacity to import power (see Table 15). The proposed Jefferson-Martin project will increase the transmission capacity of the Peninsula corridor, increasing the load serving capability at the Martin substation, which supplies the City. Although the project is currently scheduled for operation in 2005, it is unclear when it will actually be completed, and our scenarios allow for the possibility that it is delayed significantly.

Table 15. Long term transmission projects to serve San Francisco

Project Description	Project Status
Jefferson-Martin 230 kV Cable (September 2005)	Environmental studies phase, approved by PG&E to begin State permitting process
Martin-Hunters Point (HP-3) or Martin-Mission (HX-1) 115 kV Cable (2010)	Feasibility evaluation and analysis underway by PG&E

PG&E's draft report on transmission load serving capacity on the Peninsula demonstrates the benefits of the Jefferson-Martin transmission line to San Francisco's electric reliability.[26] While the capacity of the new line would be on the order of 400 MW, it would only contribute about 120 MW of incremental import capacity when first put in service. The addition of a third line between Martin and Hunters Point, or 3.5 miles of new underground 115 kV line from the Martin substation north to intersect with the Mission-Hunters Point line, together with the Jefferson-Martin line, would provide additional import capacity of about 240 MW.[27] While these projects

[26] Pacific Gas and Electric, *San Francisco Internal Transmission System After AP-1 Technical Study*, July 7, 2003.
[27] *Ibid*, in which PG&E recommends completing the Martin-Mission line by splicing a new segment from Martin to the existing Hunters Point-Mission line. However, in *PG&E's 2003 Electric Transmission Grid Expansion Plan*, PG&E recommends that a third line between Martin and Hunters Point would be less costly and equally effective.

would relieve the in-City and Peninsula constraints, additional transmission works farther upstream may be required to relieve the third bottleneck. However, it appears that PG&E has plans for completion of these additional works.

The PG&E report concludes that if the Jefferson-Martin and Martin-Hunters Point (or Mission) projects are completed, and the ratings are increased on other in-City lines, then the four City-owned combustion turbines (CTs) sited north of Martin would provide sufficient capacity to allow the shutdown of all existing generation at both the Hunters Point and Potrero sites. While the initial role of the planned City-owned CTs will be to assure the shutdown of Hunters Point unit 4, the PG&E report implies that the combustion turbines can also be instrumental in shutting down the Potrero power plant once additional transmission projects are completed.

Assumptions on Distribution System Capacity

In San Francisco, the distribution system is also subject to congestion and the need for capacity expansion and resulting capital costs. An ongoing State-funded research project is beginning to explore the potential for cost savings in the San Francisco distribution system from the implementation of distributed resources. One of the areas on which this work is focusing is the Hunters Point Naval Shipyard and the energy needs resulting from its redevelopment.

It also seems reasonable to expect that the existing distribution system in the City will require substantial investments to maintain and upgrade capacity to meet future loads. To date, however, the City has not obtained sufficient data from PG&E to estimate these costs and opportunities for mitigating them. Moreover, PG&E's present position on the City's distribution capacity is that major new investments are not expected in the foreseeable future. Thus, we cannot attribute significant value to DG or DSM projects on the basis of potential distribution grid benefits. Therefore, needs for distribution works in San Francisco are modest and unlikely to result in major cost differences between areas in the City.

However, targeted DG and DSM can offset costs in the distribution system, providing economic benefit to the utility. By selectively targeting DG projects and targeted DSM programs in areas where the distribution capacity costs are relatively high, it is possible (but difficult in practice) to defer distribution capacity investments.[28] This could be a key strategy to implement distributed resources in San Francisco, but applying this strategy will have to wait until closer collaboration can be achieved between PG&E and City on distribution planning and cost analysis.

Thus, distribution capacity and costs were not considered in detail, but we recommend that this question should be revisited in the future to possibly identify where and when targeted DG and DSM could provide cost savings in the distribution system. At a minimum, new developments such as the redevelopment of the Hunters Point Naval Shipyard site, will demand distribution expansion, the cost of which could be reduced through targeted DG and DSM in such areas.

[28] Swisher, J.N. and R. Orans.1996. A New Utility DSM Strategy Using Intensive Campaigns Based on Area-Specific Costs. *Utilities Policy,* vol. 5, pp. 185-197.

Assumptions on Electricity Resources on the Peninsula

Because of the transmission capacity constraints north of San Mateo, electricity loads and supply resources on this part of the Peninsula influence the supply resources that are available in the City. Although the scenarios do not assume that the City of San Francisco influences energy planning in Peninsula communities, the SFO airport and its tenants are municipal electricity customers. There is presently a co-generation facility at SFO airport, which exports about 25 MW net to the Peninsula grid. Generation capacity at SFO makes additional import capacity available to the City, via 115 kV line #5 San Mateo-SFO-Martin. Also, it is possible, but not assumed, that aggressive programs to support energy efficiency and solar energy in the City will indirectly stimulate implementation of efficiency programs on the Peninsula as well.

General Assumptions for Economic Analysis

Nominal Dollars Convention Used

All economic calculations in our studies, such as portfolio costs in the scenario analyses and financial flows of various investors in the project-level analyses, are based on nominal dollars. An inflation rate of 1.5% was used based on the current projections of the U.S. Bureau of Labor Statistics.

Gas Price Projections

Variations in future gas prices will affect the relative economics of central and distributed generation sources, and they will contribute to the volatility of market prices for imported power that must be purchased. The forecast of the cost of natural gas that we used is a combination of NYMEX Futures prices and a long-term forecast from the CEC’s August 2003 Natural Gas Market Assessment report.

The current prices are based on PG&E's (as of October, 2003) prices for its customers. An estimate of the cost that PG&E pays for wholesale gas was calculated from the NYMEX Henry Hub spot price plus a markup to represent the cost of transporting the gas to PG&E's pipeline. The markup assumed for 2003 is $0.58/MMBtu ($0.12/MMBtu for gas conditioning and $0.46/MMBtu for pipeline transport), which is the value estimated by the CEC.

For the years between 2004 and 2009, the 2003 prices were adjusted according to NYMEX futures prices for natural gas during these years. Prices for the years after 2009 were taken from the CEC's forecast included in the report Natural Gas Market Assessment. Based on the NYMEX futures price for 2009, an average of the CEC's 'Baseline' and 'High' forecasts was used.

The transition from using NYMEX Futures data until 2009 to using CEC data in 2010 produces a relatively smooth forecast. We adjusted 2010 data to be the average of 2009 and 2011 data, so as to further smooth this transition.

By using the futures market prices, and selecting a long-term price forecast that is consistent with these prices, we have attempted to capture the gas market price risk in our scenario analysis. Futures prices tend to trade at a premium to most short-term price forecasts, and this difference can be explained as a "risk premium," which the buyer pays in order to lock in a certain price, rather than the voltatile spot market price, over time.[29] Accounting for this risk premium in our gas price forecast captures some of the price-hedging value of constant-price resources, such as energy efficiency and renewable sources, in the economic analysis of the ERIS portfolios.

The longer term forecast, which we use after futures prices are no longer available, also captures some of the long-term risk premium, in that it appears to be consistent with the futures market prices and because it is based on today's historically high prices. Since price forecasts tend to float up and down with current price levels, using the present forecast should capture much of the upside price risk, and this is supported by the forecast's consistency with futures prices.

Power Market Price Projections

Due to the abnormal power market conditions that existed in California in 2000-2001 and parts of 2002, spot market data in 1999 for the NP15 region in California were used instead to represent the expected variations in market prices for purchased electricity. These data were adjusted to account for inflation and to include the effect that the recent rise in natural gas prices has had on spot market power prices.

The 1999 peak and partial peak data were adjusted upward to better reflect what they would be today in 2003. The data were adjusted based on typical heat rates of plants operating during peak and partial peak periods and an observed increase in the cost of natural gas of $3/MMBtu between 1999 and 2003. Spot market prices during peak hours (as defined by PG&E) are assumed to reflect the cost of generating using relatively inefficient (about 12 MMBtu/MWh heat rate) simple cycle peaking units. Prices during partial peak hours are assumed to reflect the cost of generation using more efficient (about 7 MMBtu/MWh heat rate) combined-cycle units. Spot market prices during off peak hours are assumed to be driven by non-gas-fired generation such as coal, nuclear and hydro, and therefore were only adjusted for inflation (11% between 1999 and 2003).[30]

Discount rate assumptions

In our economic analysis of energy supply and demand-side resources for various scenarios, future capital costs are discounted at discount rates that correspond to the cost of capital for the likely investor. For investments made by PG&E, the discount rate was assumed to be 8%. This is also the utility discount rate used in the Xenergy report "California's Secret Energy Surplus," which we used as the basis for our economic assessment of commercial sector energy-efficiency retrofit options.

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[29] See Bolinger, M., R. Wiser, and W. Golove, 2003. "Accounting for Fuel Price Risk: Using Forward Natural Gas Prices Instead of Gas Price Forecasts to Compare Renewable to Natural Gas Fired Generartion," Lawrence Berkeley National Lab, http://eetd.lbl.gov/ea/EMS/reports/53587.pdf).

[30] Source: U.S. Bureau of Labor and Statistics, http://www.bls.gov/cpi/

For City investments, the SFPUC's discount rate was assumed to be equal to the rate at which municipal bonds, such as those approved under Propositions B and H, would be sold. This value was estimated to be 5% for tax-free applications and 6.5% for taxable applications.

For private sector investments, merchant discount rates were calculated assuming a 25% to 75% debt-to-equity ratio. Debt from a private bank was assumed to carry an interest rate of 8%. In some cases, we calculated the interest rate made based on the possibility that the City would make revenue from the sales of the Proposition H bonds available to merchants for energy efficiency or distributed generation projects. In these cases, the debt rate was assumed to be equal to the bond rates described above, plus a .25% overhead that the SFPUC would add for its costs. A 15% return on equity (ROE) and a tax rate of 42.24% (34% Federal and 8.24% State) were assumed for all merchant projects. Using the (pre-tax) formula for the weighted average cost of capital (WACC):

WACC = %debt*interest rate + %equity*ROE = (0.25)(interest rate) + (0.75)(0.15)

Using these assumptions, the WACC is 13.25% with private bank debt, 12.56% and 12.94% with tax-free and taxable City Bond funds, respectively.

RESOURCE OPTIONS

The ERIS portfolios that follow are built from the following menu of energy resource options, which summarizes the range of technologies and programs we have considered as part of the ERIS. Based on a full menu of supply and demand-side options, we can design an ERIS that minimizes the overall cost of meeting demand for energy services and satisfies other local criteria such as environmental quality and justice, local economic development, etc. These options are further analyzed, prioritized and designed into a set of recommended portfolios for implementation in the remainder of this report on the ERIS work with the City of San Francisco.

Demand-side management (DSM)

One of the fundamental elements in the Energy Resource Investment Strategy (ERIS) is the treatment of demand-side management (DSM), including energy efficiency and peak load management measures, as resource options that are comparable in quantity and quality to traditional and alternative power supply technologies. Improved *energy efficiency* is the most important long-term DSM resource, because it provides both capacity and energy savings. Also, *peak load management*, which shifts electric usage away from times of high demand, can help relieve the City's supply capacity constraints, especially in the short term.

Peak load management

The capacity requirements for electricity generation, transmission and distribution are driven, not by the total consumption of electricity, but by the maximum instantaneous demand level. Power supply capacity and overall reliability in San Francisco and the Northern Peninsula are limited by the transmission capacity that provides imported power into the City, including power generated from the City's own resources at Hetch Hetchy or future wind farms.

Thus, managing electric loads to limit the peak demand can reduce power supply costs and contribute to the reliability of the power system in the City. Peak load management is often a positive side effect of end use efficiency improvements realized during times of peak demand, and indeed the energy efficiency potential we have identified could also cut the City's peak demand by more than 200 MW, but there are also separate options for peak load management apart from general efficiency improvement. Analyzing and designing load management options requires an understanding San Francisco's unique load profile, which determines when summer and winter peaks occur and which end-uses are the primary causes of the peaks.

Our analysis suggests that about 20-30 MW (which corresponds to 3-5% of commercial peak demand and 2-3% of City peak demand) can be removed from the summer peak using load management and demand response strategies that are feasible and cost-effective. These measures can also reduce the winter evening peak by about 8-10 MW, or about 1% of the total City winter peak. Because load management has a greater impact on the summer peak by design, it tends to reduce the difference between the summer and winter peaks.

In addition to peak-coincident energy efficiency improvements focused on lighting and HVAC, peak load management can be achieved through a combination of technology measures and program options. The *technologies* include:

- Demand-response controls to respond to real-time or critical-peak pricing
- Thermal energy storage (nighttime chilled water or ice making)
- Direct load control on residential water heaters

Programs to implement peak load management include the following:

- Demand response programs that combine advanced metering and control technology in buildings with dynamic or real-time pricing from the retail utility, in order to shave loads during times of peak demand with high reliability and minimal customer comfort impact.
- Direct load control of water heaters via utility line carrier, radio or cellular communication.

Electric end-use efficiency

Improving end-use energy efficiency is essential to making San Francisco's energy future more sustainable. While peak load management is a key short-term strategy that will help close the Hunters Point power plant while maintaining reliable electric service, improving the energy efficiency of all loads is the most cost-effective way to reduce emissions while providing the energy services the City needs for economic growth.

An interim goal, which is implicit in the Electricity Resource Plan compiled by two City departments in 2002, is to capture enough energy savings by mid-decade to mitigate incremental load growth. In other words, the goal is to use energy efficiency to meet all future growth in the demand for energy services in San Francisco. This goal corresponds to incremental annual savings of about 50-60 GWh (or about 10 MW of peak demand) from energy efficiency investments each year in our low demand-growth scenarios and about 100-120 GWh (or about 20 MW of peak demand) each year in our high demand-growth scenarios.

Retrofit energy-efficiency options

The energy efficiency of existing buildings depends on the age of the building and whether it has received energy efficiency retrofits recently, under PG&E or State-funded programs or under the independent direction of the building owner. Buildings constructed in recent years tend to be more energy efficient, because they were subject to the State of California's Title-24 energy efficiency standards when they were built.

As a result of these standards and the efficiency programs already conducted in the City to date, the future efficiency potential is reduced somewhat, and more advanced measures may be needed to further improve efficiency. This is one reason, in addition to the mild climate that limits savings from heating and cooling measures, that San Francisco's energy efficiency potential tends to be relatively expensive in terms of cost per saved kW or kWh.

As explained further in the methodology discussion under *Energy Resource Evaluation and Ranking*, much of our efficiency potential and cost estimates for building retrofits is adapted from work by Xenergy, Inc.[31] This analysis covers available efficiency potential in lighting, air conditioning, ventilation, refrigeration and office equipment in the following categories of commercial buildings:

- Office Buildings
- Restaurants
- Retail Stores
- Schools
- Warehouses
- Colleges
- Food Stores
- Hospitals
- Hotels and Motels
- Miscellaneous

The types of energy efficiency measures considered for existing commercial buildings include:

- Lighting: Retrofits to lighting systems that have not been updated in the last ten years. Opportunities for existing fluorescent fixtures include electronic ballasts, T8 lamps, specular reflectors (which allow de-lamping), timers and occupancy sensors in intermittently occupied spaces. Other opportunities include efficient security lighting in stairwells, exit signs, and exterior nighttime security lighting.
- Ventilation, cooling and refrigeration: Improving mechanical system efficiency through more efficient chillers and rooftop units, better cooling towers, control upgrades including variable-air-volume and economizer controls, right-sizing and variable-speed motor drives for pumps and fans.
- Office Equipment: Energy Star certified computers, monitors, copiers, and other types of equipment.

Efficiency opportunities in municipal facilities are similar to those in commercial buildings, because the majority of municipal energy use is in buildings, such as offices, hospitals and SFO airport, which are rather similar in their energy performance to those in the commercial sector. Some additional opportunities in municipal facilities include:

- Complete the replacement of conventional traffic lights with light-emitting diode (LED) technology.
- Efficiency retrofits in wastewater treatment plants to optimize separation efficiency, digester performance, and energy efficiency to improve effluent quality, reduce overflows, increase co-generation output, and reduce the energy use and peak demand of the facilities.
- Energy storage and efficiency retrofits in the Muni electric transportation system, including upgraded wiring on Muni trams and possibly install regenerative braking tied to energy storage units to reduce peak power demands.

Another important type of efficiency measure that we added to the potential estimates is retro-commissioning and commissioning. Commissioning involves the proper tuning and adjustment of various building systems, based on instrumented building performance diagnostic testing. Commissioning ensures that building HVAC, control, and electrical systems are operating

[31] Rufo, M. and F. Coito. *California Commercial Sector Energy Efficiency Potential Study (ID#SW039A)*. Pacific Gas and Electric Company. July, 9 2002

properly, based on comparison of actual operation and maintenance procedures to the intended or design procedures, using short-term or continuous diagnostic testing to detect problems. It often requires only minimal capital investment and achieves significant energy-efficiency and performance improvement with simple payback times of 1.5 years or less (see descriptions of Portland and Southern California Edison's commissioning programs in Appendix C). We estimate the economic potential savings for this measure as 20% of commercial and municipal HVAC energy, or about 240 GWh/year, and the achievable potential as about 110 GWh/year at a cost of $40/MWh saved.

We also consider the potential for retrofitting existing residential buildings, as the existing stock of residential buildings is generally inefficient in terms of energy use. This sector has not received as much energy-efficiency investment as the commercial sector, due to the difficulty and cost of marketing and implementation in the residential sector. In addition, a significant amount of residential energy use, both natural gas and electricity, is for space heating, and many City residences rely on individual room heaters rather than central furnaces. Retrofit efficiency measures to improve such heating equipment, or to improve the building shell, tend to be expensive and have a long payback in a mild climate such as San Francisco's.

Efficiency measures for existing residential buildings include the following:

- Appliances: New appliances that meet or exceed existing efficiency standards for refrigerators, dishwashers, and laundry appliances.
- Lighting: Adoption of efficient compact fluorescent lamps, and replacement of conventional torchieres (a dangerous fire hazard!) with fluorescent torchieres.

An additional (mostly residential) measure that we considered is efficient LED holiday lights, a relatively new innovation with potential benefits for winter-peaking utility systems (or that, like San Francisco, are nearly so). These lights use 90-98% less energy than standard and miniature incandescent holiday lights, and each string of lights is estimated to save about 45 watts at a cost (in volume) of about $8, or $180/kW. Because holiday lights are used few hours per year, this is an expensive efficiency measure (about $140/MWh), but a cost-effective winter peak load management option. We estimate the City's winter peak holiday lighting load to be about 20-25 MW, based on the observation that December peak loads exceed January peaks by about 27 MW even though January is typically colder, and the achievable savings to be 10 MW.[32]

Energy-efficient new construction

New buildings are subject to the State of California's Title-24 energy efficiency standards, making their baseline energy efficiency better than that of older buildings. However, it can be cost effective to exceed these standards in new buildings with an integrated green design approach that lowers operating costs. It is less costly to design an efficient building from the

[32] We assume that LED strings replace 90% mini light strings (saving 24 W) and 10% standards light strings (saving 220 W), and that lights are used 168 hours/year (6 hours/day for 28 days/year). 27 MW of lights correspond to 300 watts per single-family household, 80 watts per household of any size, or less if commercial holiday lighting is also included. Baseline research by BC Hydro found an average of 300 W for all dwellings. Other usage assumptions are also based on BC Hydro Power Smart data, (*Holiday Lighting Market Assessment*, August 2003), and performance data are from http://www.brite-lite.com/Products/LEDchristmas.htm.

beginning than it is to retrofit an existing one. Thus, this "lost opportunity" potential should be exploited as much as possible. Many of the opportunities listed above for existing buildings are also applicable in new construction, including solar energy and efficient lighting and appliances. However, there are also measures that are specific to new construction.

Much of the demand growth from new construction will be in the form of block loads, i.e., a small number of large, concentrated commercial and residential building projects that are expected in the next ten years. The high demand-growth scenarios assume these projects are completed in the next ten years, and that a similar rate of growth continues thereafter. In the low demand-growth scenarios, the timetable for these projects is slowed, and they are not completed until almost 2020.

New building projects include the residential redevelopment of the Mission Bay area and the commercial facilities associated with it. Other areas, such as the former Hunters Point Naval shipyard, will be redeveloped for residential, commercial and light-industrial use. Several other projects are in the planning stages for downtown and South-of-Market sites. These projects, summarized in Table 16, would use about 650 GWh annually and create a summer peak demand of about 130 MW.

Table 16. Estimated energy demand of new building development projects in San Francisco

	Electric use (GWh/year)		Peak demand (MW)	
Project	commercial	residential	summer	winter
Piers 27-31	15	-	3	2
Pier 38	10	-	2	2
Embarcadero hotel	5	-	1	1
Mission Street tower	25	-	6	4
SF cruise ship terminal	15	5	3	2
Transbay terminal	30	25	10	9
Hunters Point shipyard	160	35	40	30
Mission Bay waterfront	200	45	50	38
Bayview Hunters Point	55	25	15	12
Total	515	135	130	100

Source: RMI estimates based on development size estimates from SFPUC

These developments offer an opportunity for the City to partner with the developers and designers and to encourage energy-efficient and environmentally sound materials, technologies and designs that will help relieve the future burden of new energy demand growth on the City's infrastructure. These developments could be positioned as a showcase for responsible green design and enhance their image.

As part of the new commercial development, high energy-intensity facilities such as data centers may be developed in the City, once the information and telecommunication industries recover from the present slowdown. There is a pressing need to optimize the electronics, switchgear, HVAC systems, and backup power delivery in these facilities to provide the needed reliability and power quality while reducing power demand and equipment capital costs. A recent RMI workshop that gathered national experts on data centers found that, compared to today's data centers, 60% reductions in energy use are possible through improved practices with existing designs, and 90% savings can be realized with more advanced designs.[33]

We estimate that installing efficiency measures in new construction can achieve 50% or greater energy consumption reductions given proper planning, design, and incentives. A preliminary analysis of energy options for the residential component of the Hunters Point Naval Shipyard redevelopment indicates that careful building shell design can eliminate the need for air conditioning. Also, efficient lighting and appliances, including the replacement of electric stoves and dryers by gas appliances, bring the total electricity savings to about 45% compared to the Title 24-compliant baseline. Gas use is about the same, and electric peak demand is reduced by more than 50% (or 100% with rooftop solar PV added).[34]

The total net cost of the efficiency measures (excluding solar) is about $2000, which corresponds to a $45/MWh cost of saved energy. Based on this example, we estimate that the achievable efficiency potential in new residential construction is about 60 GWh annually, 7 MW at the summer peak and 10 MW at the winter peak.

Energy efficiency opportunities specific to new buildings in the commercial sector include the following measures:

- Building shell improvements such as high-performance windows, reflective roofs and shading devices to reduce solar heat gain.
- Advanced daylighting design and controls and mechanical system integration to reduce cooling and ventilation loads.
- High-efficiency air conditioning units, cooling towers and variable-speed motors.
- Demand-controlled ventilation to save energy and improve indoor air quality.
- Special options for hotels, such as efficient laundry equipment, service hot water systems (heat recovery, heat pump, solar preheat), and master controls using room-key activation.

Based on experience with green development and building design nationally, we estimate that efficiency improvements of 40% are achievable in new commercial buildings.[35] Applying this estimate to the planned new developments listed above, and conservatively ignoring efficiency potential in other new City loads, the estimated savings amount to about 240 GWh/year at a cost of $45/MWh saved, as well as 53 MW at the summer peak and 35 MW at the winter peak.

Energy Efficiency Program Options

The reason that cost-effective efficiency opportunities exist is that institutional barriers and market distortions prevent building owners, tenants, and builders from making the necessary technology choices and investments. Efficiency programs are designed to overcome these barriers and accelerate investment in efficiency measures. There are several types of programs to

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[33] See Eubank, H., *et al*, 2003. *Design Recommendations for High Performance Data Centers*, Rocky Mountain Institute, http://www.rmi.org/store/p12details2424.php
[34] Performance estimates based on analysis conducted for the SFPUC by Consol Energy Consulting.
[35] See Rocky Mountain Institute, 2002. *Green Developments 2.0* CD-ROM, http://www.rmi.org/store/p12details959.php

address the potential for energy efficiency in buildings. Several of these are discussed in more detail under *Policy and Program Needs* and in Appendix C.

Programs Applicable to All Sectors:

- Audits and information: Information on energy-efficiency technologies is a necessary but rarely sufficient tool for increasing adoption. Energy audits are helpful to identify site-specific opportunities, but may be too expensive for smaller customers.
- Incentives and loans: Financial incentives range from low-interest and deferred-payment loans to subsidies and rebates for the purchase of energy efficient equipment. Loan programs have generally not been very successful, as relatively low numbers of customers are typically willing to take on debt in order to save energy. Rebate programs have been more successful, although these programs sometimes suffer from high administrative costs.
- LEED or other green certification for new buildings: The U.S. Green Buildings Council's LEED rating system provides a point system for measuring the sustainability of a building project, including energy, water, materials, air quality and other criteria.
- Innovative financing such as Pay-As-You-Save (PAYS) programs, which enables customers to finance efficiency improvements with repayments via their (reduced) utility bills.
- Equipment supplier/vendor programs: Some utilities have offered financial incentives to manufacturers of efficient equipment to reduce their prices instead of giving the incentives to customers. Others, such as BC Hydro's Power Smart program, have worked directly with vendors, providing incentives to stock the most efficient model in each size range.

Programs Specific to the Commercial and Municipal Sectors:

- Energy performance standard for new commercial buildings (beyond Title-24): A more aggressive standard can be imposed in areas such as lighting energy use, HVAC efficiency, and window performance, but designers should be given flexible compliance paths, rather than prescriptive standards.
- Training and certification for commercial and municipal building operators, in order to improve operating efficiency of large buildings.
- Building energy code training for building inspectors, to increase the enforcement of existing State and local energy efficiency codes in new construction.
- Financing efficiency projects via performance contracting: Energy service companies (ESCos) can provide efficiency measures on a turnkey basis and receive payment as a share of the energy cost savings achieved. Performance contracting provides a way for public agencies to use future energy savings to finance and purchase energy-saving equipment, installation, and maintenance services, without using their own capital budget.
- Programs, such as a City energy challenge, to motivate public employees to be more aware of energy waste and look for energy-efficiency opportunities.

Programs Specific to the Residential Sector

- Home Energy Rating System (HERS): At point of sale, houses are evaluated using a standard procedure to rank their energy efficiency compared to other houses of similar size, and to predict energy bills under average occupancy and operating conditions.
- Direct installation: Direct installation programs involve actual installation of equipment by a utility or City representative. They are more expensive but have the potential to be simpler and therefore more cost-effective than simple incentive (rebate) programs. Direct installation

programs avoid the problem of consumers' lack of information, and they are particularly attractive for difficult sectors such as for multifamily and low-income rental housing. Such programs have greater consumer participation rates than incentive programs. For example, more than 90% participation was achieved in residential retrofit programs in Hood River, Oregon in the mid-1980s.

Natural gas efficiency

End-use energy efficiency opportunities for natural gas-fired end-uses are similar in nature to those for electricity, but these opportunities are generally restricted to space heating and water heating in buildings. There may also be some potential in industrial process heating, but there are relatively few industrial customers in San Francisco.

Space heating and water heating efficiency in buildings can be improved to some degree by higher-efficiency heating equipment, but there is often greater potential for reducing the heating loads. Water heating loads can be reduced by water efficiency measures such as low-flow fixtures and appliances and solar hot-water preheating. Space heating loads can be reduced by tightening the building envelope beyond Title-24 standards for new buildings, and by retrofitting existing building shells to reduce heat losses.

Distributed Generation

Distributed generation (DG) is the production of electricity in small units near customers. It usually involves the cogeneration of thermal energy for heating and/or cooling from the waste heat produced by the power generation process. Cogeneration is usually necessary to make DG cost-effective, and it is one of the key advantages of DG compared to central, remote generation.

Other advantages have appeared as market conditions in the electric power industry changed during the last two decades. A thorough examination of the issue of scale in power generation observed that central steam-turbine generation plants stopped getting more efficient in the 1960s, stopped getting cheaper in the 1970s, stopped getting bigger in the 1980s, and stopped getting built in the 1990s.[36]

The benefits of distributed generation include several general categories:[37]

- Energy cost savings from avoided electric and thermal energy purchases
- Option values from small scale, modularity, short lead time and high flexibility
- Distribution capacity cost deferral if correctly sited in time and place
- Electrical engineering cost savings in losses and ancillary services
- Utility and customer reliability benefits, including premium-power service
- Environmental benefits from emission costs and siting advantages

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[36] See Lovins, *et al*, 2002. *Small is Profitable*, Rocky Mountain Institute, http://www.rmi.org/store/p12details2419.php

[37] Swisher, Joel, 2002. *Cleaner Energy, Greener Profits: Fuel Cells as Cost-Effective Distributed Generation Sources*, Rocky Mountain Institute, Institute, http://www.rmi.org/sitepages/pid171.php.

Distributed (co-) generation can play a key role in San Francisco's energy planning, because it provides an efficient power supply option that can be sited inside the Peninsula transmission constraint, and that can be expanded in modular increments to keep up with future demand growth or the retirement of other generation plants. If the potential for premium reliability and grid benefits from DG can be realized, DG is even more attractive.

One of the key limitations to DG in the City could be environmental emissions. Although co-generation makes DG highly fuel efficient, the fact that it must be sited near residences and workplaces means that emissions must be very low for large amounts of DG to be acceptable. The emissions of present combustion technology are low enough to meet strict California emission standards in the short term. However, the widespread use of DG, as projected in our high-DG scenarios, requires that an even cleaner DG source such as fuel cells be employed.

Engines and turbines

Existing combustion technology is already making inroads into the DG market in San Francisco. Developers such as Real Energy and Northern Power are installing distributed co-generation units in large commercial buildings. These projects rely on natural gas-fired reciprocating engines as the prime mover. With state-of-the-art combustion and emission controls, these units are capable of meeting State emission standards for the foreseeable future. This technology is appropriate for systems with a scale of 200 kW or larger, which would typically be installed in buildings with a peak electric demand of at least 400-500 kW.

Smaller DG systems could be developed around the emerging microturbine technology. A microturbine is a small, simple-cycle turbine that runs on hydrocarbon fuels and spins at high speeds (on the order of 90,000 rpm). It has low NOx emissions compared to other small-scale combustion technologies. Microturbines produce about 30-60 kW each, and units with more than 100 kW are under development. Microturbines can be stacked to produce a modular system of the desired size. Modularity makes repair easier, downtime shorter, and reliability higher (if one turbine is out of commission, the rest can still run).

Fuel cell technologies

Fuel cells are electrochemical devices that convert hydrogen and oxygen to electricity and water at potentially very high efficiencies. Hydrogen can be made from steam reformation of natural gas or electrolysis of water using electricity. Although the hydrogen production may emit CO_2, fuel cells produce no significant local or greenhouse gas emissions in operation. The only major by-product is ultra-pure hot water.

The major difference between the four fuel cell types on the market and under development for stationary applications is the type of catalyst used to accelerate the reaction. Loose divisions can be made based on the fuel cell's operating temperature. Low temperature fuel cells include proton exchange membrane fuel cells (PEMFC) and phosphoric acid fuel cells (PAFC). High temperature fuel cells include molten carbonate fuel cells (MCFC) and solid oxide fuel cells (see Table 17).

Table 17. Fuel Cell Technologies under Development and Commercialization

Fuel Cell Technology	Electrolyte	Operating Temperature	Efficiency	Fuel Requirement
PEM (proton-exchange membrane)	Polymer	75 C (180ºF)	35-60%	Pure hydrogen or methanol. Natural gas requires a fuel reformer.
PA (phosphoric acid)	Phosphoric acid	210 C (400ºF)	35-50%	Hydrogen, but not as pure as PEM. (Natural gas requires fuel conversion.)
MC (molten carbonate)	Molten carbonate salt	650 C (1200ºF)	40-55%	Hydrogen, natural gas (integrated reformer)
SO (solid oxide)	Ceramic	800-1000 C (1500-1800ºF)	45-60%	Hydrogen, natural gas (no separate reformer)

In general, the higher temperature cells can tolerate greater impurities in the fuel, which makes reforming of hydrocarbon fuels simpler or unnecessary. Higher temperatures allow the MCFC and SOFC the possibility of taking advantage of heat recuperation using a combined-cycle steam turbine, which can increase generation efficiency by about 10%. In general, based on the exhaust temperature, PEMFCs and PAFCs can produce hot-water only using co-generation, while MCFCs and SPFCs can hybridize with turbines, and do full co- and tri-generation.

In terms of commercialization status, although PAFCs are the most proven technology, with over 200 units (each 200 kW) already installed worldwide, they are no longer being produced by United Technologies, their main manufacturer. Other fuel cells are expected to perform better than the PAFC, and some are already reaching the commercialization stage.

- PEMFCs are promising for vehicular applications, due to their potential load-following capability, and stationary units are expected in commercial applications by 2004.
- MCFCs are promising, and many commercial field sites are operational. They are ideal for baseload (constant) power production.
- SOFCs might be the best long-term solution for stationary power generation. Some demonstration units are operational, and commercialization is expected by 2004-2005.

Conventional fossil generation

Although the City's energy goals focus on the retirement of existing fossil fuel-fired generation and its eventual replacement by distributed and renewable sources, central, fossil generation still has an important role to play in the near term at least. The most reliable strategy for the City to replace the old, inefficient steam turbine plants at Hunters Point and Potrero Hill is to develop its own combustion turbine generation capacity for a combination of efficient co-generation and peaking capacity that can help mitigate the Peninsula transmission constraint.

Existing Steam Turbine Capacity

The planned closure of Hunters Point is likely to be accompanied by retrofit upgrades to the remaining steam turbine at Potrero (unit 3) to best-available control technology (BACT), using selective catalytic reduction (SCR) technology to reduce NOx emissions. The remaining Potrero power plant, including the three CTs at Potrero will be used primarily for system reliability and for peaking capacity as long as needed.

Conventional co-generation

Combustion turbine (CT) options for central and distributed co-generation range between 4 and 50 MW (electric) in size. These turbines can be used to generate electricity and also to provide heating and cooling, with co- and tri-generation respectively.[38] There is presently a 25-MW co-generation facility at SFO airport. There are a number of potential sites for co-generation in San Francisco. Sites for small systems (<10 MW) are common wherever significant electric and thermal energy loads coincide. Sites for larger systems are less common, because of limited thermal loads. However, possible larger sites at the university hospital and in Mission Bay have been identified, and additional studies are under study.

One of the potential applications of the CTs that the City received from the Williams settlement (see below) is to install a CT at the downtown district steam system to co-generate electricity and make the district steam from the waste heat produced by the CT. This is typically an efficient use of energy, as the electricity and heat would otherwise have to be produced separately with additional fuel use. The efficiency and economics of a district heating co-generation plant depends on the efficiency of the heating loop. A new hot water loop could be 90% efficient, but an old steam system, such as San Francisco's, without condensate return would be more like 50-80% efficient. If it is only 50%, then the district heating co-generation system is no more efficient than replacing the district heating with high-efficiency individual boilers and using the waste heat from the CT for additional power generation in a combined-cycle configuration. This comparison is only in terms of energy (and CO_2 emissions), as more information is needed for a life-cycle cost comparison, but this tradeoff warrants further study.

New in-City peaking capacity – 50 MW simple cycle

In order to accommodate the closure of the Hunters Point power plant in 2005, San Francisco will need new generation capacity to meet peak demand in the 2005 timeframe. Depending on the rate at which economic activity and demand growth recovers, generation capacity will be needed to maintain supply reliability with the closure of Hunters Point. Therefore, new 50-MW in-City peaking units are likely to be needed. It is not yet clear where these units would be sited, but one candidate would be at the existing Potrero site.

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[38] *Co-generation* refers to the use of any waste heat for space- or water-heating. *Tri-generation* is the use of waste heat to drive an absorption chiller. Only waste heat at high enough temperatures can be used for tri-generation, and gas turbines can provide this high quality waste heat. *Simple cycle* means that combusted fuel is run through the turbine and then exhausted at very high temperatures. *Combined-cycle* means that exhaust heat is used to heat water to run a steam turbine, thus increasing the efficiency of electricity production.

In late 2002, CCSF obtained four new gas-fired combustion turbine-generators (GE LM 6000) through a legal settlement with the Williams Companies, Inc, with a total capacity of about 190 MW (or more in combined-cycle configuration). The City will also receive $13.6 million from Williams to develop the generating facilities. To ensure the project's financial viability, the City negotiated a 10-year Power Purchase Agreement (PPA) with DWR that will provide sufficient revenues to repay municipal bond financing for the project. The PPA is structured so that capacity and power purchases cover the full capital and operating costs of the project.

The CA-ISO has committed to shutting down Hunters Point 4 if the new combustion turbines are installed on the 115 kV system north of the Martin substation and some transmission system upgrades are completed. Those transmission projects do not include the proposed 230 kV Jefferson-Martin transmission line and related projects such as the line from Martin to Hunters Point or Mission.

After ten years, San Francisco will have full ownership of the four turbines. San Francisco will have additional generation capacity to complement its hydroelectric assets to serve City loads and possibly other municipalities' energy needs. The City will still need to find a new market that will purchase the power from HHWP.

Peaking plants need to be able to start up quickly when needed, and therefore several of the turbines will likely be configured as simple-cycle gas turbines rather than combined-cycle turbines, which are better suited to constant, baseload operation. Co-generation is probably not a viable option for the peaking CTs, since the generators will run at unpredictable times and likely for less than 2000 hours per year. At least one of the four available turbines, however, could be configured for co-generation or combined-cycle operation as a baseload plant running at more than 6000 hours per year.

Multiple units of the same size ensure greater reliability of supply. If one unit is out of operation, the others can still run, and only a fraction of the total capacity is lost. Utility planning criteria (including those of the CAISO) are typically based on the load-serving capacity that remains with the largest generating unit out of operation. In the future, assuming that both Hunters Point and Potrero unit 3 are closed, the largest generating unit would then be a peaking unit of about 50 MW, and all other in-City generators would be considered as available load-serving capacity. If energy efficiency and load management programs are successful in keeping peak demand approximately level beyond about 2005, then these new peaking units might be the only central fossil generation that the City will need to build in the foreseeable future.

Combined-cycle generation at SFO airport

The airport is a promising location for a medium sized (60-100 MW) combined-cycle gas turbine generation plant. Because of its position relative to the transmission lines connecting the San Mateo and Martin substations on the Peninsula, generation at the airport can contribute to supply reliability in the City, even though it is not located within the City. Furthermore, fewer siting problems are anticipated because the airport already has significant environmental impacts from the aviation operations, and it is less sensitive environmentally than sites closer to the City or other Bay Area communities.

The possible development of a combined-cycle plant at SFO airport has been studied recently by the City, and the airport could be a possible site for the CTs from the Williams settlement. However, grid interconnection for a new plant of this scale appears to be complex and expensive, and at present no proposed project is moving forward. Recent State of California projections of long-term energy supply indicate the potential need for generation capacity on the Peninsula. If this need materializes, the option of generation at SFO could be revisited, but we do not include this as a resource in our scenarios for the City of San Francisco.

Renewable power generation

Emission-free renewable power sources are highly valued in San Francisco. Indeed, in the November 2001 election, the passage of Propositions B and H called for the issuance of revenue bonds for renewable energy and energy efficiency in municipal facilities and the private sector.

Due to variations in the renewable resource base, the potential for renewable sources is highly site-specific. The best opportunities for low-cost renewable power, mostly from wind and hydropower, are mostly located outside the City, where power must be wheeled to the City via PG&E's grid through the constrained Peninsula transmission corridor. As a result, there is a premium on renewable sources, such as solar PV, that can be sited in the City, because these sources can contribute directly to supply reliability.

Advanced hydro

Advanced hydro is the use of modern, advanced turbines in hydroelectric dams and run-of-the-river generation facilities. Advanced hydro turbines decrease fish mortality, last longer with less maintenance and generate more electricity from the same water flow compared to older turbines. Upgrades to existing plants are generally a profitable investment, and new plants utilizing advanced technology are more environmentally benign (some 98% of fish survive trips through these turbines)39. These turbines can also be installed into dams that currently have no hydroelectric generation capability.

Wind power

Commercial wind power is generated by tall, upright turbines, each with a diameter of 50-80 meters (170-270 feet) and a power rating of 500 kW-1.5 MW. These turbines are usually placed in large wind farms in areas with high wind resources and low population density. Alameda County has a good wind resource (class 5-6) and appears to be a promising site for a wind farm to augment San Francisco's generation from renewable sources.

Wind technology is currently economically and environmentally attractive, and the economics are especially favorable compared to other renewable sources. The main disadvantages are its intermittent output and its location: outside of the Peninsula transmission constraint. The

[39] tech_profiles.pdf, pg 47

attractive wind sites in Alameda County require that the power generated from the wind be wheeled through PG&E's transmission lines to the City, through the constrained transmission corridor on the Peninsula. In addition to imposing a cost for wheeling the power via the transmission grid, this transmission capacity can become saturated or even overloaded, reducing the ability of power sources that rely on this corridor to meet loads in the City.

We also considered the installation of smaller wind turbines (< 10 kW) on in-City shoreline property. This idea has several hurdles to overcome, though, such as permitting, acceptance by property owners, remediation of visual impact and definition of a good wind resource. Furthermore, the economics of such small-scale systems is considerably inferior to large systems. However, they would have the advantage of delivering renewable power inside of the Peninsula transmission constraint.

Solar photovoltaics

Photovoltaic (PV) panels convert solar radiation directly into electricity. These panels can be made of crystalline silicon, amorphous silicon, or other materials (thin film types). PV panels are generally installed on rooftops in arrays of several modules adjacent to each other. The City has recently completed the installation of a 675 kW PV system, covering about two acres of rooftop, on the Moscone Center.

Because solar PV is an expensive energy source, the intensity and timing of the solar resource is an important consideration in determining the value of PV capacity. The amount of energy produced on an annual basis depends on the solar capacity factor, which is the ratio of the average energy production to the PV output at full solar intensity (1017 W/m^2).

Because of the microclimatic variations in the City, some locations are relatively sunny and others are foggy and less attractive. The SFPUC is presently conducting solar monitoring studies to produce more detailed data, but it is clear that there is a strong solar gradient across San Francisco from west to east. The better solar sites will be found on the eastern side of the City, away from the ocean fog. We estimate that the solar capacity factor ranges from a low of about 15% to about 21% at the best sites. Although the best capacity factor observed from existing weather station data in the City indicates a value of 19.3%,[40] we assume that future solar PV installations will focus on the best sites with a capacity factor of 21%.

Timing of the solar resource is important to the ability of solar PV to contribute to meeting peak demand and relieving San Francisco's supply constraints. Ironically, contrary to the City's foggy reputation, solar can have a relatively high summer peak capacity value, specifically because of the mild climate. Unlike inland areas, San Francisco has little residential air conditioning, and the summer demand profile drops quickly in the late afternoon and evening as the commercial loads subside. Therefore, solar production that peaks in the early afternoon is relatively coincident with the City's afternoon peak. Based on comparison of the time profiles of the solar resource and PG&E's demand, we estimate that about 70% of maximum solar PV output would be coincident with the summer peak.

[40] These data are taken from http://www.californiasolarcenter.org/pdfs/SFPV.pdf, pp. 6-7.

Energy planning in San Francisco must also address the winter peak, which is presently only about 40-50 MW less than the summer peak on average. Because the winter peak occurs in the evening after dark, solar PV is of little value at that time. This means that the maximum capacity benefit from solar PV in the City is that which reduces the summer peak to the same level as the winter peak.

In the ERIS scenarios, our demand-side management (DSM) projections call for about 20 MW of summer peak demand reductions, in excess of winter peak reductions, form demand response and other DSM measures. Thus, we expect that the future summer peak will exceed the winter peak by only about 20-30 MW. This means that our future resource portfolios could benefit from no more than 20-30 MW of peak output from solar generation. This corresponds to a maximum solar capacity of 30-40 MW. Additional solar capacity would provide clean energy to the City, but it would be unlikely to contribute to relieving the City's supply constraints.

Tidal power

Tidal power or tidal current power in San Francisco Bay may provide power with a relatively high capacity factor inside the transmission constraint. Tidal power generating systems place turbines in flowing water (i.e. a tidal stream), which causes the turbines to rotate and produce electricity. All of the several tidal power technologies now under development are immature, and their future performance, cost-effectiveness, and environmental impact are uncertain.

However, there is great potential for fish-safe, zero-emissions electricity production from flowing water without the construction of heavy barges or dams. The turbines are simply anchored to a buoy or the ocean floor, usually within a mile of the shore, where they produce electricity. At present there are several conceptual approaches to tidal marine power under development. It is not clear which technology will be the best in the long-run, since they are all in similar stages of pre-commercial trials and development. One approach uses *vertical* axis turbines inside a box-type frame that can stack together on the sea bottom to form a tidal fence.

There is considerable progress being made in the development of tidal current power technology, which is similar to run-of-river hydropower and requires no impoundment of tidal flows. In 2003, this technology was successfully deployed using a prototype turbine system in the East River in New York City, and other demonstrations are underway, using a variety of turbine configurations.[41] Horizontal axis turbines are anchored to the river or sea bottom, and they are designed for underwater fields, consisting of multiple adjacent units. Another approach uses a vertical axis Gorlov turbine moored to a floating platform.

A key prerequisite for tidal power to provide useful energy to San Francisco is to find a strong match between the locations of adequate tidal energy resources and potential interconnections to PG&E's existing transmission system in San Francisco. There are strong currents in the Golden Gate, in the northern Bay and west of Treasure Island (see Figure 20). Although there are strong flows near the Golden Gate Bridge, for example, this site is too sensitive environmentally and its location is far from any cost-effective connection point.

[41] See, for example, www.verdantpower.com /Initiatives/eastriver.shtml

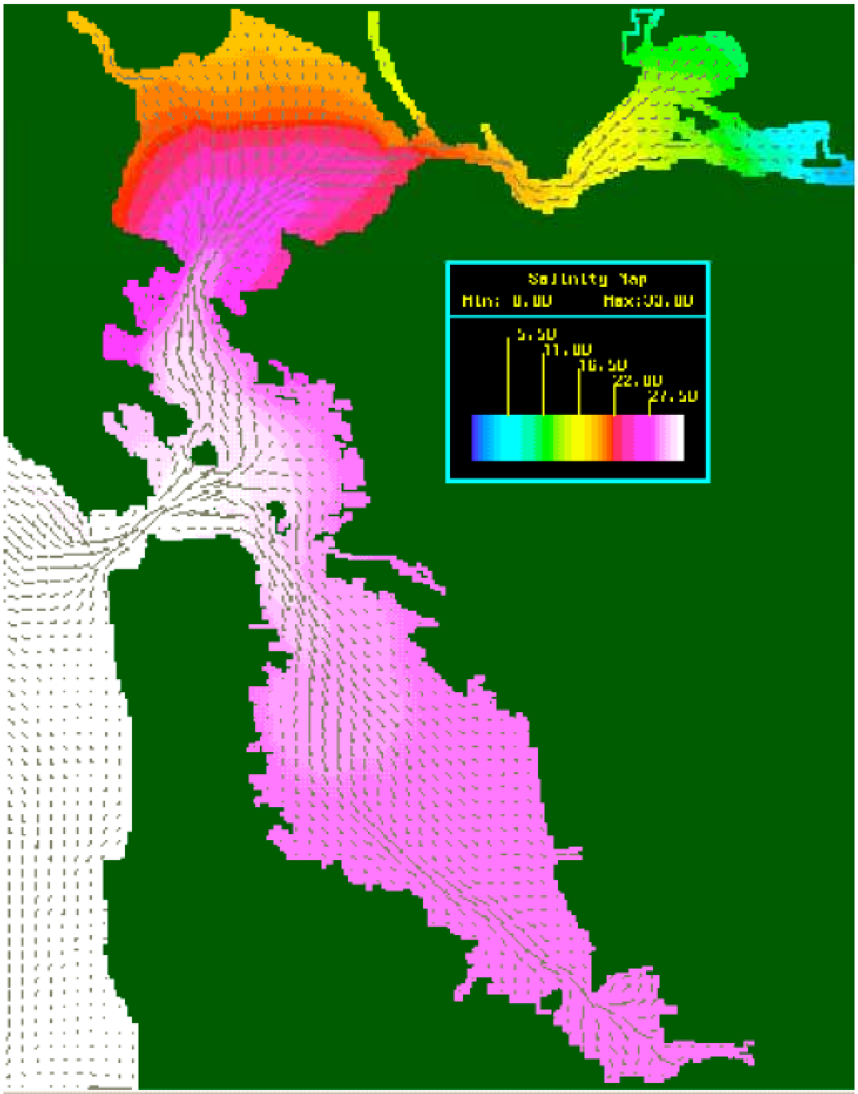

Figure 20. Distribution of tidal flows and salinity in San Francisco Bay.

Source: R.T. Cheng, U.S.G.S., http://sfbay.wr.usgs.gov/access/Cheng.html

Feasible interconnection points probably include the Potrero and Embarcadero substations, although the tidal resources and interconnection points might not be in close enough proximity. While sites near the Potrero power plant and substation would provide a convenient and probably cost effective connection point; however, it is unclear if the tidal current resource in this area of San Francisco Bay is adequate to produce cost-effective energy. It may be that the most feasible sites in the Bay Area are in Marin or Contra Costa County, which could provide clean energy but, like wind farms in Alameda County, would not contribute to the reliability of power supply within the Peninsula transmission constraint.

ENERGY RESOURCE EVALUATION AND RANKING

The Energy Resource Investment Strategy (ERIS) approach is a refinement of the methodology used for integrated resource planning (IRP), in which demand-side management (DSM) technologies such as energy efficiency improvements and distributed generation (DG) sources are considered as energy utility investments that can complement and compete with more conventional, centralized supply technologies in energy resource planning. The ERIS approach takes a locally-oriented, bottom-up approach, which is appropriate for addressing the situation in San Francisco.

The scenario analyses described in this report are based on a bottom-up approach to resource analysis.[42] The principal objective of bottom-up analysis is to create a quantitative description of the technological structure of energy conversion and use. It begins with one or more estimates of the demand for end-use energy services, and from this foundation builds future scenarios using different combinations of technologies for delivering energy supplies and/or limiting energy demand.

The basic outline of the Energy Resource Investment Strategy (ERIS) process involves:

- Data collection on end-use demand and technical options for energy efficiency and supply
- Definition and projection of energy-service demand scenarios
- Calculation of costs and load impacts of DSM and supply options under different scenarios
- Comparison of costs and environmental impacts of DSM and supply options in each scenario
- Assembly of an integrated strategy to minimize economic costs and environmental impacts
- Design of a financing and implementation plan for the selected strategy for each scenario

The resource options in each scenario must meet both the total energy demand (in MWh) and the maximum peak demand (in MW) in summer and winter. Peak demand can be met either by central electricity supply resources, via the generation and T&D systems, by distributed generation (DG) or co-generation sources, or by reducing peak demand, via energy efficiency and other demand-side management (DSM) programs. Because the transmission capacity into the City is limited, a portion of the peak electric demand must be met by in-City resources, in order to avoid violating the transmission constraint and compromising reliability.

The main criteria for evaluating and ranking future energy resource options for San Francisco are their costs, environmental impacts, and potential contributions to meeting future energy service needs. These contributions have several dimensions. First, the definition of the ERIS or IRP methods explicitly includes the treatment of energy efficiency and other DSM resources as comparable to supply resources. A kWh saved is just as useful in meeting customer energy needs as a kWh generated and delivered.

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[42] This approach follows the basic analytic methods used in integrated resource planning (IRP). See Swisher, J., G. Jannuzzi and R. Redlinger, 1997. *Tools and Methods for Integrated Resource Planning: Improving Energy Efficiency and Protecting the Environment*, UNEP Collaborating Centre on Energy and Environment, Denmark, http://www.uccee.org/IRPManual/index.htm. For an example of the application of IRP tools, see Northwest Power Planning Council (NWPPC), 1991. "Northwest Conservation and Electric Power Plan," NWPPC, Portland, Oregon.

Second, there are important time dynamics at work on both the supply and demand-side analysis of the energy system. Energy demand varies with time, and it is just as essential to ensure that there is enough capacity (kW), to meet peak demands in the summer and winter seasons, as to meet the total energy service demand (kWh) over the entire year. Therefore, we must pay careful attention to evaluating the ability of each resource option to produce or save energy (kWh), as well as to produce or save capacity (kW) during the summer peak and/or the winter peak periods. In San Francisco, these dynamics are quite complex, demanding special attention.

Thus, the key input to the process of creating resource portfolios under a range of scenarios is a quantitative evaluation, comparison and ranking of the resource options that could contribute to meeting San Francisco's energy services needs in the future. This evaluation, the results of which are expressed in the form of marginal cost rankings, or "integrated resource supply curves," shows the relative magnitude of each resource option (in terms of kWh of energy and kW of capacity) over time, as well as their relative performance (in terms of capital, operating, fuel and environmental costs).

The "integrated resource supply curves" presented below focus on the 2006-2013 time frame, for which we are able to perform relatively precise calculations on cost and performance. Much of this medium-term analysis also applies to the longer term, to 2020, but some additional resources will likely be available by that time. The cost and performance of newer technologies (hydrogen fuel cells, advanced solar photovoltaics, tidal current generation, etc.) are less certain, and our evaluation of their long-term potential is less precise.

Methodology for Determining Energy Efficiency Potential

The economic energy-efficiency potential, or the amount of energy savings per year that can be economically achieved[43], is estimated using a bottom-up approach. While this type of analysis is data intensive, it generally yields more accurate results than top-down or macroeconomic-based approaches. The bottom-up approach used for the three major sectors of San Francisco (commercial, residential, and municipal) is summarized below.

1. Survey the total energy use of existing buildings and facilities in San Francisco by sector. Then survey the types of end-uses (lighting, space heating and cooling, water heating, etc.) that consume energy in buildings in each of these sectors.
2. Within each sector, break down energy use - first by building type or facility - then by energy end uses.[44]
3. Determine the amount of energy use attributable to each end-use in each building type or facility, within each sector.
4. Determine the efficiency measures that can be implemented for each of the significant end-uses (such as more efficient interior lighting, replacing existing HVAC equipment with more efficient technology, etc.)

[43] There is also "technical" potential, that is defined as energy savings that can be achieved using all possible technical improvements in all equipment, buildings, and processes regardless of cost. The technical potential is generally larger than the economic potential in energy savings analyses.
[44] For the purpose of this analysis, all residential units are treated equally.

5. Estimate the reduction in energy consumption that results from implementing the efficiency measures. This is the technical efficiency potential.[45]
6. For each efficiency measure in each sector, calculate the economic energy efficiency potential (GWh/yr)[46], and the levelized marginal cost of conserved energy ($/kWh)[47] for analysis and comparison purposes.
7. Within each sector, rank the measures from cheapest to most expensive, according to the levelized marginal cost of conserved energy.
8. The resulting order of the measures indicates the relative cost-effectiveness of the measures. By assuming that the measures will be implemented in this order, a level of cumulative energy savings achievable can then be calculated for any levelized cost.

Sources of data for estimates in the residential and commercial sectors

We used a 2002 study of technical and economic energy efficiency potential performed by Xenergy, Inc.[48] for the state of California both as an initial assessment of efficiency potential for San Francisco and as a source of cost data for these savings.[49] In order to apply the Xenergy data to San Francisco alone, we used PG&E billing data to establish the proportion of statewide use that is attributable to San Francisco. The percentages of total consumption attributable to each of the various end-uses in commercial and residential buildings were adjusted from the Xenergy report to better match San Francisco's particular climatic and economic conditions.

We believe that an efficiency potential estimate based only on the Xenergy analysis is overly conservative, and that greater energy savings are actually achievable for San Francisco. There are several reasons for this view.

First, the Xenergy study data set used in this analysis only considers savings potential in existing commercial and residential buildings. We added additional categories of efficiency potential in order to provide a more complete perspective. Some of the more significant additions include the following categories:

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[45] This is the potential energy efficiency that could be introduced in the projected year, regardless of economic feasibility. For the purpose of this report, only the economic potential is considered, as it is both more conservative in terms of energy savings and more realistic.

[46] The economic energy-efficiency potential for an individual measure represents an estimation of the energy efficiency improvement that would result from maximum use of the cost-effective technologies identified. The values are specific to San Francisco's particular loads and take into account the existing level of saturation of efficiency measures within the city.

[47] The levelized marginal cost of conserved energy is an annualized total cost, including the capital cost of the measure itself and the program cost, or estimated cost of administrative overhead needed to implement the measure on the scale described. Both of these costs are levelized (annualized) over the life of the savings achieved. The two costs are then added and divided by the annual savings, resulting in the levelized marginal cost of conserved energy. This and other methodological details are explained in J. Swisher, G. Jannuzzi and R. Redlinger, 1998. *Tools and Methods for Integrated Resource Planning: Improving Energy Efficiency and Protecting the Environment*, UNEP Collaborating Centre on Energy and Environment, Roskilde, Denmark. See chapter 3 and appendix 3.

[48] Rufo, M. and F. Coito. *California Commercial Sector Energy Efficiency Potential Study (ID#SW039A).* Pacific Gas and Electric Company. July, 9 2002

[49] For the residential and commercial sectors, which are served by PG&E, data that were only available for PG&E's entire service area (which includes more territory than just San Francisco) were factored down to represent only the City's share.

- Building retro-commissioning and continuous commissioning (commercial sector)
- Energy-efficient new construction (residential and commercial sectors) to achieve 40-50% energy savings compared to Title-24 standards
- LED holiday lights (residential and commercial sectors) to reduce winter peak demand

Efficiency in the municipal sector

The Xenergy study omitted consideration of the municipal sector, including City government buildings and facilities such as the San Francisco International Airport (SFO). Our estimates for the efficiency potential in this sector are based on energy savings estimated for municipal efficiency projects identified for the years 2003-2007, based on conversations with the San Francisco Public Utilities Commission and Hetch Hetchy Water and Power. In instances when cost data was unavailable for these projects, Xenergy data for buildings in the Commercial sector was used. We assume that municipal savings beyond 2007 increase by approximately the rate achieved during 2003-2007.

Second, our initial assessment of efficiency potential based on the 2002 Xenergy study considers potential reductions for only a limited number of end uses. Other energy end uses are not considered in this initial analysis and would further increase the achievable efficiency potential for the City for the commercial and residential sectors. RMI has included additional end-uses and energy-saving technologies in the portfolio analysis; however, the range of end uses and technologies remains incomplete.

Third, the achievable potential is based on the effectiveness of utility energy efficiency programs that have been conducted in the recent past, and it may be possible to improve on this performance in the future. The City, principally through the Department of the Environment, is working together with PG&E to tailor new DSM programs to the specific conditions in San Francisco. These new program design ideas, as well as others borrowed from successful programs from other cities and utilities, are included in the final chapter of this report, *Program and Policy Needs*.

Calculations of demand savings estimations for all sectors

Based on the economic energy-efficiency potential, annual increments in energy savings (kWh) were estimated. The resulting peak demand reductions impacting summer and winter peaks are calculated from these energy savings estimates, applying either a summer or winter coincident peak load factor. The coincident residential, commercial, or municipal peak is the sectoral demand at the time of the City’s summer or winter peak demand.

The summer and winter peak coincident load factors were calculated from PG&E’s weekday load profile data for 2000. The peak months for 2000 in San Francisco were September for the summer peak and December for the winter peak. In other years, the summer peak might occur anytime between May and October, but the load factor is reasonably uniform.

We estimate that about 1000 GWh/year can be saved in commercial buildings, 300 GWh/year in residential buildings, and 200 GWh/year in municipal facilities by 2013. These estimates include about 240 GWh/year in commercial new construction and 60 GWh/year in residential new construction (beyond the Title-24 standards). Applying the corresponding load factors, these energy savings translate to about 240 MW of total summer peak reduction and 230 MW of total winter peak reduction through efficiency by 2013.[50] These results are presented in the chapter *ERIS Portfolio Analysis Results*.

Based on our assumed rates of program implementation, energy *efficiency programs can completely eliminate load growth through 2020 in the low load growth scenario*. For the high load growth scenario, efficiency reduces the projected load growth to below the low load growth scenario levels.

We also performed a more detailed project-level financial analysis of both selected supply and DSM options to clarify the relevant incentives and barriers to implementation. The results of this analysis and its implications for policy and program design are discussed in the chapter *Project-Level Analysis*.

Cost-Effectiveness of Energy Efficiency Measures

The most cost-effective measures in commercial and residential buildings, as well as in municipal buildings are shown in Table 18, Table 19 and Table 20, respectively.

Table 18. Energy Efficiency Measures in the Commercial Sector

Building Type	Enduse	Economic Potential Savings (GWh)	Total Levelized Cost Per KWh Saved (Economic)	Cumulative Savings (GWh)
Food Store	Ventilation	0.2	$0.021	0
Hospital	Ventilation	0.5	$0.023	1
Food Store	Refrigeration	87.8	$0.025	89
Restaurant	Refrigeration	63.7	$0.025	152
Hotel	Refrigeration	26.6	$0.025	179
Misc.	Refrigeration	15.0	$0.025	194
Warehouse	Refrigeration	4.0	$0.025	198
Retail	Refrigeration	2.5	$0.025	200
Office	Refrigeration	1.2	$0.025	201
Hospital	Refrigeration	0.4	$0.025	202
School	Refrigeration	0.4	$0.025	202
College	Refrigeration	0.2	$0.025	202
Office	Ventilation	19.0	$0.032	221
Office	Lighting Phase 1	69.0	$0.035	290
Food Stores	Lighting Phase 1	14.5	$0.035	305
Warehouse	Ventilation	0.2	$0.036	305
Hospitals	Lighting Phase 1	32.5	$0.036	337
Hotel/Motel	Lighting Phase 1	8.3	$0.037	346
All Commercial	Commissioning	100.0	$0.040	446
Hospital	Outdoor Light	0.2	$0.041	446
School	Outdoor Light	0.1	$0.041	446
Misc.	Outdoor Light	0.9	$0.043	447
Warehouse	Outdoor Light	0.2	$0.044	447
All Commercial	New Construction	240.0	$0.045	687
Restaurant	Outdoor Light	1.9	$0.045	689

[50] These peak demand reductions do not include direct peak load management measures such as demand response programs that can reduce summer peak demand by at least 30 MW and winter peak by 10 MW.

Retail	Ventilation	0.3	$0.047	689
Restaurant	Lighting Phase 1	7.2	$0.047	696
Retail	Outdoor Light	2.4	$0.047	699
Retail	Lighting Phase 1	30.9	$0.048	730
Food Store	Outdoor Light	0.7	$0.049	730
College	Outdoor Light	0.1	$0.053	731
Hotel	Outdoor Light	0.9	$0.054	731
College	Ventilation	0.1	$0.060	732
Hospital	Cooling	5.8	$0.062	737
Warehouse	Lighting Phase 1	3.9	$0.065	741
Colleges	Lighting Phase 1	2.5	$0.065	744
Schools	Lighting Phase 1	2.1	$0.066	746
Miscellaneous	Lighting Phase 1	5.6	$0.069	751
Hotel	Ventilation	0.1	$0.075	752
Misc.	Ventilation	0.4	$0.076	752
Food Store	Cooling	2.9	$0.076	755
Office	Cooling	55.0	$0.109	810
Restaurant	Cooling	3.6	$0.112	813
Misc.	Cooling	3.4	$0.128	817
College	Cooling	2.1	$0.177	819
Hotel	Cooling	5.9	$0.225	825
Retail	Cooling	1.1	$0.227	826
Warehouse	Cooling	0.4	$0.234	826
Office	Lighting Phase 2	28.6	$0.257	855
Hospitals	Lighting Phase 2	13.5	$0.257	868
Retail	Lighting Phase 2	12.8	$0.257	881
Food Stores	Lighting Phase 2	6.0	$0.257	887
Hotel/Motel	Lighting Phase 2	3.4	$0.257	891
Restaurant	Lighting Phase 2	3.0	$0.257	894
Miscellaneous	Lighting Phase 2	2.3	$0.257	896
Warehouse	Lighting Phase 2	1.6	$0.257	898
Colleges	Lighting Phase 2	1.0	$0.257	899
Schools	Lighting Phase 2	0.9	$0.257	899
All Commercial	Office Equipment	61.0	$0.257	960

Table 19. Energy Efficiency Measures in the Residential Sector

End Use	Economic Potential Savings (GWh)	Total Levelized Cost Per KWh Saved (Economic)	Cumulative Savings (GWh)
Water Heating	0.8	$0.019	1
Central AC	0.1	$0.029	1
Water Heating	0.2	$0.029	1
Water Heating	0.2	$0.029	1
Pool Pump	14.4	$0.039	16
Water Heating	0.3	$0.039	16
Solar Heater Pump	0.5	$0.039	16
Hot Tub Pump	3.6	$0.039	20
Lighting	32.1	$0.039	52
Lighting	59.1	$0.039	111
Energy Efficiency in New Construction	60.0	$0.045	171
Room AC	0.1	$0.059	171
Space Heating	0.7	$0.069	172
Clothes Washer	0.9	$0.069	173
Water Heating	0.6	$0.069	174
Freezer	4.7	$0.069	178
Space Heating	2.5	$0.089	181
Dishwasher	2.0	$0.099	183
Vent = Furnace Fan	2.1	$0.099	185
Lighting	6.7	$0.099	191
Central AC	0.0	$0.109	191

Central AC	0.0	$0.129	191
Central AC	0.0	$0.139	192
Holiday Lights	2.0	$0.140	194
Space Heating	1.1	$0.149	195
Water Heating	4.1	$0.159	199
Refrigeration	33.1	$0.189	232
Space Heating	0.1	$0.209	232
Central AC	0.0	$0.219	232
Central AC	0.0	$0.249	232
Central AC	0.0	$0.269	232
Central AC	0.0	$0.269	232
Clothes Dryer	10.3	$0.299	242
Central AC	0.0	$0.349	242
Space Heating	0.1	$0.399	242
Room AC	0.0	$0.409	242
Room AC	0.0	$0.469	242
Central AC	0.0	$0.479	242
Central AC	0.0	$0.569	242
Central AC	0.0	$0.639	242
Water Heating	1.7	$0.669	244
Room AC	0.1	$0.729	244
Room AC	0.0	$0.789	244
Space Heating	0.3	$0.889	245
Residential Misc.	34.7	$1.023	279
Room AC	0.0	$1.039	279
Central AC	0.0	$1.169	279
Space Heating	0.1	$1.319	279
Central AC	0.0	$1.919	279
Room AC	0.0	$2.369	279
Central AC	0.0	$2.499	279
Central AC	0.0	$2.649	279
Room AC	0.0	$4.569	279
Central AC	0.0	$4.879	279
Room AC	0.0	$6.599	279
Room AC	0.0	$7.039	279
Central AC	0.0	$12.969	279
Room AC	0.0	$14.109	279
Room AC	0.0	$22.079	279
Room AC	0.0	$26.469	279

Table 20. Energy Efficiency Measures in the Municipal Sector

Building	Description	Economic Potential Savings (GWh)	Total Levelized Cost Per KWh Saved (Economic)	Cumulative Savings (GWh)
DPW - Water Pollution Control, Southeast	Increase efficiency of RAS Drives	0.12	$0.000	0
DPW - Water Pollution Control, Oceanside	Optimize No. 3 Water System	0.36	$0.001	0
DPW - Water Pollution Control, Southeast	Optimize No. 3 Water System	0.57	$0.004	1
DPW - Water Pollution Control, Oceanside	Modify O2 Generation System / Dissolution System	2.63	$0.013	4
DPW - Water Pollution Control, Southeast	Optimize secondary clarifier Channel Air Blower Energy Usage	0.17	$0.014	4
Water Department - Water Supply Division	Harry Tracy treatment plant - install variable frequency drive motors.	0.60	$0.015	4

Port of San Francisco	Provide loans to Port tenants to enable installation of energy efficiency measures, primarily HVAC- and weatherization-related.	2.50	$0.018	7
DPW - Water Pollution Control, Southeast	Optimize Inlet Channel Air	0.07	$0.018	7
DPW - Water Pollution Control, Southeast	Optimize O2 Reactor Operation	0.27	$0.019	7
Water Department - City Distribution Division	Lake Merced Pumping Station: install several energy efficient pumps.	1.40	$0.019	9
DPW - Water Pollution Control, Southeast	Replace Digester Recirculation Pumps with Wemco Hydrostal	0.32	$0.038	9
All Municipal	Commissioning	10.00	$0.040	19
Public Health - General Hospital	Lighting	3.22	$0.041	22
Police Department	Lighting	0.39	$0.043	23
Public Buildings	Lighting	1.85	$0.043	24
Port of San Francisco	Lighting	1.46	$0.043	26
Sheriff	Lighting	0.36	$0.043	26
Fine Arts Museums - Legion of Honor	Lighting	0.33	$0.043	27
DPW - Water Pollution Control, Southeast	Lighting	0.15	$0.043	27
DPW - Water Pollution Control, Oceanside	Lighting	0.04	$0.043	27
Rec & Park - Candlestick Park9	Lighting	0.04	$0.043	27
Water Department - Water Supply Division	Lighting	2.57	$0.043	29
Water Department - City Distribution Division	Lighting	1.05	$0.043	30
Social Services	Lighting	0.36	$0.043	31
Civic Center Court House	Lighting	0.27	$0.043	31
Programmatic energy efficiency	HVAC commissioning, small building retrofits, demand response, new rate structures, etc.	2.50	$0.047	34
Public Health - General Hospital	In 13 buildings at SFGH Medical Center, install 42,000 GE Ultra ballasts & watt-miser fluorescent lamps, 400 LED exit signs, 600 reflectors, and other energy efficient lamps.	3.22	$0.047	37
Airport	Phase 1 EE	35.67	$0.050	72
DPH Mental Health Clinic	Energy efficient lighting at 17 facilities.	1.50	$0.051	74
SFPUC	General retrofit	1.00	$0.053	75
Community Colleges and Public Schools	Lighting	3.32	$0.057	78
Public Library	LSR, adjusted	0.49	$0.058	79
Rec & Park General	LSR, adjusted	0.50	$0.058	79
Muni Railway	LSR	2.65	$0.058	82
War Memorial	LSR	0.74	$0.058	83
DPH Mental Health Clinic	Energy efficient HVAC modifications at 17 facilities.	0.40	$0.058	83
DPH Mental Health Clinic	Energy management systems at 17 facilities.	0.30	$0.058	83
Public schools and community college	Comprehensive energy efficiency retrofits	4.50	$0.065	88
Muni energy efficiency	Demand control and efficiency upgrades	3.60	$0.065	91
DPW - Water Pollution Control, Southeast	Energy efficiency measures including demand management controls, pumping and fans.	1.43	$0.072	93

Convention Facilities - Moscone Convention Center	Lighting, HVAC, building shell improvements and energy management controls.	4.57	$0.077	97
Convention Facilities - Moscone Convention Center	Lighting, HVAC, building shell improvements, and energy management controls.	4.57	$0.077	102
Traffic Lights	At 1100 City intersections, install LED traffic signals, reducing energy use by 82%	10.00	$0.082	112
Civic Center Court House	HVAC	0.15	$0.085	112
Social Services	HVAC	13.38	$0.085	126
Public Buildings	HVAC	1.03	$0.085	127
Police Department	HVAC	0.22	$0.085	127
Sheriff	HVAC	0.21	$0.085	127
Fine Arts Museums - De Young Museum	HVAC	0.19	$0.085	127
Fine Arts Museums - Legion of Honor	HVAC	0.18	$0.085	127
Water Department - Water Supply Division	HVAC	0.14	$0.085	128
Rec & Park - Candlestick Park10	HVAC	0.05	$0.085	128
Housing Authority Refrigerators	Within various housing developments, install 2000 Energy Star®-rated refrigerators.	1.23	$0.095	129
Airport	Phase 2 EE	48.24	$0.120	177
Parking Authority - Garages	Lighting	0.51	$0.137	178
HHWP Moccasin	Efficient pumps and demand control	2.00	$0.146	180
HHWP Moccasin	In 40 cottages, four buildings, Moccasin & Holm Powerhouses, install energy efficiency HVAC, weatherization, lighting system controls and lighting retrofits. Conservation education for employees.	0.40	$0.146	180
Public Health - General Hospital	Modify central heating and cooling plant, including a variable volume chilled water flow to HVAC systems.	0.20	$0.146	180
Rec & Park General	At various Golden Gate Park locations, install energy efficient lighting.	0.04	$0.234	180
Airport	Phase 3 EE	15.18	$0.260	195

These results can be expressed as marginal cost rankings, or “energy efficiency supply curves,” which show the relative magnitude of each resource option (in terms of kWh of energy or kW of capacity) over time, as well as their relative costs. An efficiency supply curve for each sector is shown in Figure 21. Efficiency supply curves plot the levelized marginal cost of conserved energy against the cumulative annual GWh savings. This gives a visual representation of the potential amount of energy that can be conserved at a given marginal cost within that sector.

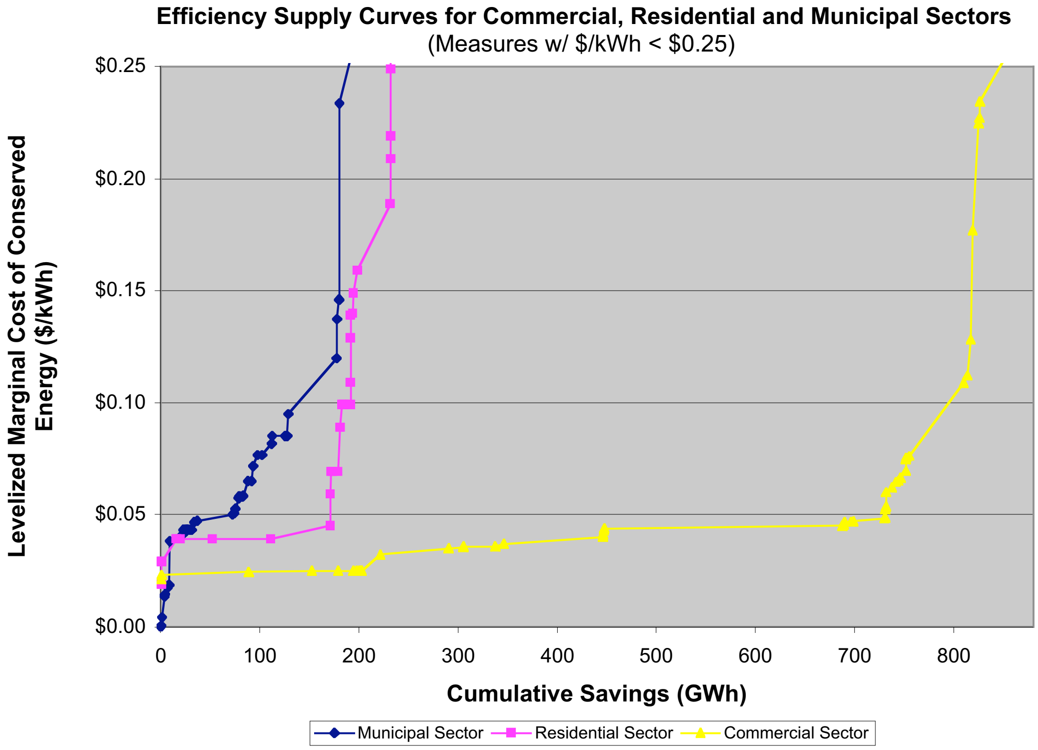


Figure 21. Marginal costs of conserved energy in each end-use sector in San Francisco

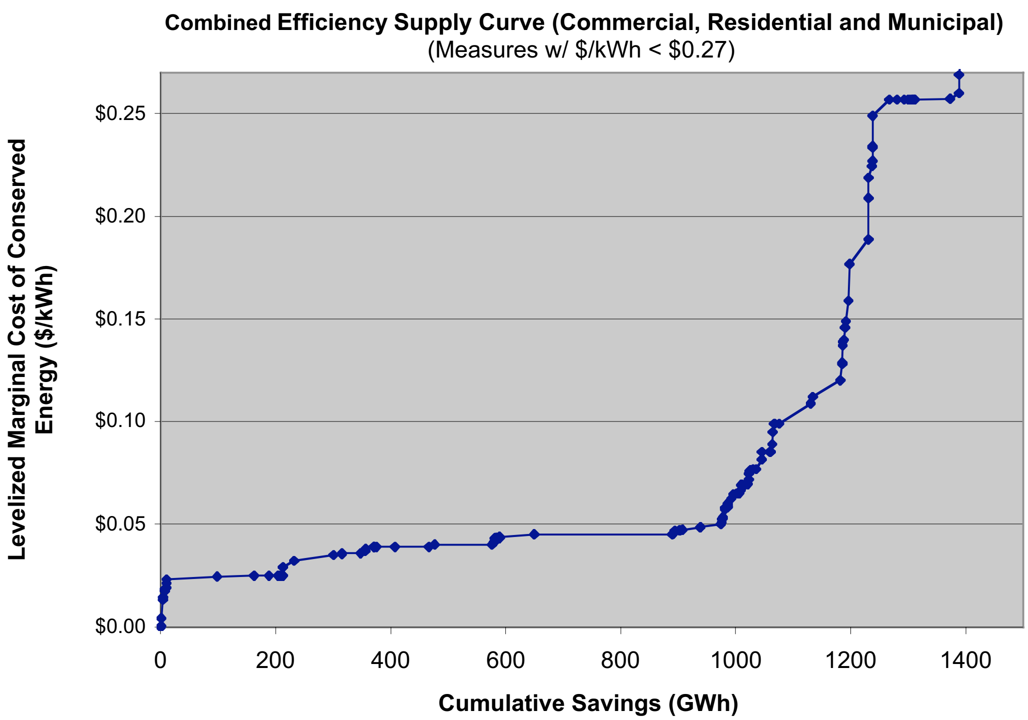


Figure 22. Combined marginal cost curve for energy efficiency in San Francisco

The three curves from Figure 21, corresponding to the commercial, residential and municipal sectors, are combined in Figure 22, which shows the potential cumulative energy-efficiency savings at a given marginal cost in San Francisco, considering efficiency measures in all three sectors.

Potential for Distributed Generation

In the short term, distributed (co-) generation (DG) can provide economic and environmental benefits. In the longer term, San Francisco's ability to complete the transition to clean, distributed power sources by replacing the last of its central generation sources in the City will involve aggressive deployment of DG technologies, including microturbines and fuel cells. As the costs of these technologies continue to fall, employing DG with cogeneration of heat for process or space heat, or for absorption cooling, will improve the cost-effectiveness of DG investments.

As a starting point in evaluating the potential for DG in San Francisco, an examination of the present and future trends in natural gas consumption helps to determine:

- Where sufficient thermal loads allow for increased system efficiency via co-generation
- What is the value of on-site (co-)generation compared to local alternatives and imports
- At what cost level will fuel cells and other distributed co-generation technologies become cost-effective, as a function of scale (large commercial, small commercial, residential)

Residential sector DG potential

San Francisco could be a good fit for residential co-generation, assuming that generation and waste heat recovery technologies are commercialized at this scale. Figure 18 clearly shows that the residential sector is the largest gas consumer in the City. About 93% of the residential natural gas is used for space heating and water heating. There appears to be a high load factor for gas heating in the residential sector.

In San Francisco, multifamily facilities (buildings containing two or more residential units) comprise only one-third of the total residential facilities in the city but two-thirds of the total dwellings. While the average electricity and gas consumption of a multifamily unit is slightly less than that of a single family unit, the aggregate energy consumption of all units within a multifamily housing facility is usually much greater than that of a single-family home. This characteristic of multifamily housing facilities make them the best candidates within the residential sector for targeting distributed generation technologies.

Table 21 summarizes the composition of the residential sector in San Francisco and indicates that the average multifamily building with five or more units has a total building square footage of approximately 5000 ft^2. To estimate the potential for distributed generation, data on residential gas and electricity consumption by housing type was taken from the PG&E Residential Energy Survey Report (1996). The system-wide average figures were adjusted to San Francisco's coastal climate zone to arrive at an estimate of total heating and electrical load per residential facility. These results are presented in Table 22.

Table 21. Breakdown of residential buildings in San Francisco

	Multifamily (>5 units)	Multifamily (2-4 units)	Single Family
Total area (million ft^2)	111	73	161
Total buildings	20,670	24,235	96,366
Average area per building	5,338	3,015	1,667
Assumed living area (ft^2)	750	900	1700
Average units per building	7	3	1

Table 22. Estimate of average residential heating and electrical loads in San Francisco

	Average area, ft^2	Average number of dwellings	Average gas consumption, billion Btu/yr	Average consumption, MWh/yr	Average demand, kW
Single family	1667	1	53	4.7	0.77
Multifamily, 2-4 units	3015	3	138	11.8	1.92
Multifamily, >5 units	5388	7	297	25.2	4.12
Downtown SF	7526	10	414	35.3	5.75

Notes: Coastal climate energy consumption is 0.72 of PG&E average. Coastal climate gas consumption is 0.98 of PG&E average. Source: PG&E Residential Energy Survey Report App A1-3 and A1-5.

Table 22 confirms that the average demand of multifamily units is much larger than that of single-family units, and therefore better candidates for small-scale cogeneration. Technologies being built on the scale of a few kW for residential cogeneration include fuel cells and Stirling engines. Single-family might be candidates for cogeneration, but their average demand is small, and their load factor is low compared to multifamily.

Based on the average heating and electrical demand for multifamily housing, the potential for residential cogeneration in San Francisco is estimated to be 90 MW and 3000 billion Btu. This estimate assumes that units are sized to meet the electrical base-load, avoiding the need to export power to the grid, which result in enough heat production to meet about 25% of the total heating load. Taking new multifamily residential construction into account, we estimate an additional DG potential of 6 MW could result from integrating DG technologies into building design.

Note that production of surplus electricity generation to sell to the grid would require net metering and possibly more complex utility interconnections in areas with concentrations of DG. Therefore, the feasibility of DG development would depend on the nature of the utility interconnection agreements and costs.

Commercial sector DG potential

Commercial buildings have a greater number of options for on-site DG technologies than residential housing since their energy consumption per building is typically much greater. Engines, small turbines, and stationary commercial-scale fuel cells typically have minimum generation capacities of 200kW or larger. Microturbines are generally installed in facilities with an average demand of 30kW or larger. The analysis for DG potential in the commercial sector focused on only office and hotel buildings downtown since detailed survey data for commercial buildings for the entire city are not available.

Table 23 profiles the office and hotel facilities in downtown San Francisco. Most of the floor area is in a few of the largest buildings. Buildings greater than 100,000 square feet make up 24% of the total number of buildings but 80% of the total floor area.

Table 23. Hotels and offices in downtown San Francisco

From	To	Total building floor area (million ft^2)	Number of buildings	Average Building Area (ft^2)	Percent of total floor area	Percent of total buildings
-	49,999	7.7	360	21,505	11%	58%
50,000	99,999	6.7	97	69,461	9%	16%
100,000	199,999	7.6	53	142,743	10%	9%
200,000	499,999	23.0	72	320,060	32%	12%
500,000	899,999	17.3	27	642,224	24%	4%
900,000	and up	10.5	9	1,164,944	14%	1%
Total		72.9	618	117,983	100%	100%

Table 24. Average annual energy loads for downtown hotels and office buildings

From	To	Average building gas load, billion Btu	Total heating potential, billion Btu	Average building electric load MWh/yr	Average building electric demand kW	Total co-generation potential, MW
-	49,999	0.5	180	276	45	8
50,000	99,999	1.6	156	892	145	7
100,000	199,999	3.3	176	1,833	299	12
200,000	499,999	7.4	535	4,110	670	36
500,000	899,999	14.9	402	8,246	1,345	27
900,000	and up	27.0	243	14,958	2,440	16
Total		2.7	1,692	1,515	247	107

Notes: Average annual gas use is assumed to be 23,200 Btu/ft^2, and 12.8 kWh/ft^2.
Source: PG&E, 1999 Commercial Building Survey Report, Tables 21 and 22.

Based on the building area data and assuming an average energy load per square foot, the average electrical load and gas use for downtown hotels and office buildings were calculated as shown in Table 24. The buildings larger than 100,000 ft^2 are the best candidates for DG in the form of cogeneration of heat, cooling and electricity with engines and stationary commercial-scale fuel cells with minimum generation capacities of 200kW or larger. Among the different DG options for commercial facilities, fuel cells are preferred because they are cleaner and more efficient than engines or microturbines. We expect that a few commercial facilities will install fuel cells in the next five years as demonstration projects, with higher penetrations of the technology in the longer term. Additionally, we assume that in the long term, fuel cells will be retrofitted in facilities that initially installed gas-fired engines. Facilities less than 100,000 ft^2 with smaller are better candidates for microturbines with cogeneration.

When the results obtained in Table 24 were further analyzed for building-level cogeneration, we determined that sizing DG to the average electric load resulted in a surplus of heating energy in office buildings. For hotel facilities, sizing to the average electric load produces almost enough heat to meet the facilities' heating needs. During a few months of the year (June-September), heating loads are reduced and surplus heat would have to be vented. However, waste heat from DG systems can also be used to drive absorption cooling systems, resulting in a more balanced thermal energy load that can make use of more of the waste heat produced during the year. To account for the limited utilization of waste heat from DG, we assume that systems are sized to meet 75% of the electric demand in buildings larger than 200,000 ft^2, and that waste heat is used for heating and cooling in these buildings. Because it might not be cost-effective to use waste heat for cooling in smaller buildings, we assume DG is sized for 50% of their electric demand.

This approach indicates a DG potential in existing, downtown hotels and office buildings of 107 MW. We use this as an estimate of the DG potential in San Francisco, and note that it is conservative because it omits buildings of other types and in other areas of the City. Finally, the analysis above does not take into account new commercial construction, which we estimate to offer an additional 35 MW of potential to integrate DG technologies in the facility design.

Municipal sector DG potential

The municipal sector is diverse, consisting of over 700 facilities administered by 45 departments, ranging from gymnasiums to sewage treatment plants, museums, schools and college campuses, police and fire stations, the bus and railway stations, and the San Francisco airport. Of the departments that reported both energy and gas consumption in 2000, 23 accounts have total demand of 200kW or greater, totaling 73 MW and 1600 billion Btu/year. Twenty-two accounts have total demand between 30kW to 199kW, totaling only 2MW and 140 billion Btu/year. Enterprise Account customers generally consume more energy per facility than General Account customers, but they are fewer in number.

Both Enterprise Account and General Account customers include unique, large facilities with very high usage that are more appropriately studied individually. For this analysis, the Muni railway and General Hospital (General Account customers) and the Airport (Enterprise Account) are excluded from the city's average consumption calculations. Table 25 summarizes the energy consumption data for large municipal facilities, excluding these three accounts.

Table 25. Municipal energy use in accounts >200kW load

	General Account	Enterprise Account	Totals
Number of accounts	12	8	20
Electric load MW	8.3	15.9	24.2
Average electric load kW	694	2,021	n.a.
Gas usage, billion Btu	762	80	842
Average gas usage, billion Btu	29	11	n.a.

Distributed generation technology options for the municipal sector are the same as those for the commercial sector. Gas engines, fuel cells, and microturbines are analyzed according to the average electrical and heating loads calculated for both General Account and Enterprise Account customers. In accounts greater than 200kW, heating loads are larger than the electrical loads for General Account customers, but heating loads are smaller than the electrical loads for Enterprise Account customers. As such, the resulting heat production from cogeneration, after sizing to the 8 MW electrical load, produces about 80% of General Account customers' heating needs. For the average Enterprise Account customer, however, it is better to size DG to the average heating load, and the resulting 4 MW electricity production meets about 25% of the facility's needs.

Of the large, unique accounts, the Muni railway has little DG potential due to small thermal loads, although other energy-saving and storage technologies such as flywheels may have useful applications. For SFO airport, sizing to meet approximately 100% of the airport heating load and a share of the cooling load (using absorption cooling) would provide 20 MW of electric generation, or about 60 percent of the average facility demand. For the General Hospital, sizing to meet about 50% of the hospital's large heating needs would result in a small surplus of electricity generation, producing 6 MW in total.

Summary of DG potential

The DG potential in San Francisco is diverse. There is significant potential for small DG in multifamily residential and commercial buildings. Large commercial and municipal buildings offer greater potential, and these applications are the most economic at present. Some of the large installations can also reduce electric loads by harnessing waste heat from power (co-) generation to drive thermal cooling systems such as absorption chillers. Finally, new construction of multifamily residential and commercial buildings will provide additional DG opportunities. The overall potential for DG potential in San Francisco is summarized in Table 26.

Table 26. Summary of future DG potential in San Francisco by sector

	30kW – 199kW DG potential, MW	≥200 kW DG potential, MW	Savings in cooling demand, MW	DG in new construction, MW	Heating load potential, billion Btu/yr
Municipal	-	38	5	-	900
Commercial	15	92	20	35	2000
Residential	90	-	-	5	3100
Total	105	130	25	40	6000

Integrating Supply and Demand-Side Options

In the ERIS methodology, demand-side management (DSM) measures such as energy efficiency improvements and distributed generation (DG) sources are considered as energy utility investments that can complement and compete with conventional, central supply technologies in energy resource planning. Thus, the next step is to rank the supply-side options in a similar way as the DSM options, and then to combine the supply and demand-side results in an integrated resource portfolio.

Two metrics are calculated for the ranking process, which correspond to the metrics used for the demand side:

- Annual generation (GWh)
- Levelized marginal cost of energy ($/kWh)

Annual generation is computed by multiplying the typical annual maximum capacity of a supply-side resource by the hours of operation (or capacity factor) for that resource. This yields the expected amount of energy that could be generated by such a resource each year.

The levelized marginal cost of energy is computed by dividing the total of the levelized costs (which includes capital, fuel, operations and maintenance costs, and emission costs, if used) by the annual generation. This represents the annualized cost per kWh of building and operating this resource.

Table 27. Costs of Generation Technologies in San Francisco

Generation Option	**Annual generation (GWh)**	**MCOE ($/kWh)**	**Cumulative Generation (GWh)**
Hetch Hechy hydro upgrade	131	$0.045	131
Utility scale wind	420	$0.047	552
Imports 1	2,716	$0.054	3,267
SF-owned Cogeneration	371	$0.060	3,638
Cogeneration	350	$0.068	3,988
Imports 2	767	$0.074	4,755
DG - small gas ICEs w/CHP	394	$0.086	5,149
Biomass direct combustion	61	$0.089	5,210
Hunters Point & Potrero peakers	182	$0.090	5,393
Potrero 3 (retrofit minimum)	319	$0.091	5,712
SF-owned CTs (peakers)	394	$0.094	6,106
DG - micro-turbines w/CHP	197	$0.099	6,303
Potrero 3 (retrofit maximum)	181	$0.101	6,484
DG – high temperature fuel cells w/CHP	131	$0.104	6,616
Simple-cycle CTs	131	$0.111	6,747
DG – low temperature fuel cells w/CHP	49	$0.134	6,796
Small scale wind	15	$0.155	6,811
Solar PV	83	$0.257	6,895

Similar to the demand side measures, the supply side resource options are ranked from cheapest to most expensive, according to the levelized marginal cost of energy, and the cumulative annual generation (GWh) is calculated. The most cost-effective supply options for San Francisco are shown in Table 27.

Figure 23 shows the resource supply curve, which plots the levelized marginal cost of energy from generation sources against the cumulative annual generation. It provides a visual representation of the potential amount of energy that can be generated per year at a given levelized supply cost.

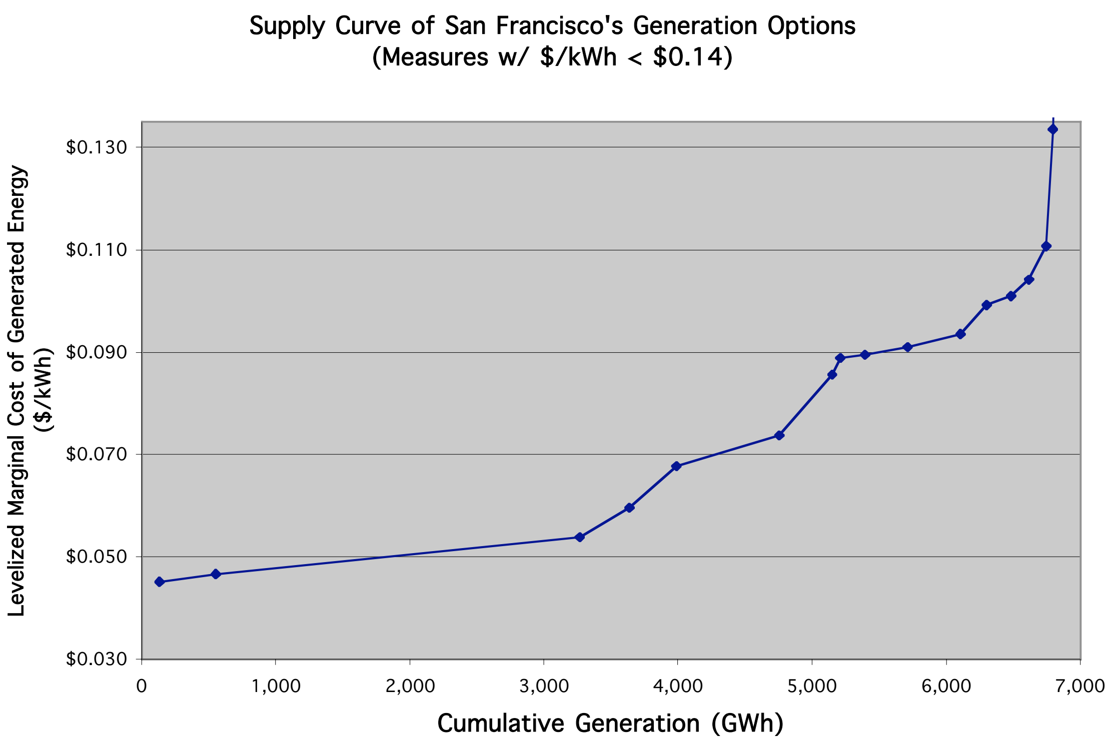


Figure 23. Marginal cost of energy ranking for supply options in San Francisco

The marginal cost curves in Figure 22 and Figure 23, which depict demand-side and supply options, respectively, are combined into the "integrated resource supply curve" for San Francisco in Figure 24.

In the integrated resource supply curve, energy efficiency and other demand-side options are evaluated alongside the supply options, and ranked in order of cost from the less expensive measures to the more expensive. This is the fundamental concept of IRP or the ERIS approach, i.e., that the community's energy service needs can be met either by producing, buying, or saving energy, or any number of combinations of each type of resource.

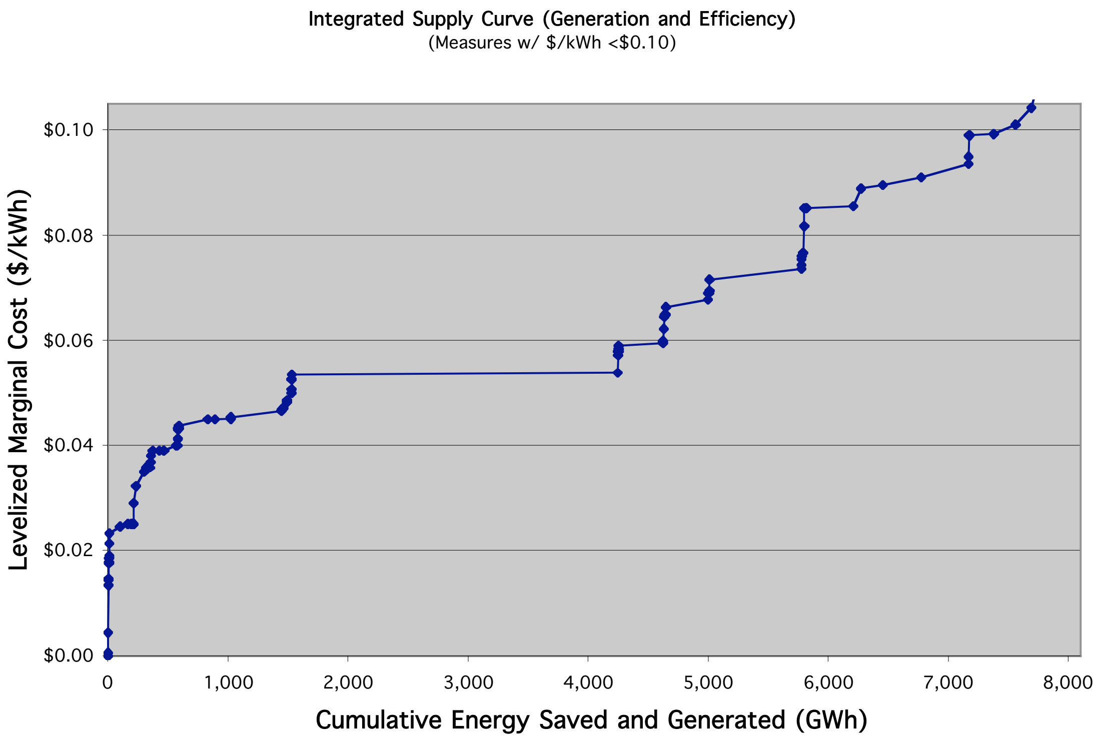


Figure 24. Integrated resource supply curve for San Francisco

The integrated resource supply curve for San Francisco shows that the City can provide almost 4000 GWh (almost 4 billion kWh) per year from the City's resources, both supply and demand-side, at a marginal cost of about $0.07/kWh or less, which is a reasonable cost level. Above this, level, additional resources become much more expensive, at least in the short to medium term.

The portfolio of energy supply resources must meet the annual and peak energy demand, net of DSM savings, in each scenario.

FUTURE ENERGY RESOURCE PORTFOLIO OPTIONS

The ranking of potential energy supply and demand-side options provides the menu from which we assemble a set of energy resource portfolio options, under a range of future scenario assumptions. These portfolios summarize our recommendations regarding the mix of existing and future energy resources to meet San Francisco's energy service needs, based on an assumed range of scenarios concerning demand growth, resource availability and technology performance. Three sets of portfolios are presented for various scenarios covering three future time horizons: short term (2006), medium term (2013), and long term (2020).

Short-term Portfolio Options (2006)

Planning constraints

Although the ERIS process is primarily meant as a long-term energy planning tool, the short-term energy planning issues, through 2006, are of special interest to San Francisco. The reason for this focus is that the City has pledged to close the Hunters Point Power Plant by that time. To fulfill this goal, the 163 MW capacity of the steam turbine generator at Hunters Point (unit 4) must be replaced by 2005. Ideally, the City would also close the combustion turbine (unit 1) at Hunters Point, enabling conversion of the entire site. In practice, this means that the California Independent System Operator (CAISO) must be convinced by *October 2004* that the City's power needs can be met with adequate reliability without this capacity.

Thus, the main planning constraints for the short-term portfolios are the closure of Hunters Point and the need to maintain adequate supply reliability in the City.

Variable assumptions

Of the many variables that govern the balance of energy supply and demand, we selected two primary variables for which assumed values should be explored in the short term through 2005. These two variables are the electric load growth and the decision to retrofit the steam turbine generator at Potrero Hill (unit 3).

Load growth, driven by local economic growth and employment, is the underlying driver of the need for energy resources. While there is always uncertainty in forecasting load growth, it is especially difficult at present, given the sharp economic downturn in recent years. Although most forecasts assume a resumption of more robust economic activity and growth, the timing of the recovery has significant implications for load growth in the near future. The two demand forecasts used in our scenarios and portfolio analysis are based on two different PG&E load forecasts. The higher forecast assumes an immediate (2004) resumption of growth and the lower of which delays this recovery about four years. Each load forecast continues to grow at 1.1-1.6%, not counting any incremental savings from energy efficiency programs, in the longer term.

Of San Francisco's two aging, fossil-fuel generating stations, the Hunters Point plant is expected to be decommissioned first, under an existing agreement between the City and PG&E. The remaining steam turbine plant at Potrero Hill (unit 3) is expected to be unable to operate at full capacity by 2005 unless it is retrofitted to reduce NOx emissions. The needed reduction would require the installation of selective catalytic reduction (SCR) technology. The retrofit would take several months and would allow Potrero unit 3 to operate for at least another five years.

2004 – 2006

The City is working to shut down Hunters Point in 2005. Plans are currently underway to site and contract for four 50-MW combustion turbines (CTs) owned by the San Francisco Public Utilities Commission (SFPUC) to be engineered and constructed in the City. Potrero unit 3 is permitted to operate as-is until January 2005, when it will have to be retrofitted or de-rated due to (NOx) emission constraints. The City has installed 675 kW of solar photovoltaics (PV) on the roof of the Moscone Center, with additional PV capacity planned (4 MW) through the end of 2005. Both the SFPUC and the San Francisco Department of Environment (SFE) have existing and planned projects and programs for City municipal and private entities to reduce energy consumption and peak demand in preparation for Hunters Point decommissioning.

The CAISO has indicated it will end the Reliability Must Run (RMR) contract for Hunters Point unit 4, thus permitting its shutdown, only if sufficient replacement generation is interconnected at a similar point in the network and several transmission projects are completed.[51] The transmission projects are the following:

- Ravenswood 230/115 kV transformer
- San Mateo-Martin Line #4 60 kV to 115 kV conversion
- Potrero-Hunters Point (AP-1) 115 kV underground cable
- Newark-Ravenswood 230 kV line rerate
- Ravenswood-San Mateo 115 kV line rerate
- Tesla-Newark 230 kV line upgrade

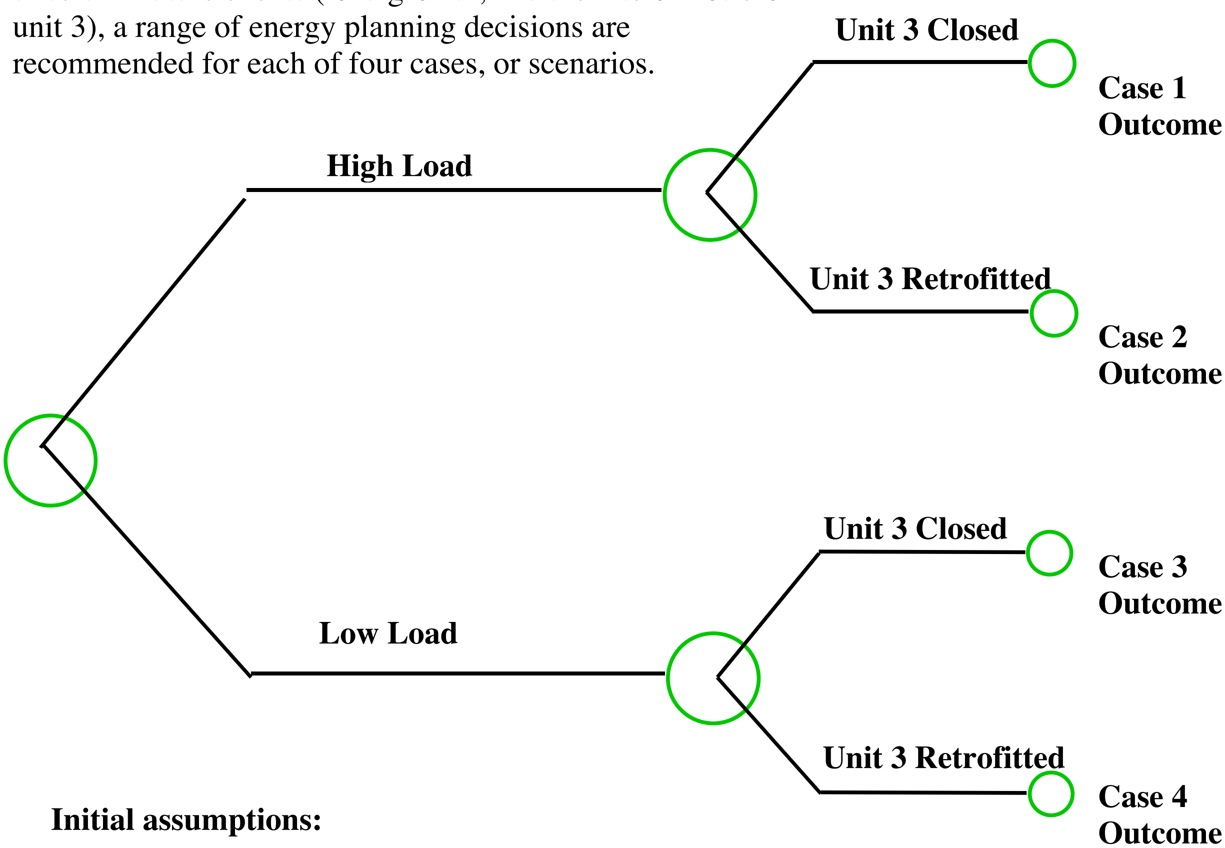
This means that the replacement generation, i.e., the City-owned CTs, must be interconnected on the 115 kV transmission network in the City and north of the Martin substation. The planned addition of the Hunters Point-Potrero 115 kV cable enables replacement generation to be located at places other than the Hunters Point substation. The new combustion turbines offer increased operating flexibility and improved system reliability through smaller, 48 MW capacity units and rapid startup (10 minutes in contrast to the 24-hour start times of Potrero 3 and Hunters Point 4).

The recent PG&E evaluation of the load serving capacity of the in-City transmission system concluded that the transmission system can allow for the closure of the Hunters Point plant once the Jefferson-Martin project and additional in-City transmission projects are completed. However, the timing of the Jefferson-Martin project is relatively uncertain and subject to potential delays in the permitting process. Therefore, we do not consider the transmission-only solution as adequate to allow the retirement of Hunters Point by 2005. Rather, it appears that Jefferson-Martin and other transmission upgrades will provide the necessary import capacity to allow the subsequent closure of the Potrero power plant while maintaining system reliability.

[51] California ISO letter from Terry Winter to Kevin Dasso and Theresa Mueller dated April 18, 2003, ISO Management Position on the Retirement of Hunters Point Unit 4.

Figure 25. SF Electricity Planning Decision Tree - 2006

Based on the initial assumptions below and the outcome of uncertain future events (load growth, and the fate of Potrero unit 3), a range of energy planning decisions are recommended for each of four cases, or scenarios.



Initial assumptions:

- **Hunters Point unit 4 closes by 2005**
- **Efficiency programs limit peak demand below 980 MW**
- **5 MW solar (3 MW peak) by 2005**
- **San Mateo – Martin line 4 on-line in 2005**
- **Other local upgrades to transmission are complete by 2005**

Energy resource portfolios for 2006

Selecting two possible states for each of the two key variables (load growth and the status of unit 3) produces four resulting scenarios, or cases within which San Francisco's energy needs would need to be met. These four potential cases are illustrated in the decision tree shown in Figure 25. The amount of supply and demand-side management (DSM) resources needed to meet reliability criteria will vary among the four cases, depending on the states of the assumed load growth and Potrero unit 3 status. To meet each of these projected resource needs, four resource portfolios are recommended, as shown in Table 28.

Table 28. Outcomes and Recommended Strategies for San Francisco Electric Resource Planning Cases – 2005

	Recommended Resource Strategy
Case 1 Outcome: High Load Growth, Unit 3 Closed	▪ 25 MW distributed generation by 2005 ▪ 140 MW in-City CTs in 2005 ▪ 50 MW in-City cogeneration in 2005 ▪ Potrero peakers continue to run until after Jefferson-Martin and Martin-Hunters Point (or Mission) are on-line ▪ Potrero unit 3 derated to 50 MW in 2005 ▪ Potrero unit 3 closes after Jefferson-Martin is on-line
Case 2 Outcome: High Load Growth, Unit 3 Retrofitted	▪ 25 MW distributed generation by 2005 ▪ 140 MW in-City CTs in 2005 ▪ 50 MW in-City cogeneration in 2005 ▪ Potrero unit 3 reopened in 2005, runs until after Jefferson-Martin and Martin-Hunters Point (or Mission) are on-line ▪ Potrero peakers continue to run until after Jefferson-Martin is on-line
Case 3 Outcome: Low Load Growth, Unit 3 Closed	▪ 20 MW distributed generation by 2005 ▪ 140 MW in-City CTs in 2005 ▪ 50 MW in-City cogeneration in 2005 ▪ Potrero peakers continue to run until after Jefferson-Martin is on-line ▪ Potrero unit 3 derated to 50 MW in 2005 ▪ Potrero unit 3 closes after Jefferson-Martin is on-line
Case 4 Outcome: Low Load Growth, Unit 3 Retrofitted	▪ 20 MW distributed generation by 2005 ▪ 140 MW in-City CTs in 2005 ▪ 50 MW in-City cogeneration in 2005 ▪ Potrero unit 3 reopened in 2005, runs until after Jefferson-Martin is on-line ▪ Potrero peakers close after 2005

With the closure of Hunters Point in 2005, required power imports into San Francisco will increase, and reserve capacity margins will drop to near the minimum level allowed by reliability standards. However, even with the derating of Potrero 3 as explored in scenarios 1 and 3, the reserve margin will still satisfy the necessary reliability and reserve capacity conditions.[52] If Potrero 3 is retrofitted, as in scenarios 2 and 4, the plant will be able to provide additional generation capacity in the City, and transmission capacity will be adequate to make up for the shortfall if Potrero 3 (rerated to 207 MW with the retrofit) trips or is down for maintenance.

In addition to Hetch Hetchy Water and Power's own hydroelectric facilities, additional power is also available for purchase from Calpine to supplement San Francisco's power needs through the end of 2006. However, this power is delivered to the Newark substation in the East Bay, and it therefore does not contribute to the load serving capacity within the transmission constraint on the San Francisco peninsula.

While San Francisco will have only begun to implement efficiency and renewable programs during this near term period, their contribution, together with distributed generation (DG) is not insignificant. We assume that the City's efficiency and renewable programs in the private and public sectors achieve a 3 percent reduction in demand by 2006, and that private DG provides another 3 percent contribution (see Table 29).

Table 29. Resource portfolio for 2006, summer season

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
	Hi load, no unit 3	Hi load, unit 3	Low load, no unit 3	Low load, unit 3
Required reserve margin capacity (MW)	104	259	104	259
Reserve margin	121	328	185	392
In-City capacity (MW)	371	578	369	576
In-City DG (incl. RE)	33	33	31	31
Total new renewable capacity (firm MW)	12	12	12	12
In-City generation, % of of net load	38%	59%	40%	63%

[52] The primary reliability condition is that the maximum annual load can be served despite the simultaneous loss of both the largest single transmission resource (the 230-kV line between San Mateo and Martin) and the largest single generation source (currently Potrero unit 3).

Medium-term Portfolio Options (2013)

Planning constraints

Assuming that the Hunters Point plant is closed in the 2005 time frame, the City will still have a rather old, inefficient fossil fuel-fired generation plant operating at Potrero Hill. Even if unit 3 is retrofitted to reduce its local NOx emissions, this plant is far from state-of-the-art technology. Although its continued operation is a key prerequisite for the decommissioning of Hunters Point in the short term, in the medium term Potrero will be the next candidate to be retired, as soon as it is no longer needed to contribute to electric supply reliability in the City.

Thus, the main planning constraints for the medium-term portfolios are the closure of the Potrero plant and the continued need to maintain adequate supply reliability in the City.

Variable assumptions

For the medium-term, we have selected three primary variables for which assumed values should be explored. These variables are the electric load growth, the impact of energy efficiency programs on this load, and the timing of the completion of the Jefferson-Martin transmission line. The resulting eight scenarios are shown by the decision tree in Figure 26.

As in the short term, load growth continues to be the underlying driver of the need for energy resources. The timing of San Francisco's economic recovery will have significant implications for load growth in the medium-term future.

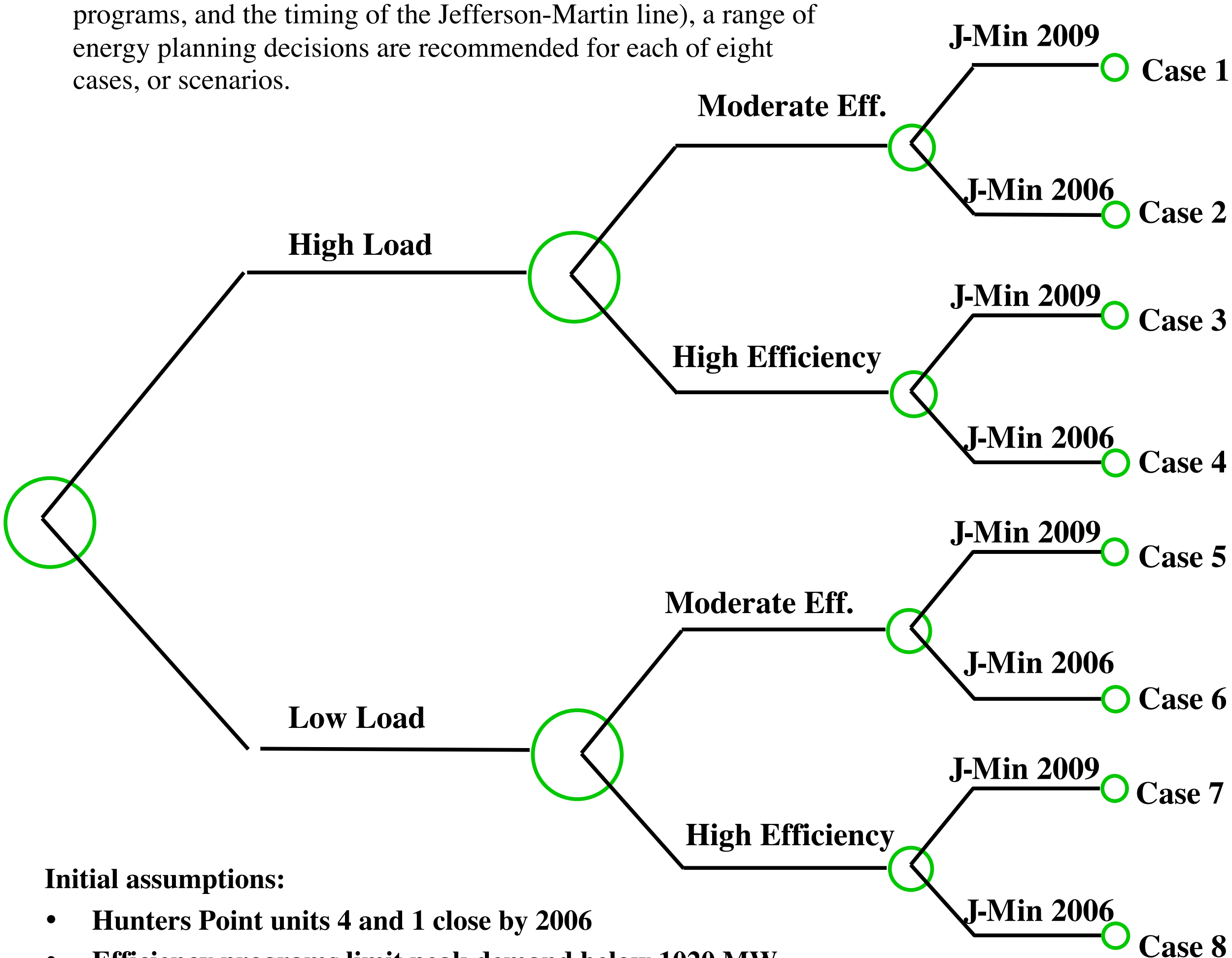
By 2013, we project significant reductions in peak demand due to energy efficiency and peak load management, which total up to 168 MW in the high growth scenarios (152 MW in the low growth scenarios). Although this total includes only about half of the estimated economic potential for energy efficiency, achieving it would require the successful implementation of very aggressive efficiency programs on the part of the City, PG&E, and the private sector. Therefore, we consider a second set of scenarios, in which the impact of efficiency programs is reduced by about a third. In these scenarios, the total peak demand reduction is 107 MW in the high growth scenarios (97 MW in the low growth scenarios).

The proposed 230 kV line between the Jefferson substation in Redwood City and the City's Martin substation would significantly increase transmission capacity to import power into the City. PG&E is currently in the process of obtaining regulatory permits for this project. PG&E is also studying an additional in-City transmission project between the Martin and Hunters Point or Mission substations, which will relieve an additional transmission constraint and further increase the import capacity via the Jefferson-Martin line. These new transmission projects could potentially relieve much of the risk of transmission congestion and reliability problems in the City with Hunters Point closed and Potrero unit 3 possibly retired or reduced in capacity.

This Jefferson-Martin project is scheduled to be on-line in 2006. However, this date is sufficiently uncertain that the City cannot delay other sources of power (and energy savings) in the 2004-2007 timeframe to ensure that reliability problems do not result from the retirement of the Hunters Point plant and potential delays in the completion of the Jefferson-Martin line. Thus, the timing of this project's completion will influence the selection of other supply and DSM resources during the time period 2006-2012.

Figure 26. SF Electricity Planning Decision Tree - 2013

Based on the initial assumptions below and the outcome of uncertain future events (load growth, the impact of efficiency programs, and the timing of the Jefferson-Martin line), a range of energy planning decisions are recommended for each of eight cases, or scenarios.



Initial assumptions:

- **Hunters Point units 4 and 1 close by 2006**
- **Efficiency programs limit peak demand below 1020 MW**
- **30 MW solar (20 MW peak) by 2012**
- **45 MW firm (125 MW nominal) wind outside SF by 2011**
- **San Mateo – Martin line 4 on-line in 2005**
- **Other local upgrades to transmission are complete by 2005**

Another variable that we include in the 2006 scenarios is whether the steam turbine at Potrero unit 3 would be de-rated and closed or be retrofitted to allow operation for at least another five years. Although this unit could operate farther into the future if retrofitted, we assume that it would be retired before 2013 as newer, cleaner resources become available to meet the City's needs. Thus, we do not consider a separate set of scenarios for 2013 based on the fate of unit 3.

2006-2012

The City's four 50-MW nominal combustion turbines (CTs) are assumed to be installed in 2005, with three units running in simple cycle configuration and one unit running as a co-generation plant providing both electricity and heat. This assumption can be realized if the SFPUC can finalize the siting of the turbines and offer an engineer-procure-construct (EPC) contract in time for the 12-18 month construction lead time for the CTs.

The 230-kV Jefferson to Martin transmission line, though planned for 2006, is conservatively assumed not to be in service until 2009 in half of our scenarios. This uncertainty is based on discussions with City staff and State officials on the status of the transmission project, which guided our estimate of when a most reasonable in-service date would be. Moreover, much of the additional import capacity provided by this line depends on the completion of the Martin-Hunters Point (or Mission) line, scheduled for 2010.

We assume that the import capacity added by these two transmission projects allows the Potrero power plant to be retired between 2006 and 2013. In the short-term scenarios where Potrero unit 3 is retrofitted, we assume that the existing peakers are retired first, as soon as Jefferson-Martin is on-line, and that unit 3 runs until the entire plant can be decommissioned. Note, however, that the plant would likely run at least through 2009 in any case to fulfill the terms of the renewed RMR contract with the CAISO, which will provide guaranteed revenue for the retrofit. In the case that unit 3 is not retrofitted but de-rated, we assume that it is retired first and that the peakers remain available until the entire plant can be decommissioned.

Note that the total load serving capacity is not the only criterion we use to determine when this plant can be retired. Criteria related to transmission system stability and load-serving capacity for the greater Bay Area must also be satisfied. The RMR contract for Potrero unit 3 is required by the CAISO partly because it enhances the stability of the greater Bay Area transmission grid. The CAISO has informed the City that unit 3 is several times more effective in terms of the Bay Area's load-serving capacity than generation in the East Bay. Thus, the CAISO expects unit 3 to continue running as an RMR unit until other generation is developed on the Peninsula or other transmission upgrades are developed to add import capability into the Bay Area.[53]

As explained under *Reliability and Reserve Margin*, we assume that, for system reliability and stability, at least one-third of the City's net load (after efficiency and load management) must be met by generation in San Francisco. Therefore, the balance between in-City generation and the net peak demand also determines the timing of the assumed retirement of the Potrero plant. In the high-growth, moderate-efficiency scenario, Potrero is needed until 2011, while in the low-growth, high-efficiency scenario, it is needed only until 2008. In the later case, however, the plant would run longer if either Jefferson-Martin is not complete, the terms of the renewed RMR contract have not been fulfilled, or the plant continues to be essential for Bay Area grid stability.

[53] Ed Smeloff, SFPUC, personal communication, 26 September 2003.

We also assume that, during 2006, the facility upgrades of Hetch Hetchy's hydroelectric stations are complete, allowing the generation stations to run at their original capacity ratings. We also assume that the renegotiated power supply contract with the Modesto Irrigation District takes effect in 2008, freeing up additional supply capacity to serve the City instead of the district, and that a similar arrangement with the Turlock Irrigation District takes effect before 2013.

New wind generation capacity outside of San Francisco is added, beginning in 2005 and reaching 125 nominal MW by 2013, and this capacity is financed by the City and through private developers. This power will be available for import into to the City from possible sites in southern Alameda County. There are already several existing wind farms close to San Francisco, including Altamont Pass (also one of the world's largest), Pacheco Pass, and Solano County, which sell power to PG&E. Generation outside San Francisco peninsula such as new wind capacity at Altamont Pass or in southern Alameda County will not directly alleviate capacity supply needs for the City within the transmission constraint north of San Mateo. However, it will reduce the emission intensity of the City's overall energy resource portfolio, as wind power produces no direct emissions. Increasing the share of wind and other renewable sources will reduce CO_2 emissions and improve the overall environmental quality in the Bay Area.

Energy resource portfolios for 2013

For 2012, the recommended resource portfolio choices are shown in Table 30. Reserve margins increase to comfortable levels by 2011 in all scenarios due to the addition of the Jefferson-Martin 230kV transmission line during 2006 or 2009, and the addition of the Martin-Hunters Point (or Mission) line around 2010. The construction of these lines increase import capacity to the city by up to approximately 350 MW.[54] The total import capacity into the northern Peninsula for 2013 is over 1300 MW. Netting out Peninsula loads south of the City, net import capacity is about 1000 MW. Subtracting the imports that San Francisco needs above what in-City generation can provide, the remaining import capacity or reserve margin for SF ranges from a low of 350 in scenarios 1 and 2 (summer season) to a high of 650 MW for scenario 7 (winter season).

Another reason that the reserve margins are more than adequate is that, following the retirement of Potrero unit 3, the largest remaining single generating unit is a 50-MW CT. This is the unit on which the first contingency criterion is evaluated and, since the new peakers are more reliable than the old peakers that are in use today, their capacity does not need to be derated to allow for the contingency that one does not start when called on. Therefore, the required generating reserve margin is only 50 MW in 2013, and all of the scenarios meet this condition easily.

The portion of in-City energy resources that comes from energy efficiency ranges from 9% in the high-load, moderate-efficiency scenario to 13% in the low-load, high efficiency scenario. Peak load management contributes another 1-2% of the summer peak capacity. Distributed generation from engines, microturbines, and fuel cells provides an additional 13% contribution to summer and winter peak capacity. Generation from new, renewable sources (excluding the existing Hetch Hetchy hydro) provides about 8% in 2013 (see Table 31). The contribution of renewable

[54] Realizing the full benefit to increase San Francisco's capacity to import power also depends on the completion of additional transmission projects in the South Bay.

energy is lower during the winter season due mainly to the lack of solar generation during the winter peak hours (which occur after dark).

Table 30. Outcomes and Strategies for Electric Resource Planning Cases - 2013

	Recommended Resource Strategy
Case 1 Outcome: High Load Growth, Moderate Efficiency, Jefferson-Martin Delayed until 2009	▪ 130 MW distributed generation by 2013 ▪ 140 MW in-City CTs in 2005 ▪ 50 MW in-City cogeneration in 2005 ▪ 10 MW fuel cell cogeneration by 2013 ▪ Remaining generation at Potrero closes after 2011
Case 2 Outcome: High Load Growth, Moderate Efficiency, Jefferson-Martin On-Line in 6/06	▪ 130 MW distributed generation by 2013 ▪ 140 MW in-City CTs in 2005 ▪ 50 MW in-City cogeneration in 2005 ▪ 10 MW fuel cell cogeneration by 2013 ▪ Remaining generation at Potrero closes after 2011
Case 3 Outcome: High Load Growth, High Efficiency, Jefferson-Martin Delayed until 2009	▪ 130 MW distributed generation by 2013 ▪ 140 MW in-City CTs in 2005 ▪ 50 MW in-City cogeneration in 2005 ▪ 10 MW fuel cell cogeneration by 2013 ▪ Remaining generation at Potrero closes after 2010
Case 4 Outcome High Load Growth, High Efficiency, Jefferson-Martin On-Line in 6/06	▪ 130 MW distributed generation by 2013 ▪ 140 MW in-City CTs in 2005 ▪ 50 MW in-City cogeneration in 2005 ▪ 10 MW fuel cell cogeneration by 2013 ▪ Remaining generation at Potrero closes after 2010
Case 5 Outcome: Low Load Growth, Moderate Efficiency, Jefferson-Martin Delayed until 2009	▪ 110 MW distributed generation by 2013 ▪ 140 MW in-City CTs in 2005 ▪ 50 MW in-City cogeneration in 2005 ▪ 10 MW fuel cell cogeneration by 2013 ▪ Remaining generation at Potrero closes after 2009, subject to RMR contract expiration
Case 6 Outcome: Low Load Growth, Moderate Efficiency, Jefferson-Martin On-Line in 6/06	▪ 110 MW distributed generation by 2013 ▪ 140 MW in-City CTs in 2005 ▪ 50 MW in-City cogeneration in 2005 ▪ 10 MW fuel cell cogeneration by 2013 ▪ Remaining generation at Potrero closes after 2009, subject to RMR contract expiration
Case 7 Outcome: Low Load Growth, High Efficiency, Jefferson-Martin Delayed until 2009	▪ 110 MW distributed generation by 2013 ▪ 140 MW in-City CTs in 2005 ▪ 50 MW in-City cogeneration in 2005 ▪ 10 MW fuel cell cogeneration by 2013 ▪ Remaining generation at Potrero closes after 2009, subject to RMR contract expiration
Case 8 Outcome Low Load Growth, High Efficiency, Jefferson-Martin On-Line in 6/06	▪ 110 MW distributed generation by 2013 ▪ 140 MW in-City CTs in 2005 ▪ 50 MW in-City cogeneration in 2005 ▪ 10 MW fuel cell cogeneration by 2013 ▪ Remaining generation at Potrero closes after 2008, subject to RMR contract expiration

Table 31. Resource portfolio for 2013, summer season

	Scenarios 1,2	Scenarios 3,4	Scenarios 5,6	Scenarios 7,8
	Hi load, moderate efficiency	Hi load, high efficiency	Low load, moderate efficiency	Low load, high efficiency
Required reserve margin capacity (MW)	104	104	104	104
Reserve margin	364	425	479	534
In-City capacity (MW)	359	359	332	332
In-City DG (incl. RE)	171	171	144	144
Total new renewable capacity (firm MW)	84	84	84	84
In-City generation, % of of net load	35%	37%	36%	38%

Long-term Portfolio Options (2020)

Planning constraints

In the longer term, after 2013, there is more time for capital equipment turnover, as well as more time for the development of newer, cleaner and more efficient technology. Most of the existing stock of energy technology base will need to be replaced, and the replacement technology will be over ten years more advanced than present technology and up to fifty years more advanced than some of the existing equipment being replaced!

For the City to achieve its goals related to sustainability, environmental equity, and greenhouse gas (GHG) reductions, it will have to take advantage of opportunities to replace aging energy infrastructure with state-of-the-art technology. Ideally, the City would like to decommission all conventional fossil fuel-fired simple generation (i.e., not co-generation) capacity by about 2020.

To achieve this type of goal, the City will have to rely increasingly on distributed co-generation technology, particularly cleaner sources such as fuel cells. This strategy is expected to be technically feasible in the 2012-2020 timeframe. However, its economic feasibility will require dramatic cost reductions and improvements in technical and economic performance to avoid a significant cost penalty for pursuing this strategy.

Thus, the main planning constraints for the long-term portfolios are the closure of existing fossil fuel generating plants, the continued need to maintain adequate supply reliability in the City, and the need to maintain or reduce the overall cost of providing energy services. In-City renewable resources continue to be limited by the intermittency of the resources and a lack of feasible sites within the Peninsula transmission constraint. Conventional distributed generation applications become saturated after 2013, and additional capacity can continue to be added only if cleaner, more flexible fuel cell technology becomes cost-effective.

Variable assumptions

We selected three primary variables for which assumed values should be explored in the long term through 2020. These variables are the electric load growth, the impact of energy efficiency programs, and the costs of fuel cell co-generation, as shown by the decision tree in Figure 27.

As in the medium term, load growth will continue to be the underlying driver of the need for energy resources. The amount of new supply resources needed, and possibly the selection of which resources, will depend on a combination of the long term trend in the growth of demand for energy services and the and savings that can be achieved from energy efficiency and load management programs after 2013.

To meet the City's long-term environmental goals, in-City central power generation will likely be eliminated, and even smaller sources such as the proposed City-owned combustion turbines (CTs) will be questionable. As noted earlier, solar power, even if its cost falls drastically, will be of limited value in terms of load serving capacity. Other renewable sources such as tidal current power are promising but will be difficult to site in the City, within the Peninsula transmission constraint.

Nevertheless, San Francisco will still need generation sources within the City, in order to meet its supply reliability needs. To meet both reliability and environmental needs, in-City generation must be highly efficient and low in emissions. These criteria dictate the use of co-generation and highly efficient technology such as advanced turbines and fuel cells. While these technologies exist and are in use today, their costs and long-term performance parameters need to improve significantly to become competitive on an economic basis with conventional technology.

2014-2019

This portion of the scenario analysis is beyond the time horizon of any energy studies or energy planning done for San Francisco to date. There are relatively little data available on the City's potential consumption and capacity expansion plans over this time horizon. However, the longer term perspective gives the City more freedom to build a vision of an energy resource mix that is realistic but that fully meets the City's environmental, social and economic goals. A longer time horizon gives the City the opportunity to start working towards such ten- to twenty-year goals.

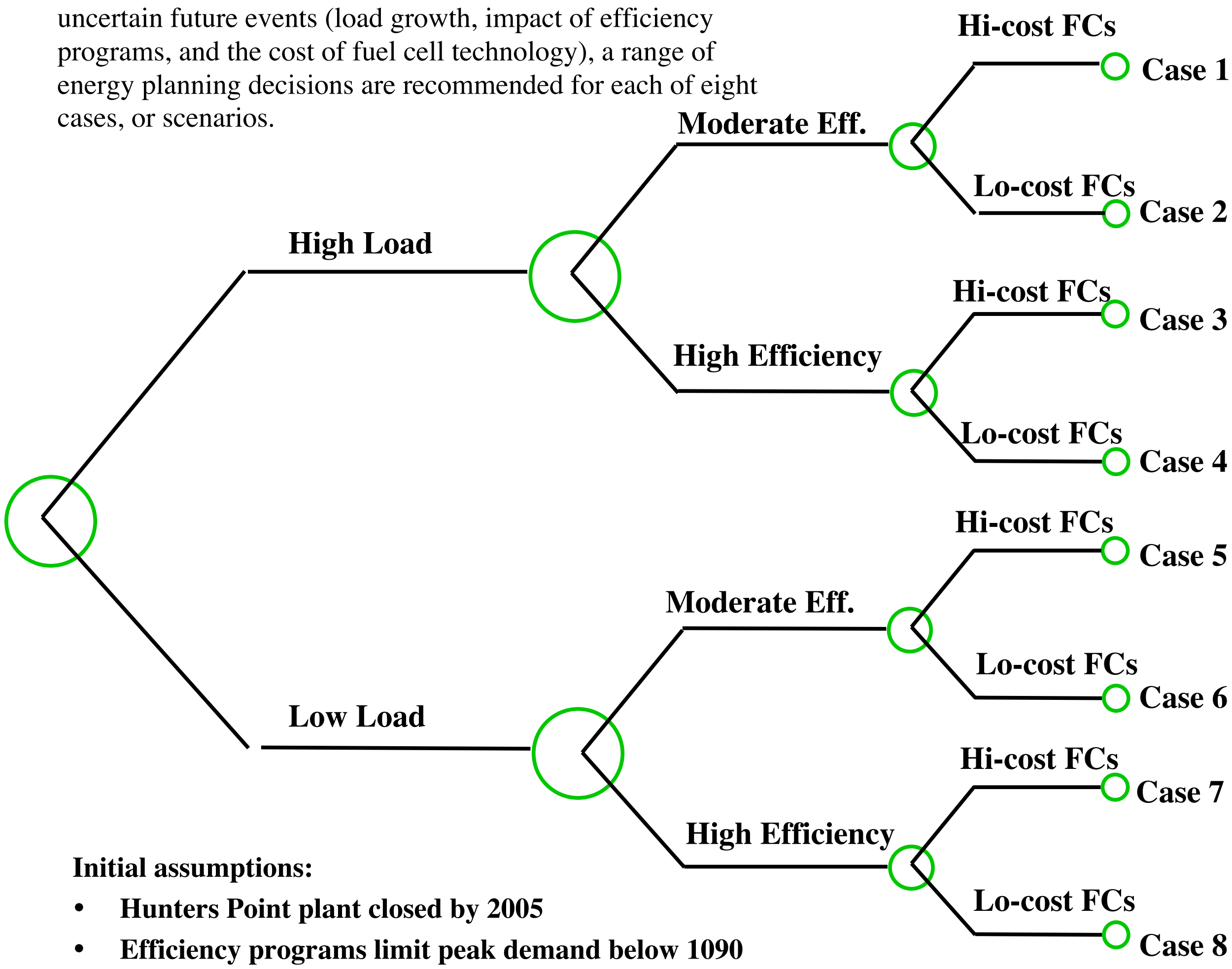
We assume in all scenarios that the remaining Potrero unit(s) are decommissioned by 2012. Because of the shut down of Potrero 3 and the peakers, the required imports will increase, but the reserve margin will still remain adequate.

We also assume that the power supply contract with the Turlock Irrigation District will be renegotiated and a new contract initiated before 2013, with similar terms to the new contract with the Modesto Irrigation District. This would release additional supply capacity to serve San Francisco instead of the districts. Note, however, that all Hetch-Hetchy power is delivered to the Newark substation, outside the Peninsula transmission constraint.

The primary option for new generation in the City is distributed generation, but sites for conventional systems are becoming scarce due to the need for smaller scale and quieter, cleaner operation. In scenarios 2, 4, 6 and 8, relatively low-cost fuel cells fill this gap, making it possible to retire the remaining CTs in the City. Most of the fuel cell generation is stationary production of combined power, heating and cooling. Another 50 MW of on-peak power is assumed to be available from a few thousand fuel cell vehicles operating in a vehicle-to-grid (V2G) mode.

Figure 27. SF Electricity Planning Decision Tree - 2020:

Based on the initial assumptions below and the outcome of uncertain future events (load growth, impact of efficiency programs, and the cost of fuel cell technology), a range of energy planning decisions are recommended for each of eight cases, or scenarios.



Initial assumptions:

- **Hunters Point plant closed by 2005**
- **Efficiency programs limit peak demand below 1090 MW**
- **45 MW solar (32 MW peak) by 2020**
- **San Mateo – Martin line 4 on-line in 2005**
- **Other local upgrades to transmission are complete by 2005**
- **Jefferson-Martin and Martin-Hunters Point lines are on-line by 2010**
- **Potrero unit 3 and peakers closed by 2011**

In most of the other scenarios, however, the combination of higher load levels and higher fuel cell prices require continued reliance on conventional generation technology. Only in scenario 7, with low load growth and high energy efficiency savings, does it appear feasible to close the remaining in-City peakers without the benefit of low-cost fuel cells. This scenario just barely satisfies our criterion of one-third in-City generation for system reliability and stability. Thus, we are not confident that the last central generation in San Francisco can be retired without the availability of low-cost fuel cells or a similar breakthrough in the cost and performance of a renewable energy technology.

In addition to the CTs, additional co-generation capacity is developed at the airport around 2014 in all scenarios except scenarios 6 and 8.[55] In these scenarios, low load growth and the availability of low-cost fuel cells allow the development of sufficient distributed generation in the City to offset the need for this additional generation on the Peninsula.

Energy resource portfolios for 2020

For 2020, the recommended resource portfolio choices are shown in Table 32. With the complete retirement of Potrero generation station before 2013, capacity in San Francisco is comprised of the Hetch Hetchy CTs, renewable and distributed generation capacity, as well as continuing energy efficiency and peak load management efforts. The CTs are retired by 2020 in all the scenarios with low-cost fuel cells. In the scenarios with either high load growth or expensive fuel cells, an additional 50 MW of conventional co-generation capacity is developed at SFO airport.

Without any other central generation development, the City relies more heavily on distributed co-generation. In scenarios 1, 3, 5 and 7, new distributed co-generation continues to rely on combustion technology, mostly improved combustion turbines. In scenarios 2, 4, 6 and 8, the majority of the incremental capacity for distributed generation relies on fuel cell technology. Larger installations with substantial thermal loads would use high-temperature fuel cells such as molten carbonate or solid oxide technology, while smaller installations with lighter thermal loads would likely use proton exchange membrane fuel cell technology.

A particular application of fuel cell technology in scenarios 2, 4, 6 and 8 is the connection of fuel cell vehicles to the hydrogen production and electric grid interconnection infrastructure in use for stationary fuel cell generation in the commercial sector. Vehicle to grid (V2G) infrastructure allows fuel cell vehicles to power the buildings where they park during the day. Operation of the vehicles' fuel cells during the day in the V2G mode can provide on-peak power generation using fuel cell capacity that is already paid for by the vehicle owner and fueling infrastructure that is already in place for stationary fuel cell systems. The generation output can shave daytime peak loads, reducing demand charges and energy bills. San Francisco's on-peak daytime loads (10am – 7pm) exceed the off-peak loads by about 100 MW during the summer and by about 50 MW during the winter. Assuming that fuel cell vehicles can generate an average 10 kW for the grid, 5000 vehicles employed for V2G would produce 50 MW for the City.

[55] The potential need for this capacity on the Peninsula is noted in the CEC Generation Infrastructure Report, February 2003.

Table 32. Outcomes and Recommended Strategies for San Francisco Electric Resource Planning Cases - 2020

	Recommended Resource Strategy
Case 1 Outcome: High Load Growth, Moderate Efficiency, High-Cost Fuel Cells	190 MW distributed generation by 2020 50 MW in-City cogeneration continues to run 140 MW in-City CTs continue to run 30 MW fuel cell cogeneration by 2020 70 MW firm (200 MW nominal) wind outside SF
Case 2 Outcome: High Load Growth, Moderate Efficiency, Low-Cost Fuel Cells	190 MW distributed generation by 2020 50 MW in-City cogeneration continues to run 170 MW fuel cell cogeneration by 2020 In-City CTs close in 2019 70 MW firm (200 MW nominal) wind outside SF
Case 3 Outcome: High Load Growth, High Efficiency, High-Cost Fuel Cells	190 MW distributed generation by 2020 50 MW in-City cogeneration continues to run 140 MW in-City CTs continue to run 30 MW fuel cell cogeneration by 2020 70 MW firm (200 MW nominal) wind outside SF
Case 4 Outcome: High Load Growth, High Efficiency, Low-Cost Fuel Cells	190 MW distributed generation by 2020 50 MW in-City cogeneration continues to run 170 MW fuel cell cogeneration by 2020 In-City CTs close in 2018 70 MW firm (200 MW nominal) wind outside SF
Case 5 Outcome: Low Load Growth, Moderate Efficiency, High-Cost Fuel Cells	150 MW distributed generation by 2020 50 MW in-City cogeneration continues to run 140 MW in-City CTs continue to run 30 MW fuel cell cogeneration by 2020 70 MW firm (200 MW nominal) wind outside SF
Case 6 Outcome: Low Load Growth, Moderate Efficiency, Low-Cost Fuel Cells	150 MW distributed generation by 2020 50 MW in-City cogeneration continues to run 170 MW fuel cell cogeneration by 2020 In-City CTs close in 2018 70 MW firm (200 MW nominal) wind outside SF
Case 7 Outcome: Low Load Growth, High Efficiency, High-Cost Fuel Cells	150 MW distributed generation by 2020 50 MW in-City cogeneration continues to run 30 MW fuel cell cogeneration by 2020 In-City CTs close in 2020 70 MW firm (200 MW nominal) wind outside SF
Case 8 Outcome Low Load Growth, High Efficiency, Low-Cost Fuel Cells	150 MW distributed generation by 2020 50 MW in-City cogeneration continues to run 170 MW fuel cell cogeneration by 2020 In-City CTs close in 2017 70 MW firm (200 MW nominal) wind outside SF

Co-generation capacity, based on traditional gas-fired combustion turbines at the San Francisco international airport, can be expanded in the future. In addition, depending on the future market status of fuel cells, SFO could install either gas turbines or fuel cells. New capacity between 50 MW (scenario 1) to 100 MW (scenarios 2 and 3) would help relieve transmission constraints for importing power into the City.

Generation outside the San Francisco Peninsula include Hetch Hetchy's hydroelectric turbines and new utility-scale wind turbines at wind farm sites outside the Peninsula. Hetch Hetchy's hydroelectric facilities will continue to play a significant role in meeting San Francisco's electricity needs in the long term, supplying up to 135 MW of power in the early spring season and up to 150 MW of power to San Francisco in the winter season. Up to 50 MW (170 MW nominal) of utility scale wind power capacity can be on-line by 2020 at wind farms to the east and south of the San Francisco Peninsula to serve the City and the Peninsula.

Other renewable energy resource options for 2013-2020

In addition to the technologies selected as part of our resource portfolios for each projected future scenario, we have identified additional renewable energy technologies that could contribute to the City's resource needs. These technologies, listed earlier under Resource Options, include tidal power in San Francisco Bay, solar thermal power for import, and pumped storage hydro for peaking capacity. Although it is presently unclear if these technologies can play a significant role in San Francisco's energy future, we recommend that the City continue to evaluate their potential. Positive developments regarding these technologies would provide additional planning flexibility and possible savings in future costs and emissions. Some of the issues concerning each technology include the following:

Pumped storage hydro capacity would provide additional peaking power capacity that could be dispatched at any time. This capacity would be sited outside the Peninsula transmission constraint and would not provide additional *energy generation*, but rather only *peak capacity*.

Solar thermal power would provide power that would reliably contribute to San Francisco's and the PG&E's systems summer peaks. However, this technology would have to be sited outside the Peninsula transmission constraint and might have transmission access limitations. There is more than 350 MW of solar thermal generation that was built in the late 1980s and is still operating in the Mojave desert with an annual capacity factor of about 27%. More recently, 50 MW of new capacity has begun to be developed for installation in Nevada.

Tidal power or *tidal current power* in San Francisco Bay may provide power with a relatively high capacity factor inside the transmission constraint, but development would be subject to severe siting constraints and permitting requirements that may be prohibitive. All of the several tidal power technologies now under development are immature, and their future performance, cost-effectiveness, and environmental impact are uncertain.

There is considerable progress being made in the development of tidal current power technology, which is similar to run-of-river hydropower and requires no impoundment of tidal flows. However, the key prerequisite for tidal power to provide useful energy to San Francisco is to find a strong match between the locations of adequate tidal energy resources and potential interconnections to PG&E's existing transmission system in San Francisco. It is unclear whether such suitable sites exist in the City. It may be that the most feasible sites in the Bay Area are in Marin or Contra Costa County. Tidal generation in these areas could provide clean energy but, like wind farms in Alameda County, would not contribute to the reliability of power supply within the Peninsula transmission constraint.

Summary of Portfolio Recommendations

In order to achieve San Francisco's energy planning goals, including supply reliability, cost-effectiveness, and environmental quality and justice, the City will need to ensure that certain resources are developed in time to meet new loads or replace older, existing resources. The exact amount and selection of these resources depends on several uncertain future outcomes, as shown in the scenarios presented here. Nevertheless, the following are key resources that are central to most or all of the portfolios we have recommended based on these scenarios.

1. In the 2005 time frame, the key resource to allow the Hunters Point plant to be decommissioned is the new City-owned combustion turbines, which can provide sufficient generation capacity within the Peninsula transmission constraint to maintain supply reliability without the continued operation of Hunters Point.

2. In the 2006-2013 timeframe, construction of the Jefferson-Martin 230-kV transmission line and the associated 115-kV Martin-Hunters Point (or Mission) line will provide additional insurance of supply reliability and make it possible to eventually decommission the Potrero plants. Also, to capture the full benefit of the Jefferson-Martin and related transmission upgrades, other transmission upgrades will need to be completed first. These upgrades include projects within the City (such as Hunters Point-Potrero), on the Peninsula (such as San Mateo-Martin line 4), and in the greater Bay Area (such as Newark-Ravenswood).

3. Throughout the entire time horizon, but especially in 2004-2007, San Francisco will need to aggressively implement energy efficiency and peak load management in order to help satisfy capacity reserve and reliability requirements. Particularly under scenarios where Potrero unit 3 is retrofitted and remains the largest in-City generation source, demand-side management (DSM) and other distributed resources will be key to ensuring adequate capacity reserves.

4. In addition, distributed co-generation in the private sector needs to become a significant resource in San Francisco during the next ten years. Current technology, based mostly on reciprocating engines, should evolve toward small combustion turbines and eventually fuel cells to improve performance and minimize GHGs and local emissions. In the longer term, distributed co-generation must become San Francisco's most important new source of supply-side capacity, in order to allow for the eventual closure of the remaining central fossil-fuel generation plants.

5. San Francisco will need to aggressively increase its energy efficiency and peak load management efforts over the entire planning period if it wishes to control peak demand and minimize power imports. The quantity of power imports to San Francisco could increase by 100% or more without the addition of large central generating unit. While the transmission capacity addition from the Jefferson-Martin line and other transmission projects will be adequate to handle the additional required imports, increased dependence on purchased power could make the City vulnerable to volatile fluctuations in power market prices. On the other hand, the City must be careful not to develop in-City central generation with so much

capacity under a single owner (250 MW plant or greater) that it becomes vulnerable to market power of a single power merchant.

6. Renewable sources can play an important role in the City's energy resources in the medium-to-longer term. In-City solar generation can make a small but significant contribution to meeting summer peak demand, due to its coincidence in time with the solar resource. The amount of useful solar power is limited by the relatively small difference between the City's summer and winter peak loads, as the winter peak occurs at night. A combination of in-City solar and peak load management can reduce peak demand to a comparable level in both seasons, making the best use of all supply resources.

7. Utility-scale wind power is unlikely to be developed in large quantity within the City and thus would not contribute to supply capacity within the Peninsula transmission constraint. However, there are excellent wind resources elsewhere in the Bay Area, and new wind farms in these areas could provide energy to the City at relatively low cost, provide a reliable hedge against fuel and power price volatility, and substantially reduce GHG emissions from the City's power supply. A small amount of in-City wind power is expected near the Bay.

8. Hydropower based on the Hetch Hetchy Water and Power system will continue to be an important resource for the City. The water and power supply and delivery infrastructure needs to be refurbished to maintain reliability and increase performance and power output. This dispatchable resource will become even more valuable with the addition of other intermittent renewable sources such as wind, because the hydropower can fill in additional power supply when the intermittent sources are not producing at full capacity. Renegotiation of the power supply contracts between the San Francisco and the irrigation districts in Modesto and Turlock will help the City gain more control over its supply resources.

9. Fuel cells are a key component to a longer term (post-2010) strategy to reduce and eventually eliminate central fossil-fuel combustion from the City's power supply mix. To achieve the potential offered by fuel cell technology, the City will need a robust infrastructure for distributed co-generation, based initially on conventional combustion technologies, and the economics of fuel cell technology will have to improve. We expect technological development over the next 5-10 years to reduce the costs of fuel cell (and related H_2 conversion) technology. Nevertheless, the economics of fuel cells and distributed generation in San Francisco can also be improved by collaborating with PG&E and customers to identify and capture additional economic value from reliability support, grid cost savings, and ancillary services. One aspect of fuel cell application could be the use of vehicle-to-grid (V2G) generation using fuel cell vehicles to meet on-peak electricity demand.

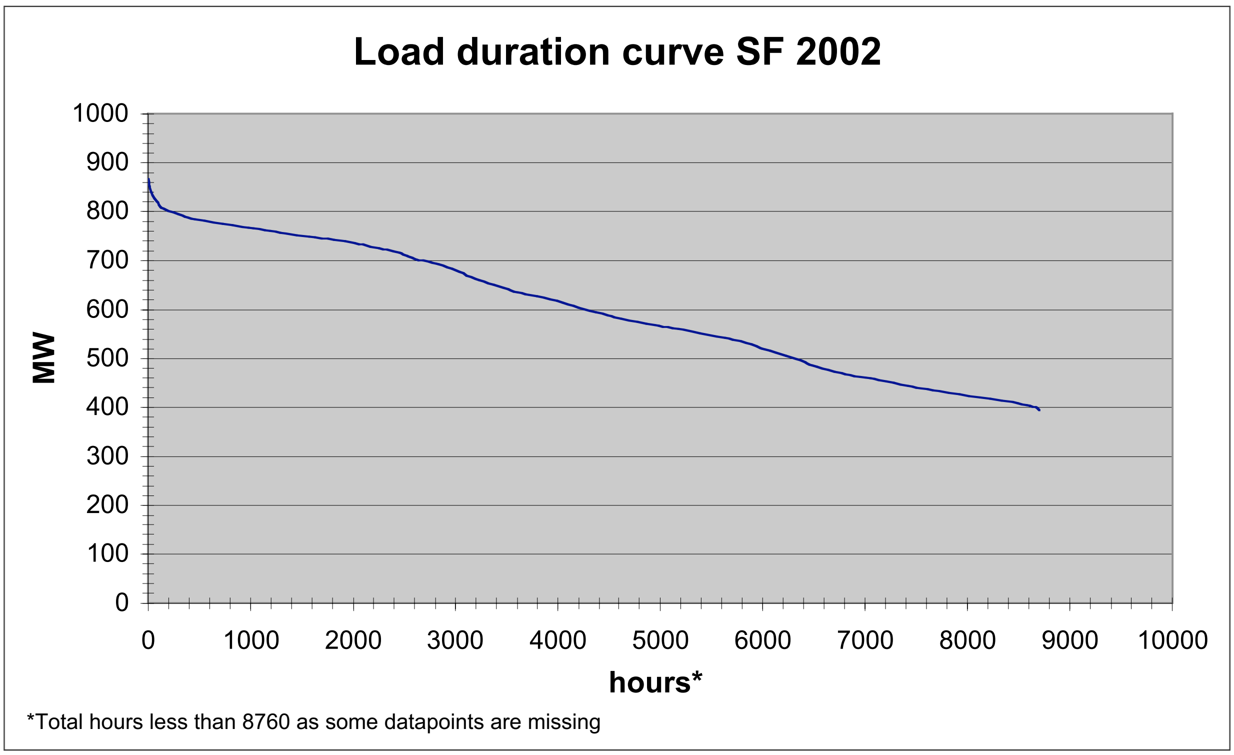
10. Other renewable energy resource options should continue to be evaluated to determine their potential application as part of a longer term (post-2010) strategy to reduce and eventually eliminate fossil-fuel generation from the City's imported power supply. These technologies include tidal power in San Francisco Bay, solar thermal power for import, and pumped storage hydro for peaking capacity. In particular, the development of technology to harness tidal current power is worth monitoring, as it could have promising applications in San Francisco Bay as the technology matures, provided that siting challenges can be resolved.

DISPATCH MODEL OF THE SCENARIOS

Given the generating mix and net demand (after energy efficiency and load management) in a specific scenario, it is necessary to estimate the service hours and annual production of all the in-City power plants under each future scenario. These estimates of generator operation, or dispatch, are used to determine the share of energy that is produced in the City and how much must be imported. Additional analyses associated with energy production determined by the dispatch model are plant maintenance and operation costs, fuel costs, and air emissions.

To project the power plant service hours and energy production, RMI developed a simple dispatch model for San Francisco. The dispatch model is derived from 2002 hourly aggregate load data for San Francisco supplied by PG&E. The loads are ranked from highest to lowest and the corresponding total hours of the year, and those loads are counted and then summed, producing a load duration curve as shown in Figure 28.

Figure 28. Load duration curve for San Francisco, 2002



The load duration curve is then scaled up to match the peak load for future years 2006, 2008, 2012, and 2020, based on PG&E (low load growth projection) and the CEC (high load growth estimate) load growth projections. The in-City plants expected to be in operation during the modeled years include Potrero unit 3, Potrero units 4, 5, and 6; possibly Hunters Point unit 1; a 50-MW natural gas turbine with cogeneration, and three 50-MW natural gas simple cycle turbines.

Approximately 700 MW of import capacity is expected to be available in 2006. Additionally, approximately 810 MW of import capacity is expected to be available in 2008, assuming that the Jefferson to Martin 230 kV line is placed in service, and this value increases to about 1040 MW with the addition of the Martin-Hunters Point (or Mission) line in the City. The total central plant capacities in the City for each of the modeled years are estimated according to Table 33.

Table 33. MW Capacity assumptions for dispatch model, all scenarios

	2006	**2008**	**2012**
Potrero 3 (minimum load)	52	52	0
Potrero 3 (maximum load)	207	207	0
Hunters Point 1	52	0	0
Potrero 4	52	52	0
Potrero 5	52	52	0
Potrero 6	52	52	0
New City Cogeneration	50	50	50
New City Peakers	140	140	140
Imports	700	810	1040
Total capacity, unit 3 retrofit	1258	1363	1230
Total capacity, no unit 3 retrofit	1103	1208	1230
CEC high forecast SF load*	1004	1045	1116
PGE low forecast SF load*	942	968	1008

*Excludes reductions from efficiency programs and distributed generation

We assume that the Hunters Point unit 1 CT will be retired by 2006 and that Potrero units 4, 5, and 6 are retired by 2012. Potrero unit 3 will be allowed to operate at full capacity if it is retrofitted with NOx emissions control. Otherwise it will be derated and limited to minimum capacity operation. Thus, two capacity totals are calculated, one assuming P3 is retrofitted and one assuming that it is not. One can immediately see from Table 33 that total central supply capacity will be adequate in 2012 to meet the projected City load, but that most of the total power supply will be imported from outside the City. The supply capacity shown is complemented by energy efficiency, load management, and distributed generation, which reduce the net load that must be served by central resources.

In addition to in-City power plant capacity assumptions, we assume a plant dispatch order based on discussions with the City:

1. New City cogeneration
2. Imports
3. Potrero 3 at minimum load
4. New City peakers
5. Potrero unit 3 ramp up to maximum load
6. Existing peakers (HP1, P4, P5, and P6)

The order in which plants are selected for use, or dispatched, is generally determined according to the lowest variable cost first. This is called economic dispatch. Once a plant is built and placed in service, the capital costs are sunk and it is only fuel and other operating costs that determine how existing plants should be used. A second dispatch method, called environmental dispatch, selects plant operation in order of those resources that are the cleanest, first.

Table 34. Marginal energy cost (MEC) and emission factors for in-city central generation

	MEC ($/MWh)	NOx (lb/MWh)	PM10 (lb/MWh)	CO_2 (ton/MWh)
New City cogeneration	0.049	0.1	0.04	0.4
Imports 1*	0.054	0.3	0.04	0.4
New City peakers	0.066	0.19	0.06	0.6
Imports 2*	0.074	0.3	0.04	0.4
Potrero (retrofit min load)	0.078	0.2	0.08	0.6
Potrero 3 (retrofit max load)	0.078	0.2	0.08	0.6
Potrero 3 (min load)	0.083	0.4	0.08	0.64
HP1, P4, P5, P6	0.090	3	0.14	0.94

*"Imports 1" are based on import capacity from committed transmission upgrades (e.g., line 4, Potrero-Hunters Point and substation upgrades). "Imports 2" is based on the addition of the Jefferson-Martin and Martin-Hunters Point (or Mission) transmission upgrades.

Table 34 shows the marginal energy costs (variable costs) and emissions factors for in-City central generation. The new in-City cogeneration plant has the lowest MEC and is dispatched first. Because it provides steam for district heating as well as electricity, it must operate as base load or more or less year-round. Imports via PG&E transmission lines have the next lowest marginal energy cost and are therefore "dispatched" second. Although Potrero 3 is less efficient and clean than the new City peakers, it is a large steam turbine unit that cannot cycle as quickly as the new City peakers and must be maintained on "standby" mode, at minimum load until it is needed during peak periods, when Potrero 3 would be ramped up to maximum load. The new City peakers, on the other hand, are much more responsive plants that can be started, ramped up or ramped down fairly quickly in response to the demand. The new peakers' MEC is lower than Potrero 3 as is or after its retrofit for NOx emissions control. The existing city peakers are dispatched last because they are relatively more expensive to run and, more importantly, are also the dirtiest plants. The existing peakers are limited in their annual permissible generation due to emissions limits set by the California Air Resources Board (CARB).

Based on advice from the CAISO and the City, the new City cogeneration plant is modeled to run 8,000 hours per year and the new City peakers are estimated to run a maximum of 1,000 hours per year, unless absolutely needed for system reliability. Furthermore, Portero 3 will only be allowed to operate at full (207 MW) capacity if it is retrofitted with NOx emissions control equipment, scheduled for completion in 2005.

These plant operating constraints and the load duration curve data shown in Figure 28 were input to the dispatch model to estimate annual operating hours for each in-City plant. The results of the modeling are shown in Table 35 through Table 37.

Table 35. Estimate of annual service hours of in-City central generation plants, high load growth scenario, Potrero is retrofitted

	2006 (baseline efficiency)	2006 (w/ high EE and DG)	2008 (baseline efficiency)	2008 (w/ high EE and DG)
Potrero 3 (minimum load)	2000	1500	1350	0
Potrero 3 (maximum load)	300	100	0	0
Hunters Point unit 1	0	0	n.a.	n.a.
SPotrero unit 4	0	0	0	0
Potrero unit 5	0	0	0	0
Potrero unit 6	0	0	0	0
New City Cogeneration	8000	8000	8000	8000
New City Peakers	3300	2600	1000	600

Table 36. Estimate of annual service hours of in-City central generation plants, low load growth scenario, Potrero is retrofitted

	2006 (baseline efficiency)	2006 (with high EE and DG)
Potrero 3 (minimum load)	2775	2000
Potrero 3 (maximum load)	100	0
Hunters Point unit 1	0	0
Potrero unit 4	0	0
Potrero unit 5	0	0
Potrero unit 6	0	0
New City Cogeneration	8000	8000
New City Peakers	2300	1500

Table 37. Estimate of annual service hours of in-City central generation plants, low load growth scenario, Potrero is *not* retrofitted

	2006 (baseline efficiency)	2006 (with high EE and DG)
Potrero 3 (minimum load)	2775	2000
Potrero 3 (maximum load)	n.a.	n.a.
Hunters Point unit 1	0	0
Potrero unit 4	100	0
Potrero unit 5	100	0
Potrero unit 6	100	0
New City Cogeneration	8000	8000
New City Peakers	2300	1500

Table 35 through Table 37 provide run hours for 2006 under several of our short-term scenarios, with and without the impact of estimated energy efficiency (EE) savings and distributed generation (DG) in the City. These resources reduce the required run hours of in-City central generation significantly, especially in later years. The high load growth scenario with Potrero 3 retrofitted is also run for 2008.

The results show that if Potrero 3 is retrofitted, there will be enough capacity in the city to meet CAISO plant operating criteria and serve the City loads without needing to operate the existing Potrero peakers. If Potrero unit 3 is *not* retrofitted, the existing peaking plants will need to operate instead, at least until about 2008. Additional import capacity from the Jefferson-Martin line in 2008 also contributes to reductions in the run hours of in-City generation.

In the high load growth scenario, the new in-City peakers will likely need to operate above its target of 1,000 hours per year. However, because these units are dispatched ahead of either the Potrero unit 3 ramp-up or the Potrero peakers, these resources are not needed to operate many hours if at all. As time goes on, the increasing impact of energy efficiency and the additional DG capacity make it possible to reduce the run hours of the central plants further, and eventually to retire them during the period 2008-2012, as shown by the resource portfolios discussed in the previous section.

ERIS PORTFOLIO ANALYSIS RESULTS

RMI analyzed the energy, economic and environmental implications of the ERIS portfolios selected under each scenario, as described in the preceeding section. Below we summarize the results of this analysis. Rather than present an exhaustive catalogue of quantitative results from all the scenarios, we have selected a subset of the scenario results to illustrate the main points of discussion for each topic. In some areas, we show results from most or all of the scenarios, and in other areas we use one or two scenarios to illustrate the important trends and conclusions.

Energy and Peak Demand

Following the bottom-up analysis approach to the scenario analysis of the energy resource portfolios, we treat energy efficiency and peak load management as an energy resource comparable to new electricity supplies. Therefore, we present the results of our resource model according to the combination of supply and demand-side resources that are needed to meet the total projected demand for electricity services in each scenario. We address both total consumption and peak demand. Based on the complex electric system boundaries discussed in the *System Boundaries* section earlier in this report, we ensure that adequate transmission capacity for power imports is available, reserve margins are sufficient to satisfy first-contingency planning conditions,[56] and at least one-third of required generation capacity is located in the City (including distributed generation).

The impact of demand-side management (DSM) and distributed generation (DG) on the demand for central generation is shown in Figure 29 for the low baseline growth scenarios and in Figure 30 for the high baseline growth scenarios. It appears that DSM is capable of limiting future net demand growth to about zero, for example in the high-growth, high-efficiency scenario (cases 3, 4)) or in the low-growth, moderate-efficiency scenario (cases 5,6). The remaining demand must be met by a combination of DG and central generation, including imports.

The impact of DG is to reduce the net demand for central generation to about half of the original demand forecast in the later years of each of the high efficiency, high DG scenarios (cases 4,8). At that time, most or all of the remaining central generation could be supplied via imports. With in-City generation dominated by DG and co-generation, and a growing share of this in-City DG provided by fuel cells, both global and in-City emissions can be reduced significantly.

[56] This criterion requires a reserve margin of about 200 MW in each scenario, corresponding to the largest generating unit. Because the transmission capacity is already designed on the basis of the first-contingency criterion, the San Francisco electricity supply system is really expected to withstand *second-contingency conditions* (simultaneous loss of two major components, either generation and/or transmission).

Figure 29. Net demand on central generation under low-growth demand scenarios

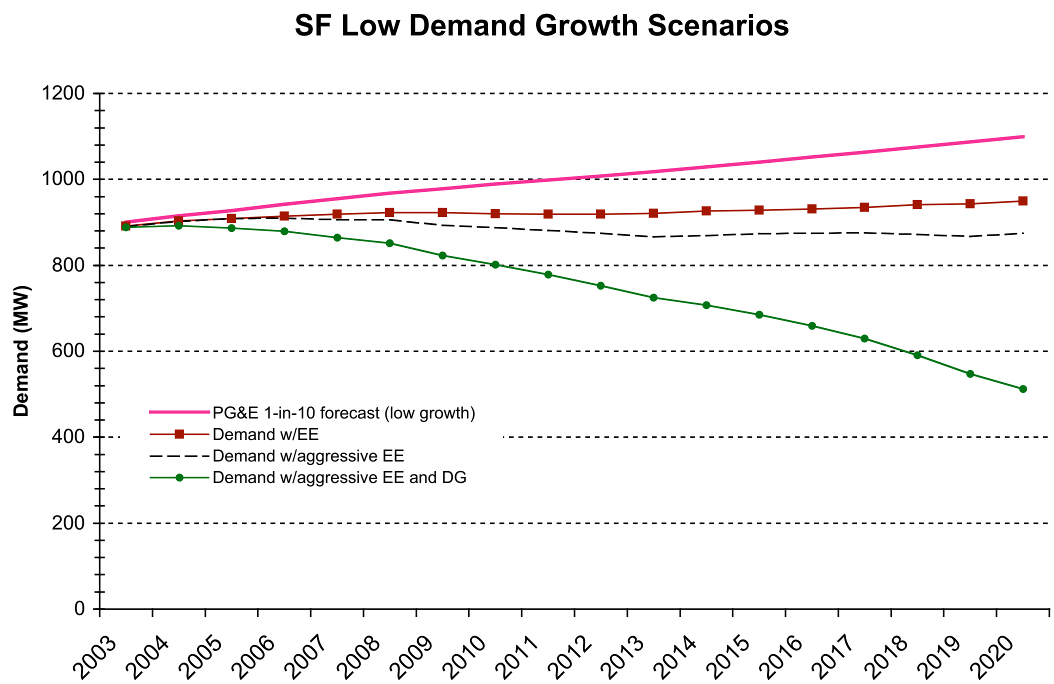
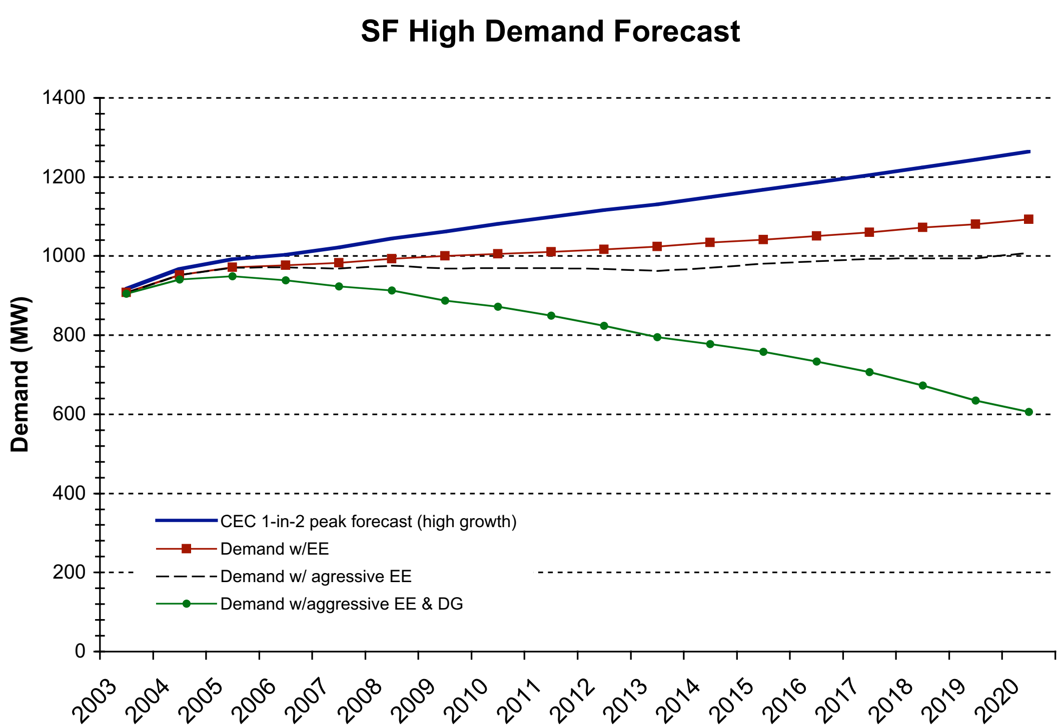


Figure 30. Net demand on central generation under high-growth demand scenarios



One concern with a large increase in co-generation capacity in the City is how to meet summer and winter peaking demand, given that co-generation typical needs to be operated most of the time to serve the host building's heating or cooling load, regardless of citywide power demand. In the later years of the aggressive DG scenarios, the peak demand is served by a combination of:

- Demand response and other peak load management programs,
- Peak coincident in-City solar (summer peak only),
- Grid-connected vehicular fuel cells running in the V2G configuration, and
- Power imports from renewable and conventional sources outside the City.

The results of one scenario (case 2) are shown in terms of summer peak load and capacity resources in Figure 31 and Table 38, and the winter peak load and capacity results are shown in Table 39. In this scenario, we assume relatively fast baseline energy demand growth and only moderate impact of energy efficiency programs. Thus, this scenario has the highest net demand (after efficiency and load management) of any of the scenarios we considered. This scenario assumes that low-cost fuel cells become available in time to contribute to DG resources by 2020.

Table 38. Summer peak capacity summary for high load, moderate efficiency scenario*

	Summer Peak Load and Capacity (firm MW)		
Resource	2006	2013	2020
Projected baseline demand	1004	1131	1264
Energy efficiency savings	23	80	141
Peak load management	3	27	30
Net load on supply resources	976	1024	1093
Potrero unit 3	207	0	0
HP1 & Potrero peakers	156	0	0
New In City cogeneration	47	47	47
New In City peakers	140	140	0
DG - ICEs & turbines	27	135	193
DG - fuel cells	0	12	173
Renewables in CCSF	7	23	40
Utility scale wind	20	47	71
Hetch Hechy hydro	130	200	200
HH-Calpine contract	55	0	0
Peninsula generation	25	25	115
Net Import capacity	700	1040	1040

*Assumes Potrero unit 3 is retrofitted before 2006 and low-cost fuel cells are available by 2020.
Note: Firm MW is capacity available to meet summer peak loads, e.g., 70% of nominal solar capacity.

In this scenario, the Hunters Point power plant is retired in 2005; the Potrero plant is retired in 2011 (and the peakers earlier); and the new in-City combustion turbines (CTs) are retired in 2019. The combination of moderate energy efficiency gains and aggressive development of distributed generation, including fuel cells, is sufficient to replace all central fossil fuel-fired generation in the City by the end of this scenario.

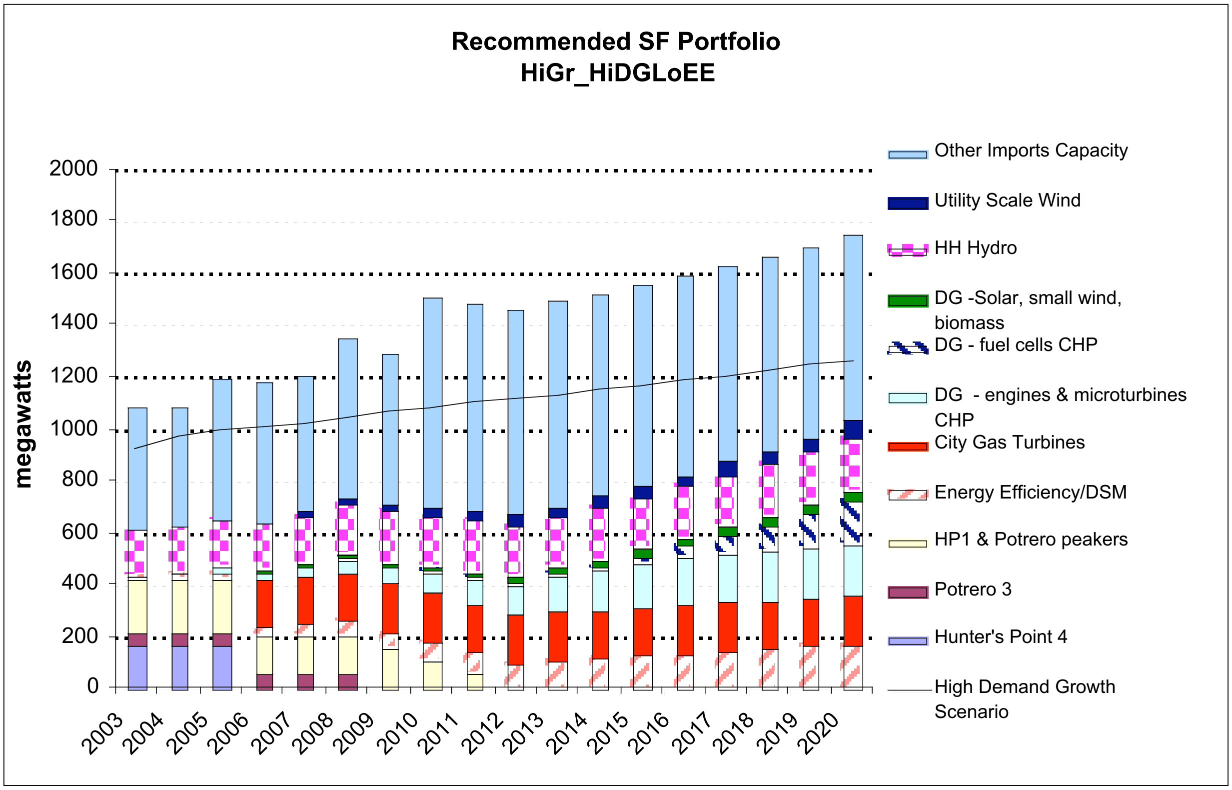


Figure 31. Resource portfolio to meet peak demand: high demand, high DG

Table 39. Winter peak capacity summary for high load, moderate efficiency scenario*

	Winter Peak Load and Capacity (firm MW)		
Resource	2006	2013	2020
Projected baseline demand	960	1082	1209
Energy efficiency savings	24	76	132
Peak load management	1	9	10
Net load on supply resources	935	997	1067
Potrero unit 3	207	0	0
HP1 & Potrero peakers	156	0	0
New In City cogeneration	47	47	47
New In City peakers	140	140	0
DG - ICEs & turbines	27	135	193
DG - fuel cells	0	12	173
Renewables in CCSF	3	4	5
Utility scale wind	20	47	71
Hetch Hechy hydro	130	340	340
HH-Calpine contract	40	0	0
Peninsula generation	25	25	25
Net Import capacity	700	1040	1040

*Assumes Potrero unit 3 is retrofitted before 2006 and low-cost fuel cells are available by 2020.
Note: Firm MW is capacity available to meet winter peak loads, e.g., 30% of nominal wind capacity.

For the same scenario, the results in terms of annual energy use and production are shown in Figure 32 and Table 40. The generation dispatching in this scenario is able to meet all net demand (after efficiency and load management) without needing to operate the CT peakers at Potrero, which are the most polluting generation source in the City. These units are needed in 2006 for reserve capacity to meet PG&E and CAISO reliability criteria, but don't necessarily need to run if other generation sources and transmission lines are available and operating properly.

Distributed generation, initially from combustion sources and later from fuel cells, meets an increasing share of the demand, and renewable energy from in-City solar, remote wind farms and Hetch Hetchy hydro upgrades provide significant quantities of clean energy. As a result, the need for imports from the power market decreases over time. The City becomes somewhat more self-sufficient in electricity, although all gas is still imported.

Note that, in this and all the scenarios analyzed, Hetch Hetchy hydropower and utility windpower are resources located outside the Peninsula transmission constraint. While they provide clean energy for the City's needs, they do not contribute to meeting supply reliability requirements in San Francisco and the northern Peninsula.

Table 40. Annual energy output summary for high load, moderate efficiency scenario

	Annual Energy Use and Production (GWh)		
Resource	2006	2013	2020
Projected baseline demand	5973	6729	7520
Energy efficiency savings	164	543	906
Net load on supply resources	5809	6186	6614
Potrero unit 3	208	0	0
HP1 & Potrero peakers	0	0	0
New In City cogeneration	372	372	372
New In City peakers	503	168	0
DG - ICEs & turbines	122	604	859
DG - fuel cells	0	72	920
Renewables in CCSF	20	50	80
Utility scale wind	55	130	198
Hetch Hechy hydro	990	1890	1890
HH-Calpine contract	416	0	0
Peninsula generation	146	146	146
Purchased imports	2977	2654	1720

Detailed scenario results are shown below for another scenario, the low-demand, high efficiency, low DG scenario (case 7). The resource portfolio for this scenario is shown in Figure 5. With low baseline demand growth and high impact from efficiency programs, the net demand (after efficiency and load management) is the lowest of any of the scenarios we considered.

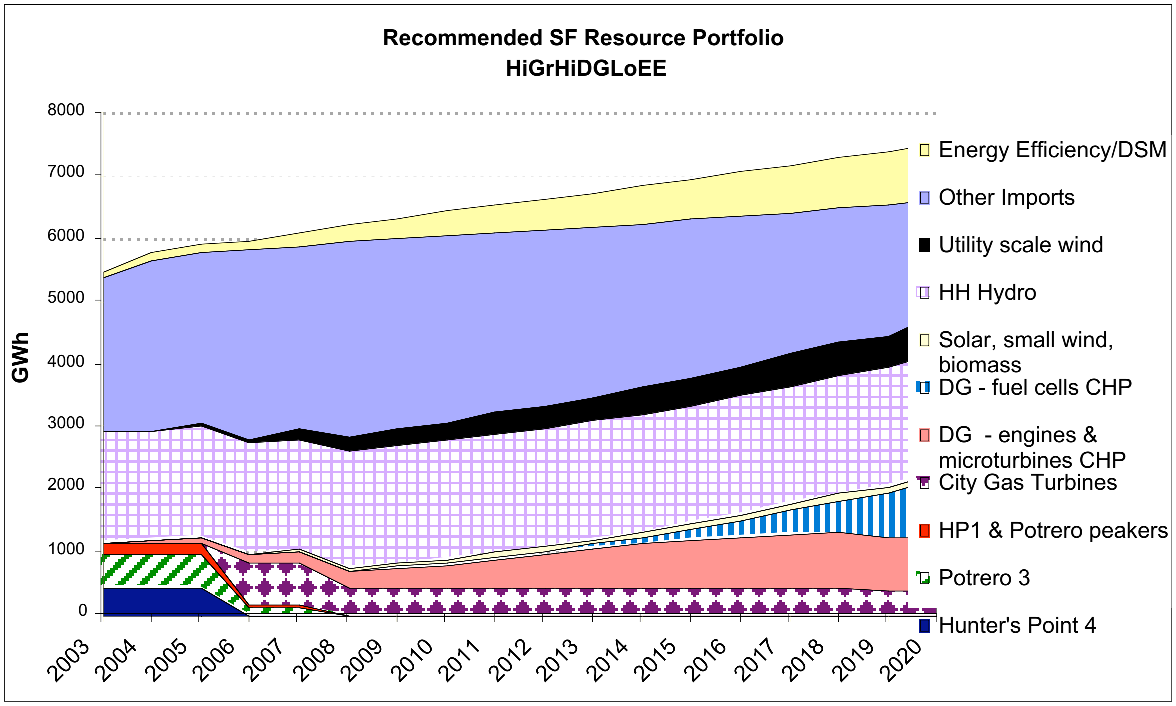


Figure 32. Resources to meet annual energy demand: high demand, high DG

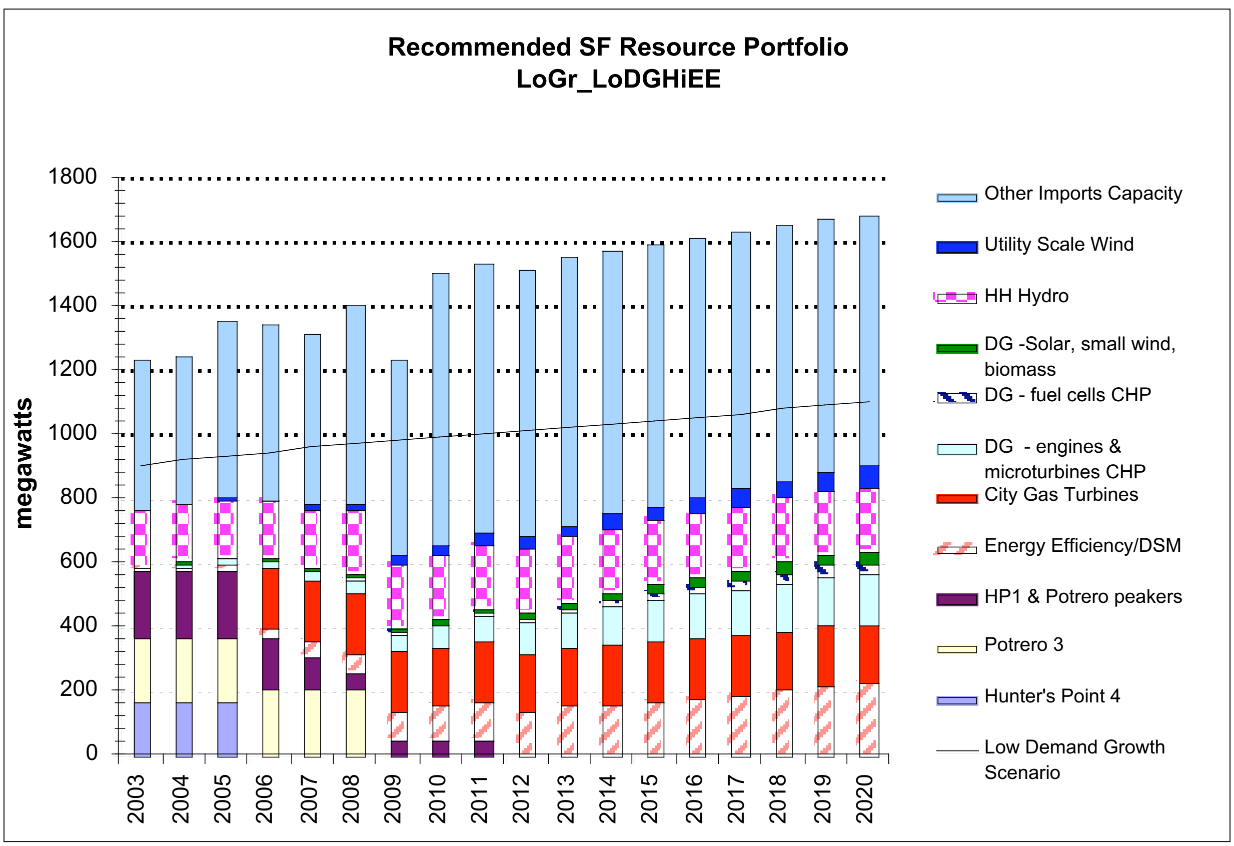


Figure 33. Resource portfolio to meet peak demand: low demand, high efficiency

In this scenario, the Hunters Point power plant is retired in 2005, and the Potrero plant is retired in 2011 (and the peakers earlier). Falling demand from aggressive energy efficiency programs free up enough supply resources to allow retirement of the new in-City CTs in 2020, but this scenario just barely satisfies our minimum in-City generation criterion for system reliability and stability. Thus, we are not confident that all central generation can be retired without the availability of low-cost fuel cells or a similar breakthrough in the cost and performance of renewable energy technology.

The results in terms of annual energy use and production are shown in Figure 6. With the reduced net demand level, in-City generation meets all net demand without operation of the old peakers, and Potrero unit 3 rarely runs above its minimum level of output. Distributed generation from combustion sources meets a modest share of demand, and renewable energy from in-City solar, remote wind farms and Hetch Hetchy hydro upgrades provide a similar amount of energy as in the high demand scenario, but meet a larger share of total City demand.

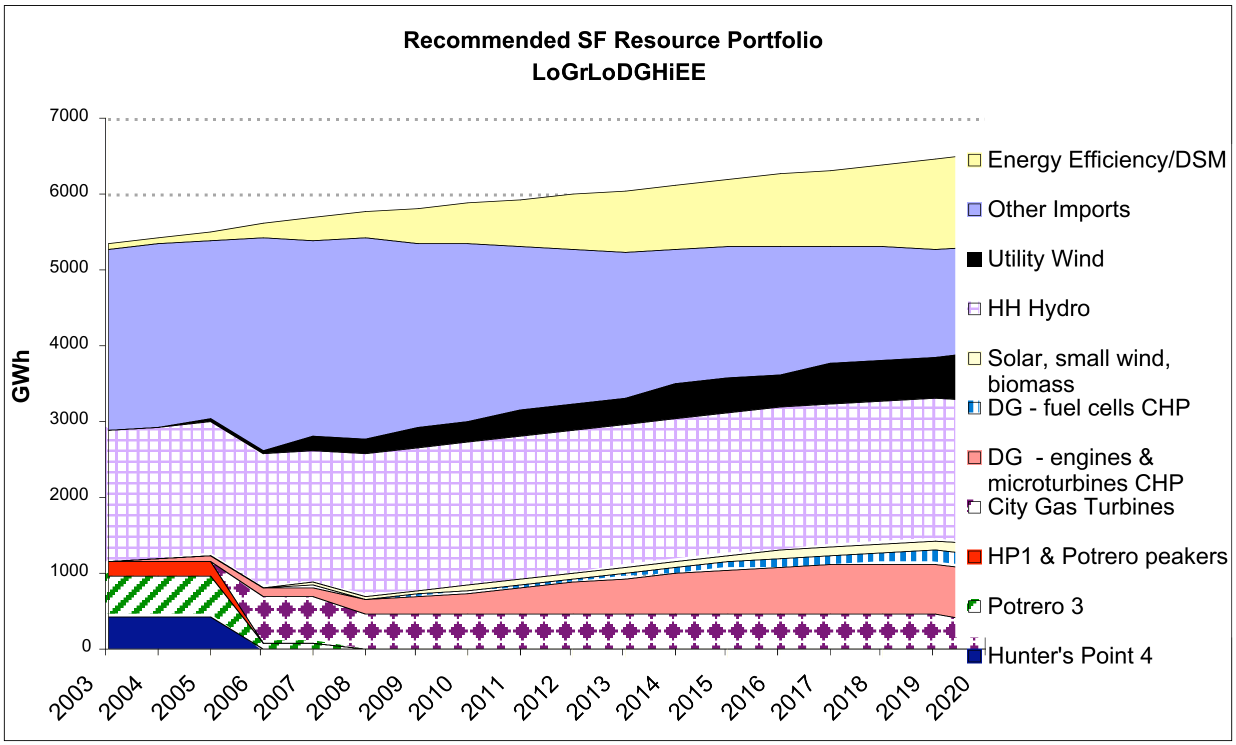


Figure 34. Resources to meet annual energy demand: low demand, high efficiency

Costs

One of the fundamental elements in the ERIS process is the comparison of costs for the various DSM and supply options and the selection of the options that minimize costs in the integrated strategy. For each energy supply or demand-side resource used in the scenarios, we estimate the generic capital costs, fuel costs and non-fuel operating costs for each technology.

Capital cost assumptions for the resource options are compiled from a variety of sources, including interviews with independent energy service providers, solar and wind equipment installers, CEC reports, and EPRI's Renewable Energy Technology Assessment Guide. Fuel costs for existing City resources (Hunters Point and Potrero), distributed generation including fuel cells, Peninsula generation, and imports are based on natural gas cost estimates discussed in the *Assumptions* section of this report. Operating costs include general operation and maintenance (O&M) costs, transmission charges, and credits (negative costs) for co-generated thermal energy. References for O&M cost assumptions include CEC's Comparative Cost of California Central Station Electricity Generation Technologies, consultation with the SFPUC, and other technology assessment reports.

Energy efficiency, load management and solar energy technologies are assumed to have negligible O&M costs, or no higher costs than the technologies that they replace. Capital costs of efficiency and DSM measures are assumed to follow a pattern of increasing marginal costs. In other words, it costs more to save 100 kW when the savings are 10% of the original load than when the savings are only 5% of the original load.

Depending on the degree to which a particular technology is deployed in a scenario, we assign the corresponding capital, fuel and operating costs to that scenario. Capital costs are assigned to the year in which the resource enters service (a simplification that ignores possible differences in construction lead-time), and fuel and operating costs are assigned to all years that the resource delivers energy services, in proportion to the energy services delivered. For each scenario, the costs of building and operating the various resources are summed to derive the total cost to the City each year.

In the following discussion, we highlight details of six of the long-term scenarios:
Case 1: High demand growth, moderate efficiency, low DG (high fuel cell costs)
Case 2: High demand growth, moderate efficiency, high DG (low fuel cell costs)
Case 4: High demand growth, high efficiency, high DG (low fuel cell costs)
Case 5: Low demand growth, moderate efficiency, low DG (high fuel cell costs)
Case 7: Low demand growth, high efficiency, low DG (high fuel cell costs)
Case 8: Low demand growth, high efficiency, high DG (low fuel cell costs)

Capital cost results

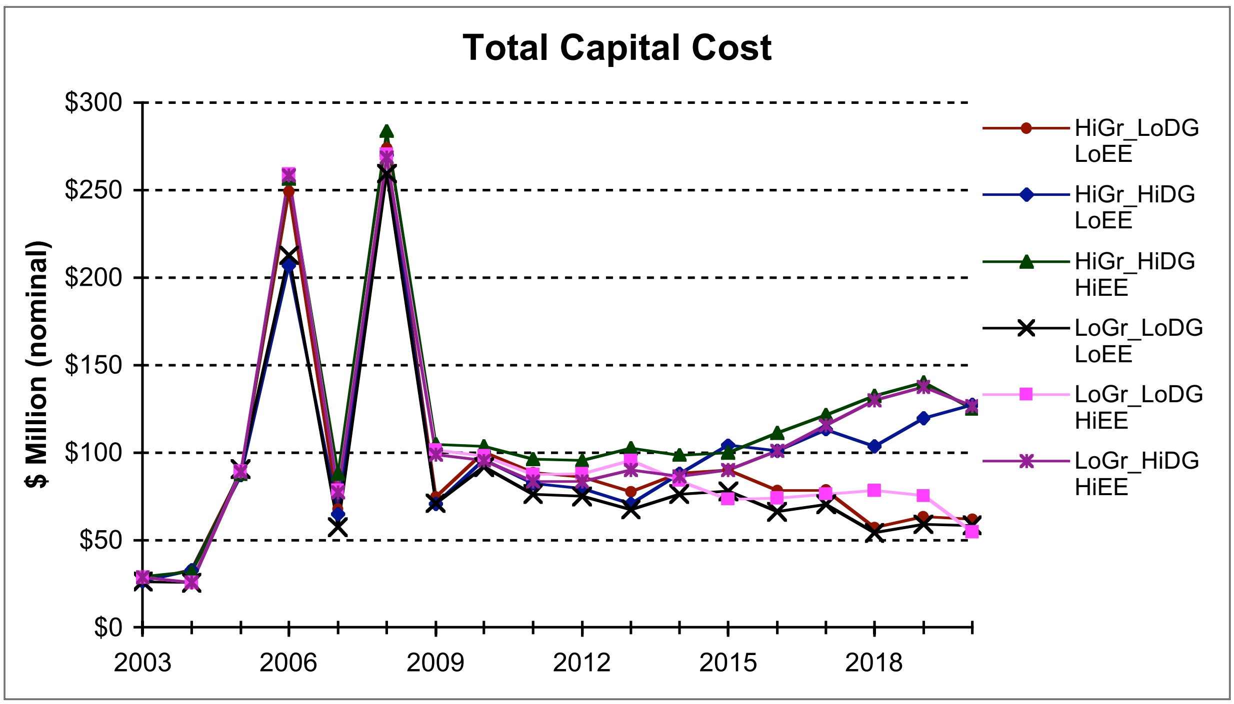
Figure 35 shows the future capital costs for DSM and supply side resource investments in six of eight scenarios explored for 2003-2020. Capital costs spike two times in years 2006 and 2008. The spikes represent the completion of the four in-City combustion turbines in 2006 and the completion of the Jefferson to Martin 230kV transmission line in 2008.

The capital costs stay relatively equal across the scenarios, with the high demand growth scenarios higher in cost than those of the low demand growth scenarios. This is due to the need for greater energy supply and efficiency investments in the high demand growth scenarios. Beginning in 2003-2005, capital costs include those of energy efficiency and distributed generation investments. We expect that DG and EE investments will not ramp up until at least 2005, and the capital costs thus remain relatively low at approximately $30 million per year.

Between 2009 and 2015, the capital costs among the scenarios stay fairly level, ranging from about $70 million in the low demand growth, low DG and moderate EE investment scenario (case 5) to about $100 million in the high demand growth, high DG and high EE investment scenario (case 4).

Beyond 2015, the capital costs among the scenarios diverge, with the scenarios calling for high DG, and high EE investments (cases 4, 8) rising above $100 million, and the low DG and low EE scenarios (cases 1,5) declining to approximately $50 million in 2020. This is due to the significant increase in stationary and mobile fuel cell units employed in the high DG scenarios.

Figure 35. Capital costs of selected scenarios, 2003 - 2020



In order to explore the financial implications of the cost scenarios, we categorized the investment costs according to the source of the investment. Figure 36 through Figure 41 give the capital cost breakdowns for each of the above scenarios. . The charts clearly show that the capital cost spike in 2006 is attributed to CCSF's investment in the construction of the four combustion turbines, and that the 2008 investment is PG&E's Jefferson-to-Martin transmission project.

The share of private sector investment can be seen to grow with time as the share of DG technologies increase in the high-DG scenarios. Although the private sector and the City share the investment costs of distributed generation, the private sector is assumed to be responsible for 70% of the capital costs. We assume that the City invests in both combustion technologies and fuel cells in the medium term (2006-2013), including demonstration projects, which sets the stage for a continuing commitment to fuel cell technology in the long term if fuel cell costs decline significantly.

Figure 36. Capital costs for high load, low DG, moderate EE scenario 2003-2020

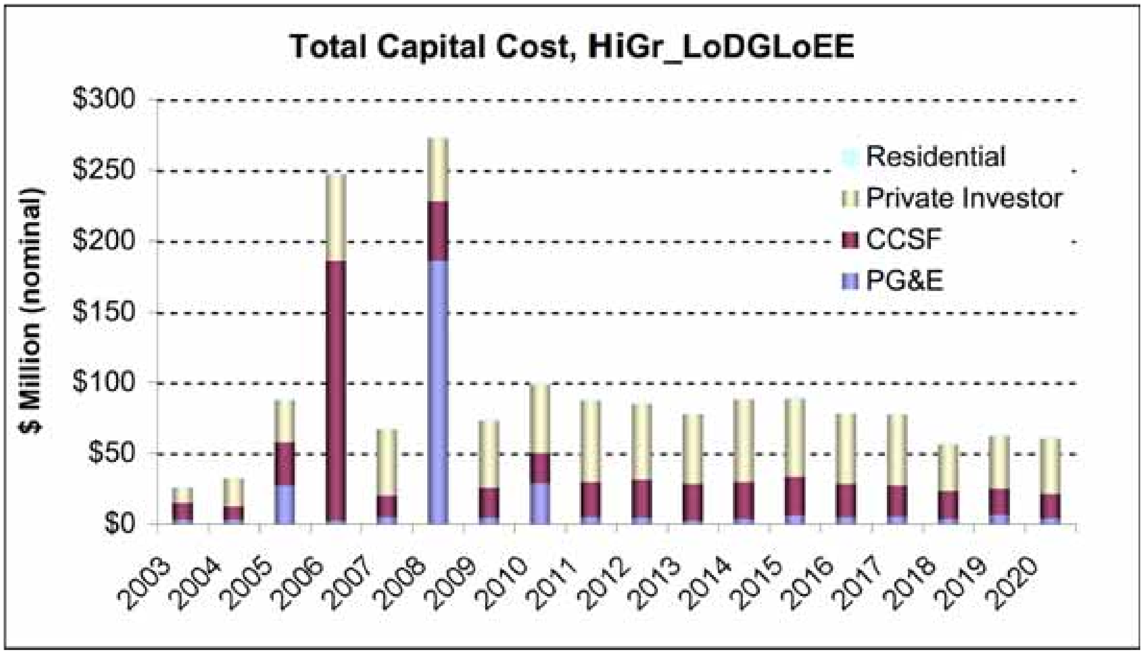


Figure 37. Capital costs for high load, high DG, moderate EE scenario 2003-2020

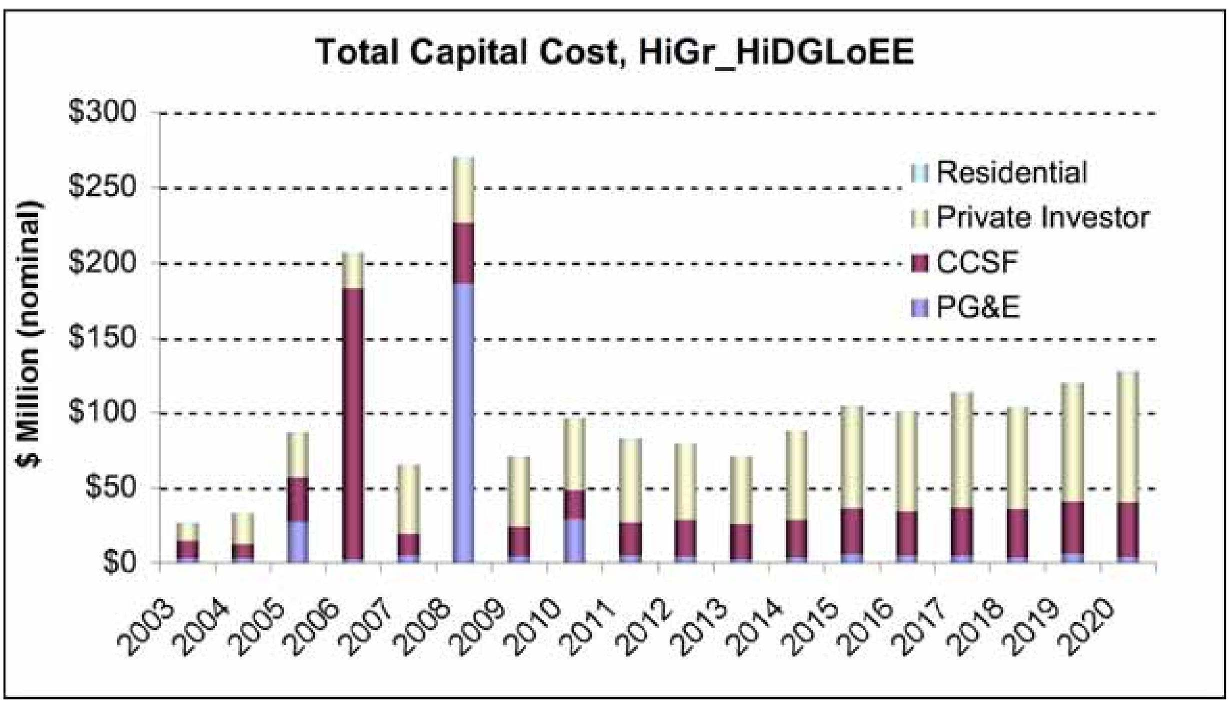


Figure 38. Capital costs for high load, high DG, high EE scenario 2003-2020

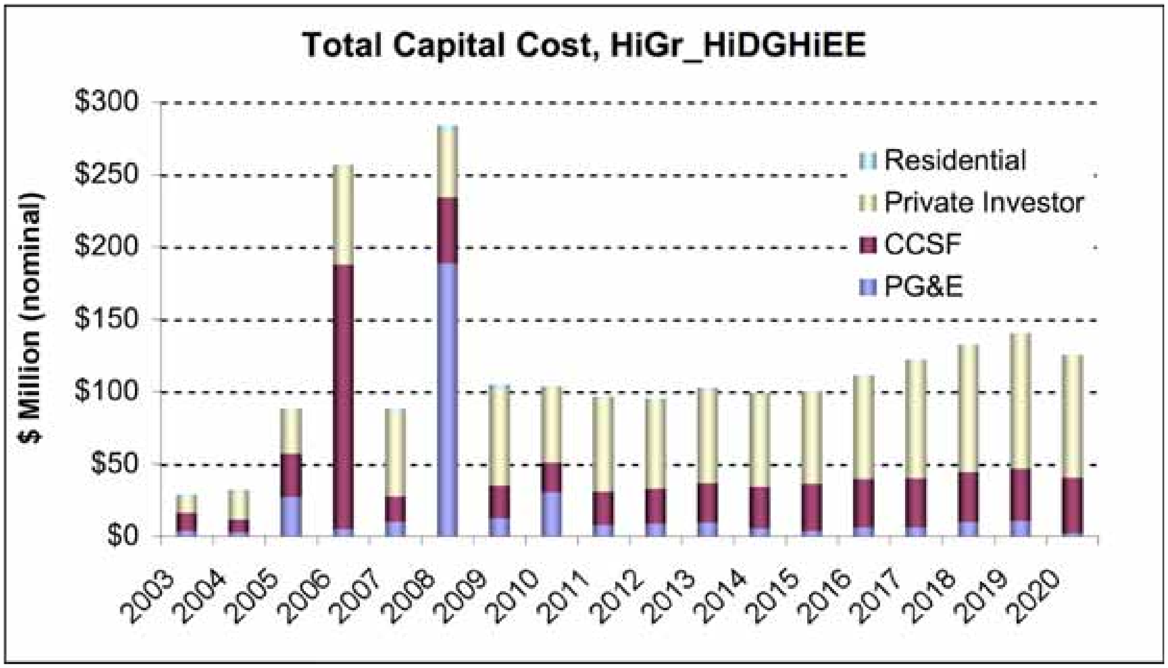


Figure 39. Capital costs for low load, low DG, moderate EE scenario 2003-2020

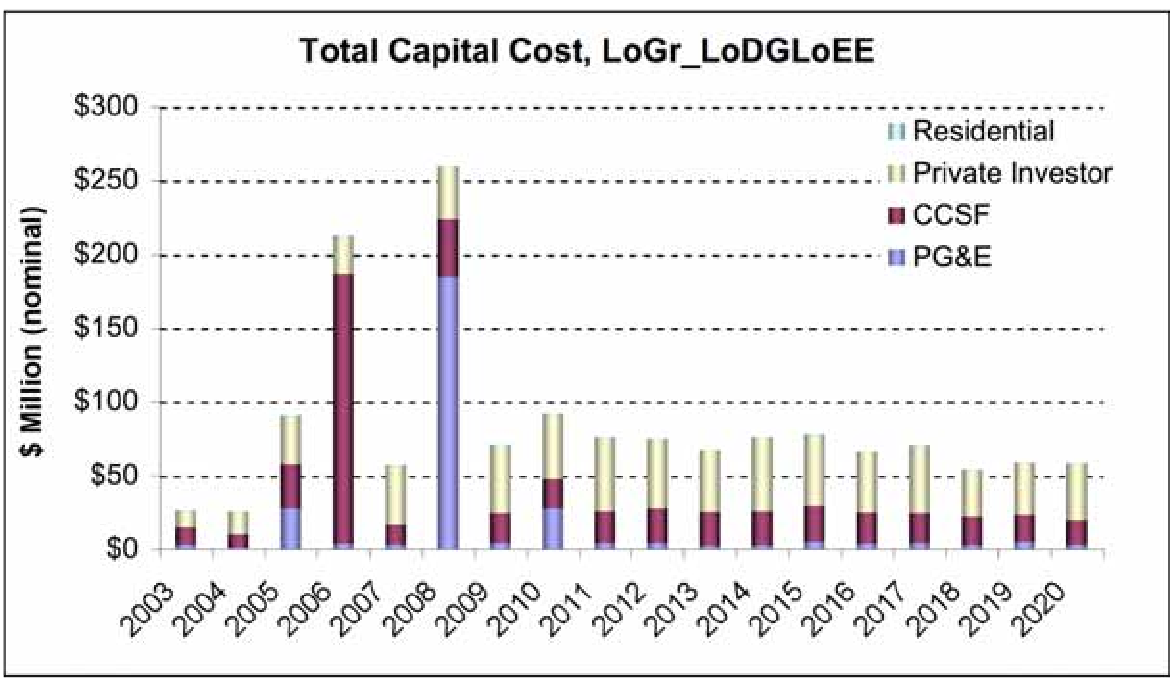


Figure 40. Capital costs for low load, low DG, high EE scenario 2003-2020

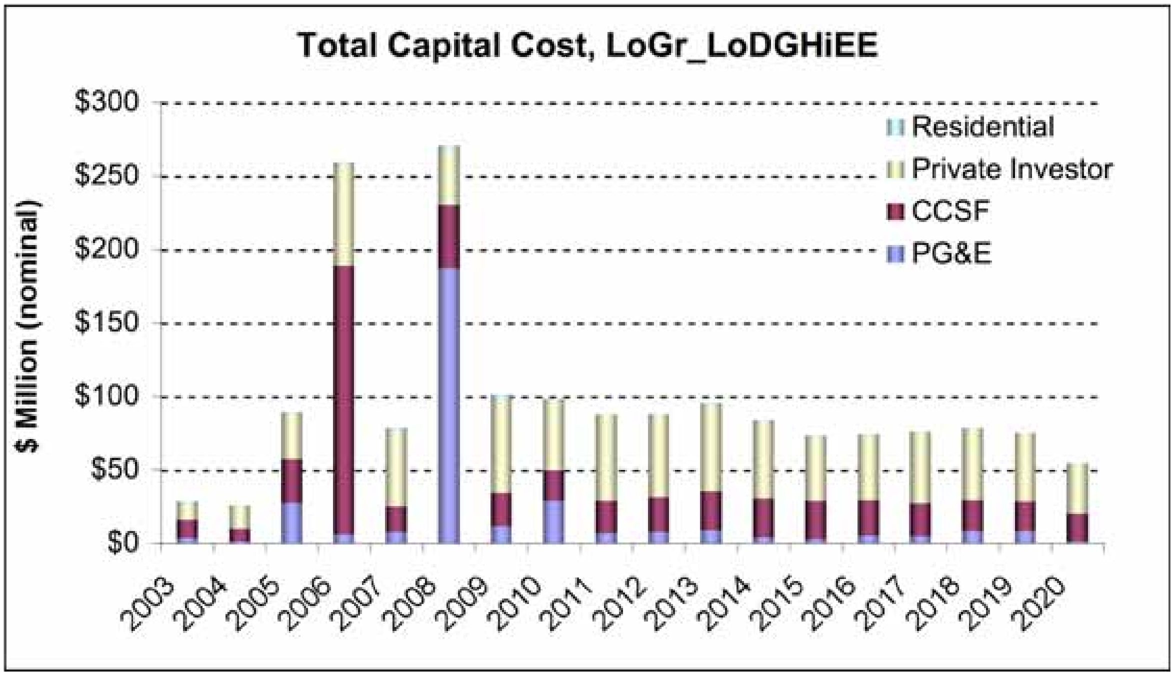
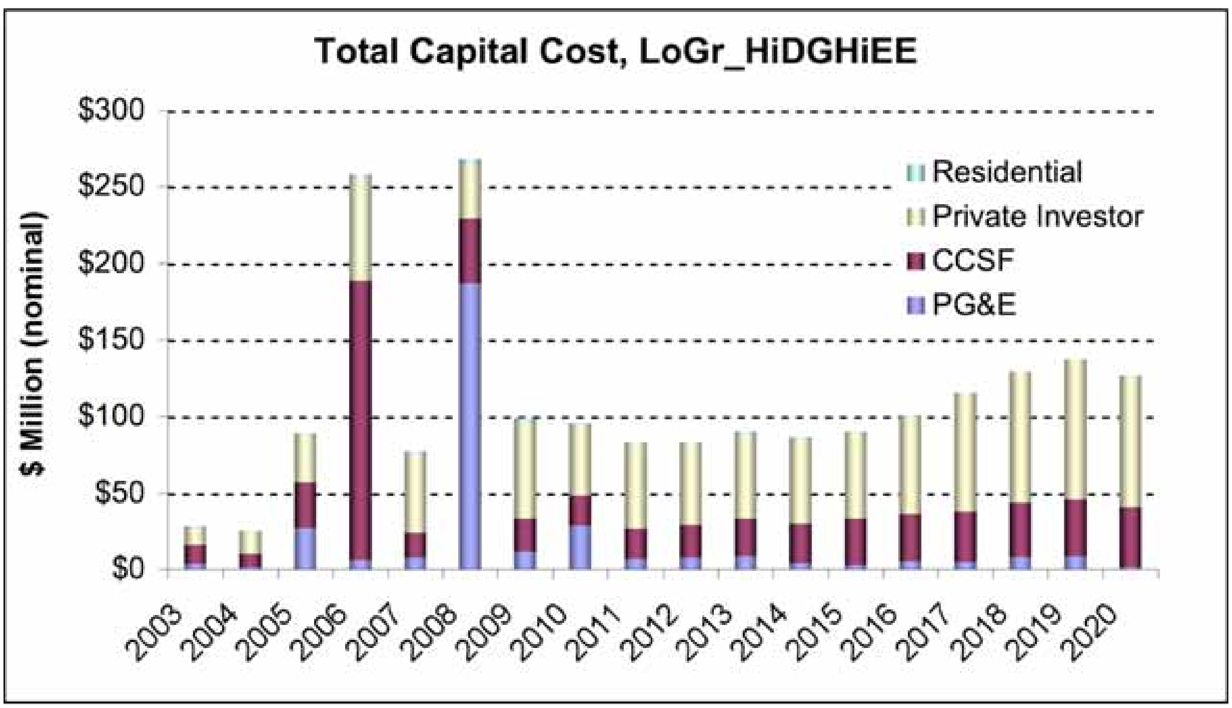


Figure 41. Capital costs for low load, high DG, high EE scenario 2003-2020



Capital costs of efficiency projects are assumed to be divided between the PG&E, residential consumers, the private commercial sector and the City. The private sector assumes the bulk of the responsibility for commercial projects, and CCSF assumes the bulk of the responsibility for municipal efficiency programs.

Purchased power, fuel, operation and maintenance costs

Annual operation and maintenance costs, including the cost of purchased power and fuel used for the supply resource options, are shown in Figure 42. Annual energy costs for high demand growth scenarios are greater for low demand growth scenarios. However, low DG and moderate EE scenarios (cases 1,5) have annual energy costs that are higher than scenarios with high in-City DG and high levels of EE investment (cases 4,8). This is explained by the cost charts below, in which the costs are segmented according to the investor. In summary, the annual energy costs are lower in scenarios where high levels of EE investments relieve the O&M and fuel cost burden of in-City central generation and imports, while aggressive DG further reduces the cost of purchased imports.

The annual energy costs for all scenarios begin in 2003 at approximately $270 million and gradually diverge with time. For the high demand growth, low DG and moderate EE scenario (case 1), costs grow gradually to a high of nearly $350 million by 2019. At the low range, the annual energy cost burden of the low demand growth, high DG and high EE investment scenario (case 8) gradually falls with time until dipping just below $200 million by 2020.

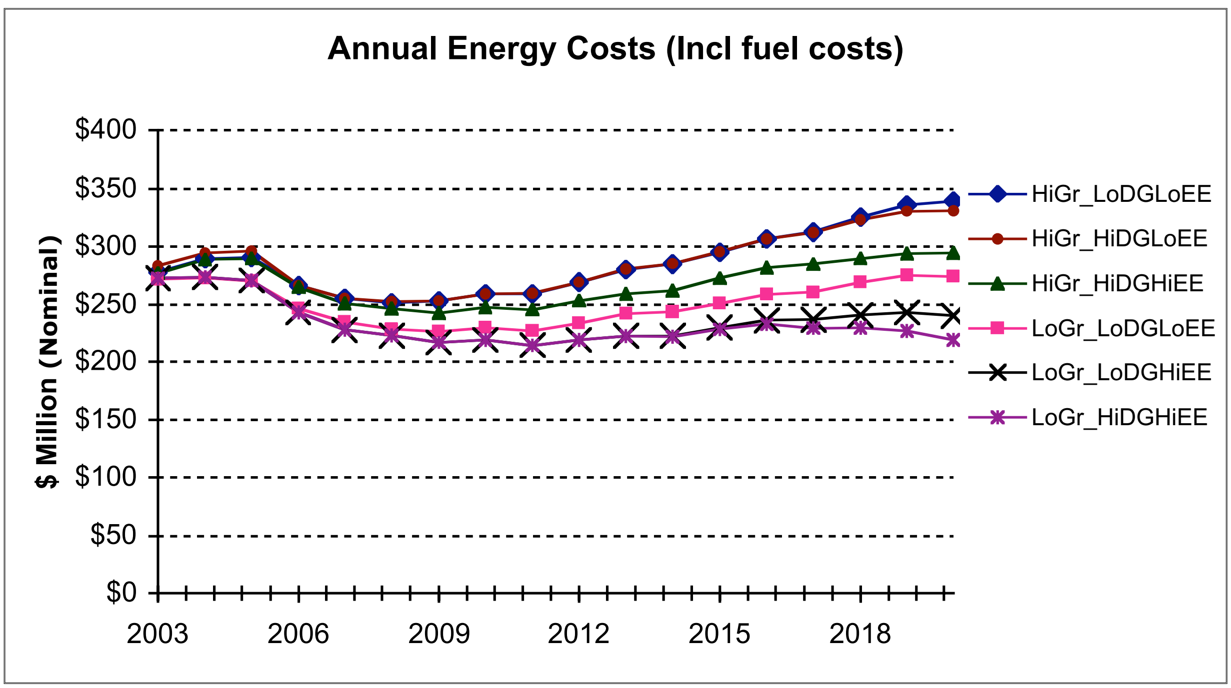


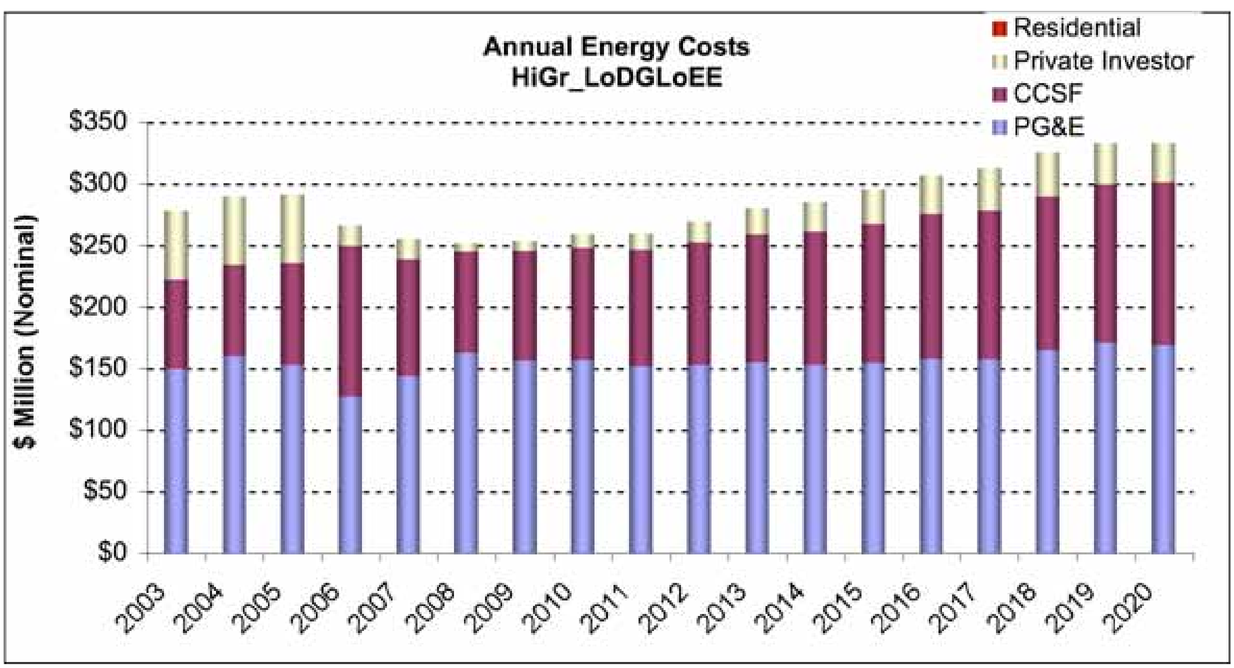
Figure 42. Annual energy costs, including fuel costs, for selected scenarios 2003-2020

Figure 43 through Figure 48 show the annual energy costs of various energy resource investments according to the investor for selected scenarios. Annual energy costs decrease for PG&E with the closure of Hunters Point and as the share of private sector investment in energy efficiency and DG increases. PG&E's total annual energy costs including fuel costs decline less significantly with low levels of investment in DG or with moderate efficiency investment, due to the greater need for imports into the City. Conversely, costs increase over time for private sector investors as the share of energy efficiency and private sector investment in DG increases.

The City's relative share of San Francisco's annual energy cost is seen to increase with time for all scenarios. Particularly as the total costs decrease with declining imports due to increased distributed generation and efficiency in San Francisco, the City's relative share of the costs increases. Furthermore, central generation investments such as the in-City cogeneration facility, the three gas-fired peakers the cogeneration facility at SFO, and the hydroelectric facilities at Hetch Hetchy become a substantial operations and maintenance (O&M) cost burden for the City.

We assume that O&M costs increase with the number of hours a plant operates each year, as well as with the age of the facility. The in-city cogeneration plant and the hydro facilities at Hetch Hetchy operate as baseload facilities year-round, and O&M costs increase as the facilities age. To the extent that energy efficiency and DG capacity reduces the need for the in-City peakers to operate, the O&M cost burden to the City also decreases. Comparing the annual energy costs across the scenarios (Figure 43 through Figure 48), we see that the City's costs decline with increased EE or DG or both.

Figure 43. Annual energy costs for high load, low DG, moderate EE scenario 2003-2020



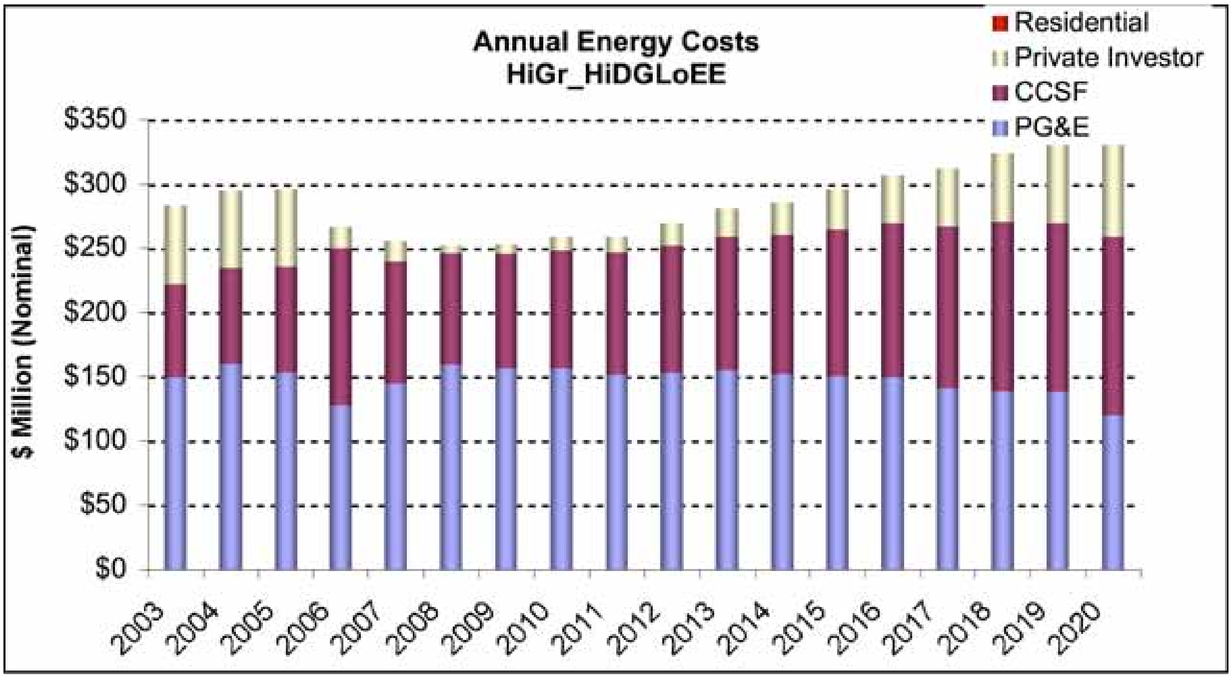


Figure 44. Annual energy costs for high load, high DG, moderate EE scenario 2003-2020

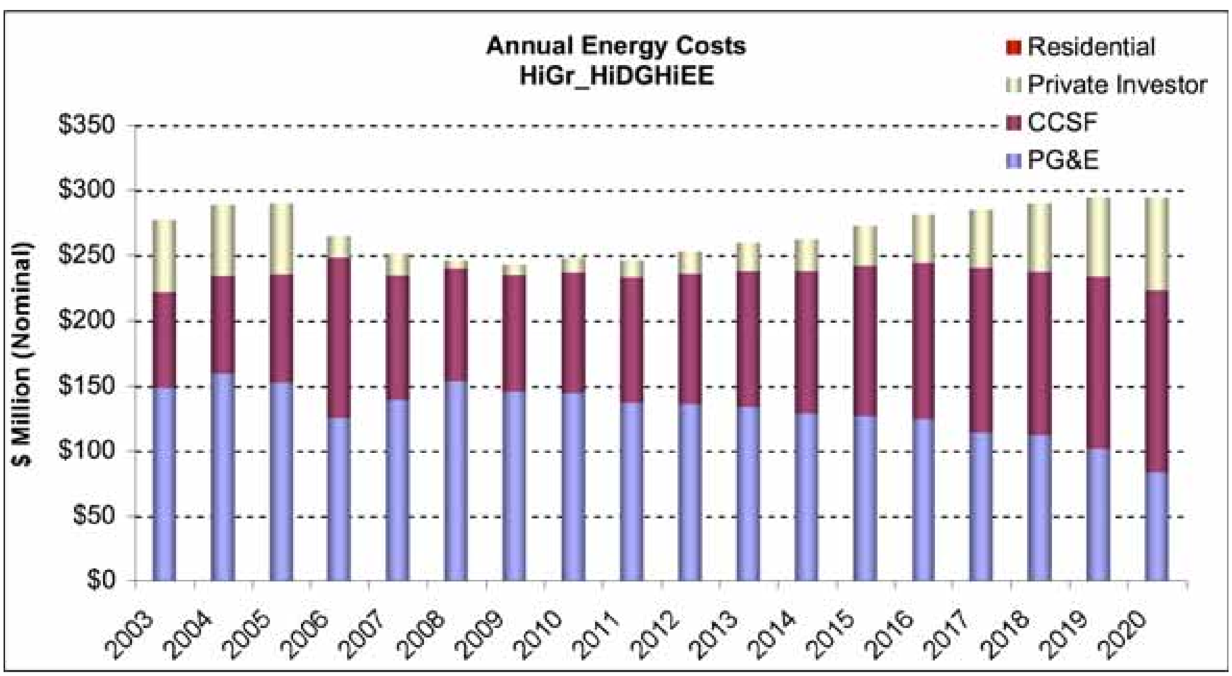


Figure 45. Annual energy costs for high load, high DG, high EE scenario 2003-2020

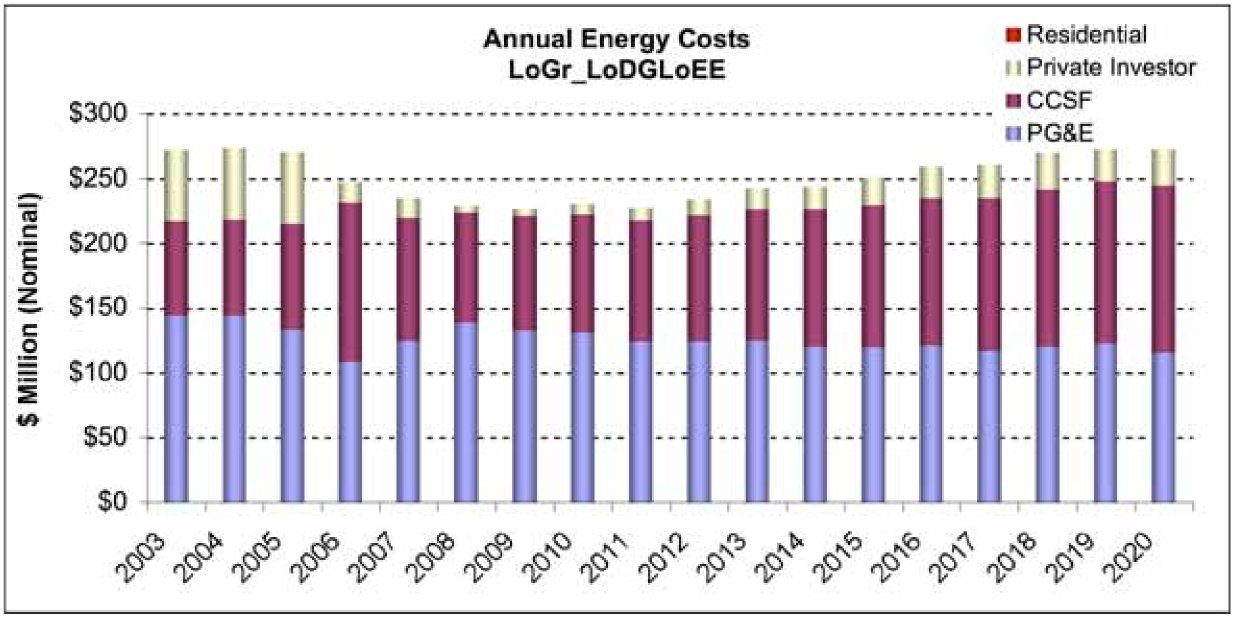
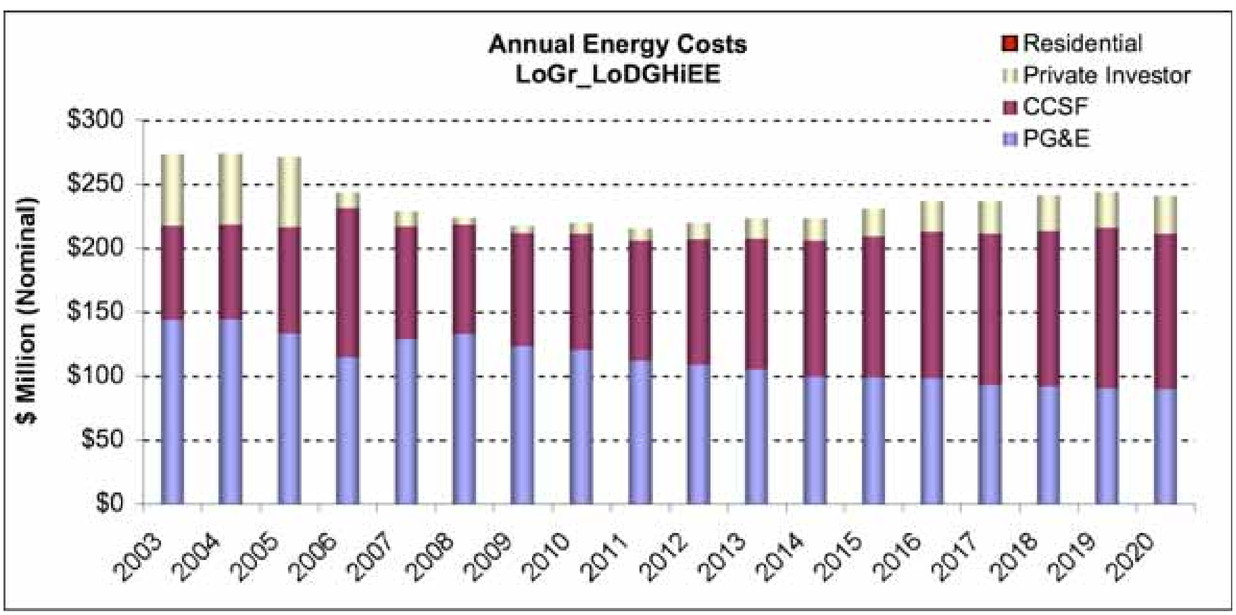


Figure 46. Annual energy costs for low load, low DG, moderate EE scenario 2003-2020

Figure 47. Annual energy costs for low load, low DG, high EE scenario 2003-2020



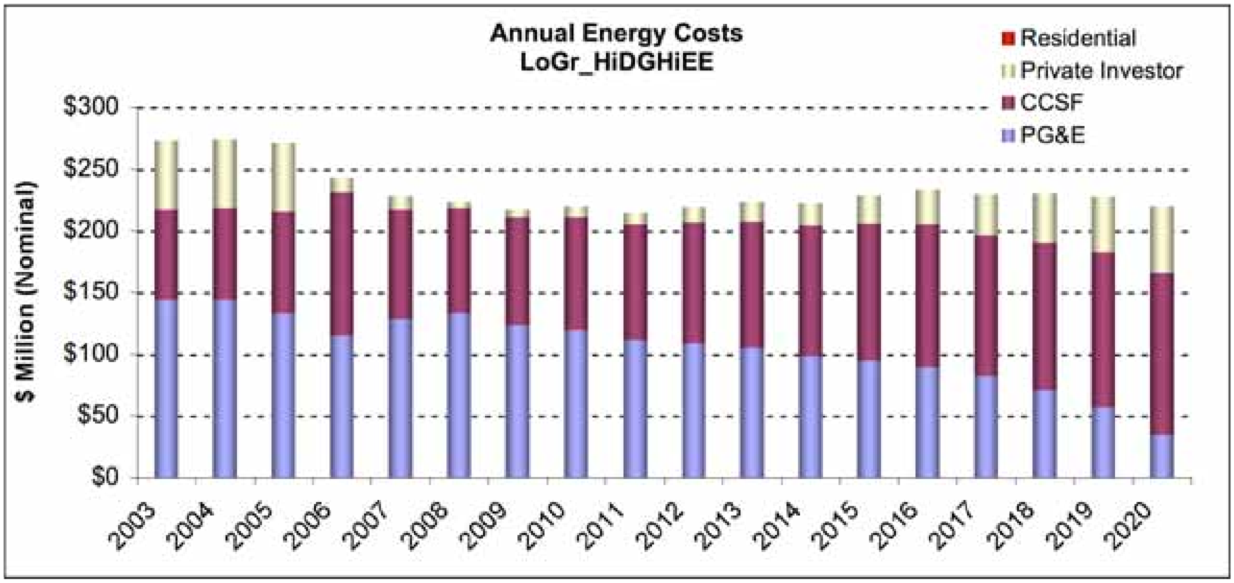


Figure 48. Annual energy costs for low load, high DG, high EE scenario 2003-2020

Total annualized cost

The total annualized cost of the scenarios studied is the sum of the annualized capital costs and the annual energy costs described above. The results are shown in Figure 49. Costs increase over time, due to inflation and the increase in demand for energy services. Note that the level of energy services increases in all the scenarios, even if net growth in electricity demand is slow or negative, because an increasing share of the energy service demand is met via energy efficiency measures. The main difference between the scenarios is that costs are higher in the scenarios with high growth in baseline demand, compared to the load load growth scenarios.

The overall results for the scenarios are shown in terms of the total cost per kWh of energy services delivered in Figure 50. The total annualized costs (annual operating cost plus annualized capital costs) are divided by the total energy service demand (energy supplied *plus energy saved*) to arrive at a total cost normalized per kWh. Note that this cost level is far below the current retail commercial electricity tariffs in San Francisco. This is because the historical costs of the existing power supply and delivery system, including costs incurred during the recent power crisis, expensive power purchase contracts, and earlier generation plant cost overruns, are still included in the utility rate base that determine power prices in California.

Because we have calculated costs in nominal dollars, which include an assumed inflation rate of 1.5%/year, the total cost per MWh would be expected to increase from 5.25 c/kWh to about 6.75 c/kWh without any change in real costs. In fact, the total cost of delivering each unit of energy services does not increase significantly above inflation in any of the scenarios. In the high demand growth scenarios, total costs increase slightly above inflation, while costs in the low demand growth scenarios increase a little slower than inflation.

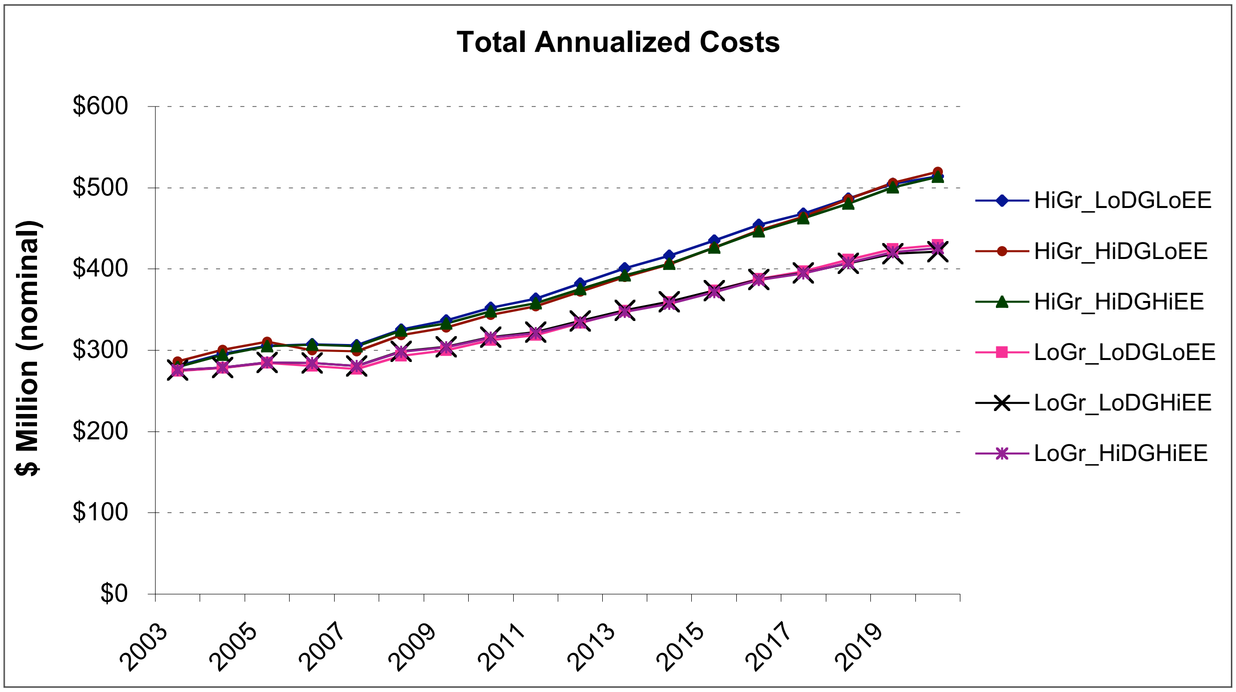


Figure 49. Total annualized costs for selected scenarios

The difference in overall cost between the high load and low load scenarios reflects the least-cost planning approach taken under the ERIS methodology. Because the high demand growth scenarios require additional resources compared to the low demand growth scenario, higher cost resources must be employed at the margin, thus increasing costs somewhat. These expensive marginal resources can include purchased power imports, additional DG in the City, and some additional, relatively high-cost energy efficiency measures, depending on the specific scenario.

Note that the costs in the high-DG scenarios reflect a significant reduction in the cost per kW of a number of renewable and distributed generation technologies, including solar PV, wind, high- and low-temperature fuel cells (including V2G). These are relatively new technologies, although the renewable energy technologies are widely used throughout the world, and their costs are therefore less certain than the costs of more mature technologies. Although wind turbine technology has matured to the point where generation costs are competitive with conventional sources, costs are still falling steadily, and it is reasonable to expect significant cost reductions in the future. Costs of the other technologies will fall as they mature and expand their markets. Any cost breakthroughs in these technologies would make our capital cost estimates conservative.

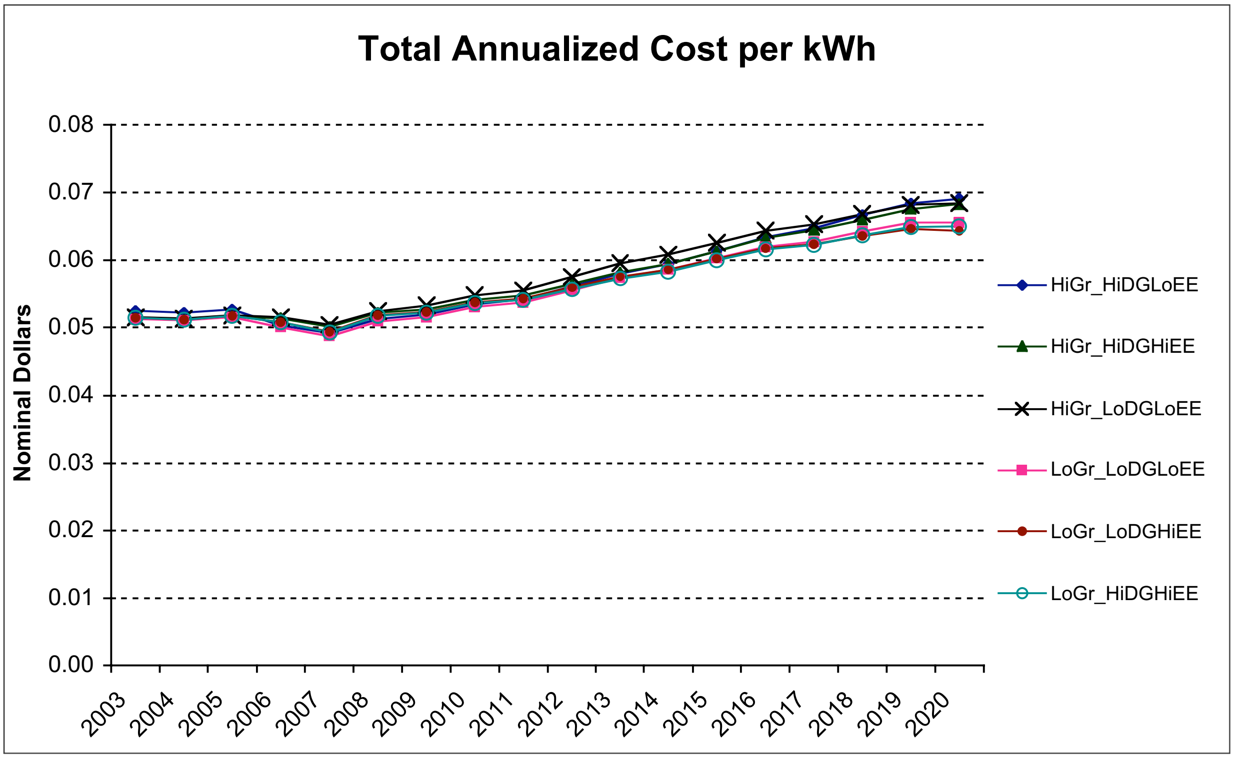


Figure 50. Total annualized cost per kWh of energy services for selected scenarios

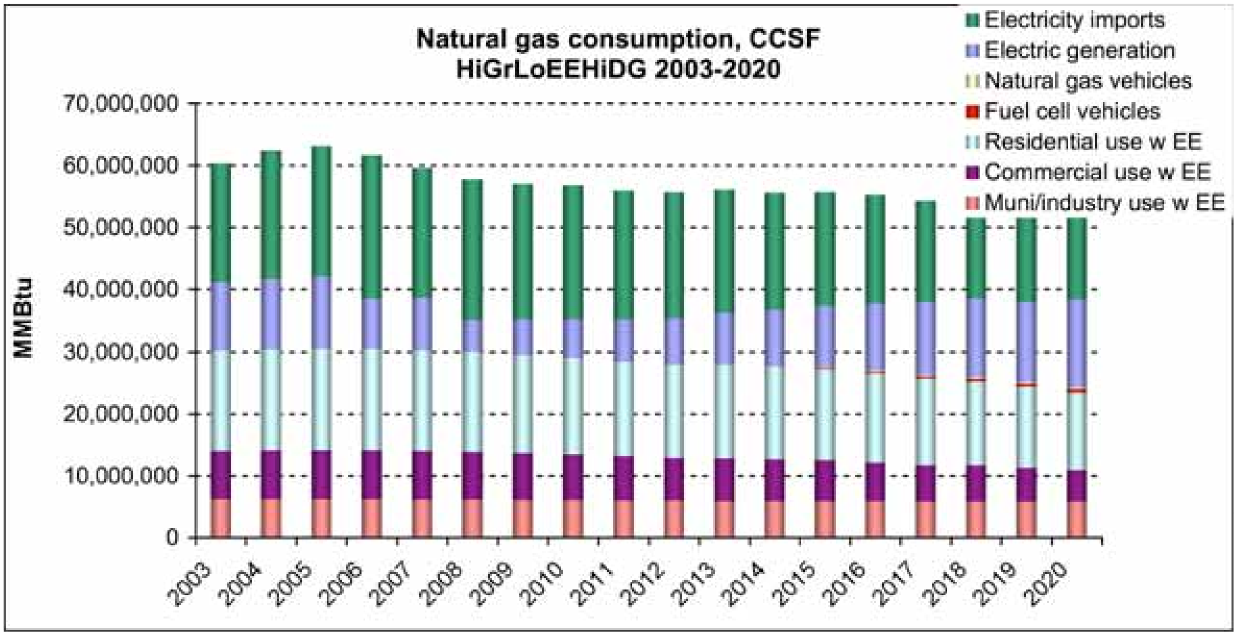
Natural Gas Use

Although most of the challenging energy planning issues that San Francisco faces are related to the electricity system and its potential supply constraints, the ERIS process takes other energy carriers into account. Thus, we also consider the natural gas supply and usage implications of the ERIS electricity portfolios, in order to identify the potential conflicts, synergies and opportunities that are revealed by the interactions between the natural gas and electric energy systems.

With additional in-City generation planned, and an emphasis on gas-fired DG in some scenarios, San Francisco risks excessive reliance on new natural gas supplies. However, our analysis shows that using electricity and direct natural gas more efficiently, together with the inherently higher efficiency of new generation technology and distributed co-generation, results in no long-term increase in total City gas demand under all the scenarios.

Total City gas use, including direct use in the residential and commercial sectors, is shown in Figure 51 for the highest demand scenario: high demand, moderate efficiency, high DG (case 2). Figure 52 shows the results for a low demand growth scenario (case 5). Even in the high-demand scenario, total gas use to meet City energy demand, which includes the generation of power the City imports, falls gradually after a small initial increase. Although this high-DG scenario causes the highest demand for gas within San Francisco, in-City gas demand (all of the demand *except* that for power imports) remains below current levels throughout the duration of the scenario.

Figure 51. Total natural gas use to meet City energy demand, high demand scenario



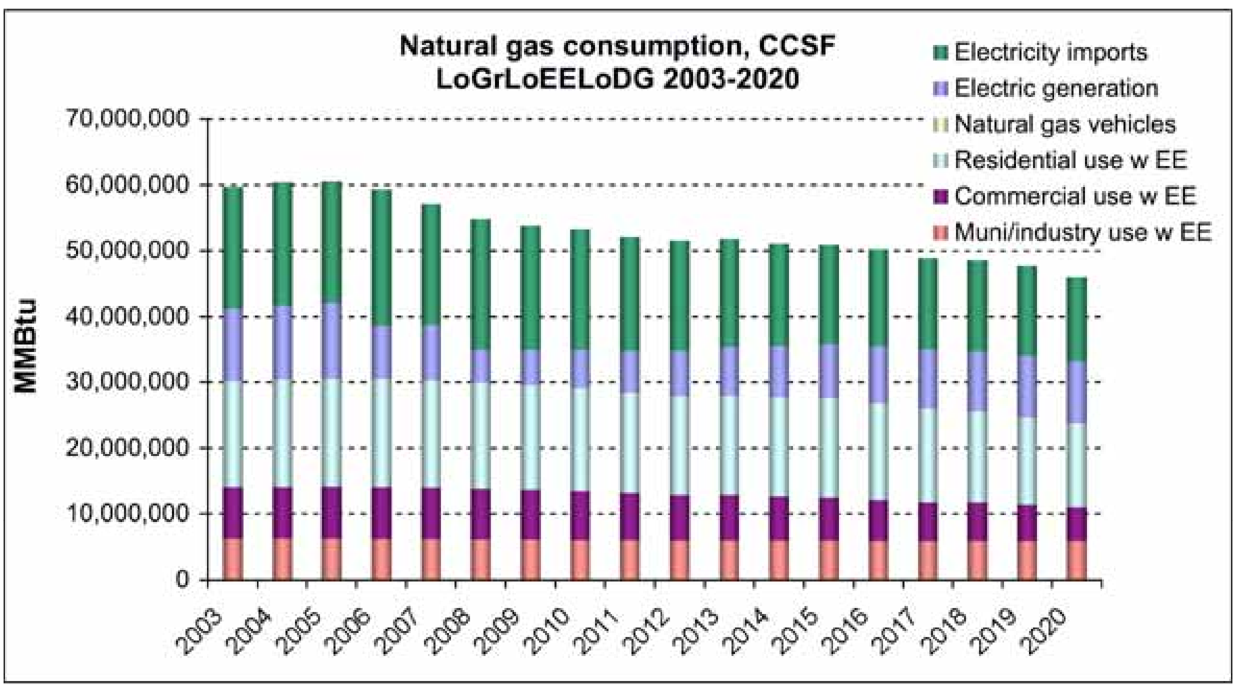


Figure 52. Total natural gas use to meet City energy demand, low demand scenario

Thus, we expect *little difficulty in meeting the City's natural gas supply needs* in any of the scenarios. Although the growth of DG, including fuel cells and V2G generation, adds to gas demand, the high efficiency of these technologies and their coupling with co-generation mitigate their fuel needs. The fuel consumption impact from 15,000 fuel cell vehicles and V2G generation is relatively small. In the low demand scenarios, total and in-City gas use is lower still.

Reliability and Reserve Margin

One of the underlying trends assumed in all the scenarios is the growing demand for high electric supply reliability. Premium reliability can have a high value in sensitive industries such as data centers, as well as many conventional businesses. These businesses are not simply inconvenienced by a power outage; they can be crippled by even a brief outage.

Contrary to some widely cited claims, the demand for premium reliability does not necessarily translate into large increases in the total electricity demand, because each generation of electronic equipment is ever more energy-efficient, and because electronic commerce reduces the need for other, more energy-intensive activities such as transport.[57] However, the number of customers that need premium-reliability power and are willing to pay for it will continue to grow in response to economic needs and heightened concern about energy security.

This analysis considers mostly the generation and transmission components of the electricity supply system. Because the majority of electric outages is caused by faults in the distribution system, from interference by trees, animals, cars, etc., rather than by generation, we cannot fully assess reliability issues in detail here. We do, however, evaluate the adequacy of the generation and transmission system to deliver power to San Francisco, In addition, we consider the conditions that would have to be met in order to take advantage of the increase in DG technology to provide improved customer reliability.

To assess the reliability of the generation and transmission systems in the scenarios, we consider three different metrics:

- Overall reserve margin, the difference between total supply resources and maximum demand under double first contingency criteria (generation and transmission)
- Net transmission capacity to import power into the City under first contingency planning criteria
- Total in-City generation capacity to serve City loads without imported power.

[57] Technically consistent estimates based on real measurements show that all office, communications and networking equipment account for about 3% of U.S. electricity demand, and that its growth is largely offset by continuous efficiency gains. Kawamoto, K., et al., 2001. *Electricity Used by Office Equipment and Network Equipment in the U.S.*, Lawrence Berkeley National Lab, LBNL technical report number 45917. See http://enduse.lbl.gov/projects/infotech.html for a review of the whole debate. For a summary of energy efficiency gains from the Internet, see www.cool-companies.org/energy.

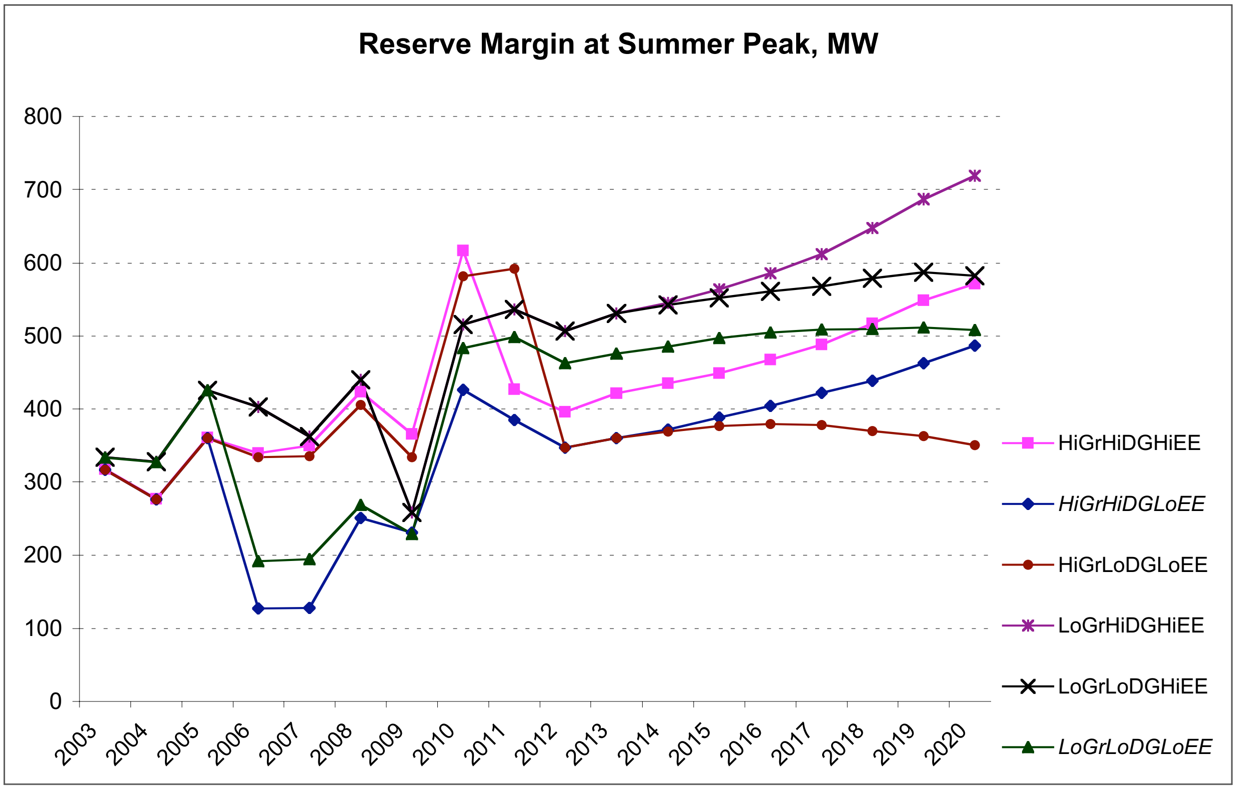


Figure 53. Reserve margin (MW) at summer peak under first transmission contingency

We define the reserve margin to be simply the margin above the peak demand level that can be supplied by the sum of all available supply resources, including generation and transmission. For this calculation, our system boundary is the Martin substation. Loads in the City reduce the reserve margin, while generation resources and peak-coincident DSM resources increase the reserve margin. Additional reserve margin is provided by the transmission capacity into the City, which limits the imports of all outside power sources, including those owned by San Francisco.

The principal method of measuring the adequacy and reliability of the power supply system is to consider the reserve margin, which is the amount that the total in-City generation capacity, together with the transmission import capacity, exceeds the summer peak demand (net of energy efficiency savings) under first contingency criteria. Figure 53 shows the reserve margin based on the transmission capacity under first contingency criteria. To satisfy the double first contingency criteria (transmission and generation), the reserve margin value shown in Figure 53 must be greater than the capacity of the largest in-City generation unit.

As long as Potrero unit 3 is in service, this value must be more than 207 MW. After both Hunters Point and Potrero unit 3 have been retired, the largest unit will be a combustion turbine peaker with a capacity of about 50 MW, so the reserve margin value only needs to be greater than 50 MW. Figure 53 shows that the reserve margin is adequate in all scenarios. In two of the scenarios shown, the reserve capacity value slips below 200 MW in 2006-2007. This is because we used these two scenarios to illustrate the effect of not retrofitting Potrero unit 3. Although the reserve margin is reduced in these two scenarios, it is still adequate, because the required reserve margin value drops to about 50 MW with unit 3 derated, and it remains at about 50 MW in the future.

Thus, there appears to be adequate transmission and in-City generation capacity to meet the summer (and winter) peak demand in all scenarios. Satisfying this reliability criterion does not necessarily ensure that system stability will be adequate. To date, an additional reliability criterion has been used, the San Francisco Operating Criterion, which requires in-City generation with a capacity at least equal to 40% of the City load, which corresponds to the high-value "downtown network" load.[58] This currently requires about 380 MW of generating capacity, which is met by the two steam plants at Hunters Point and Potrero.

Operating reliability criteria for the greater Bay Area can also affect the need for capacity in San Francisco. The RMR contract for Potrero unit 3 is required by the CAISO partly because it provides supply capacity to San Francisco within the Peninsula transmission constraint, but also because it enhances the stability of the greater Bay Area transmission grid. Moreover, CAISO has informed the City that unit 3 is several times more effective in terms of the Bay Area's load-serving capacity than generation at, for example, Pittsburg or Antioch. Thus, the CAISO expects unit 3 to continue running as an RMR unit until other generation is developed on the Peninsula or other transmission upgrades are developed to add import capability into the Bay Area.[59]

In the future, therefore, it is uncertain what capacity additions the CAISO will require before ending the RMR contract for Potrero unit 3; if and how the San Francisco Operating Criterion will be used; and what role distributed generation will play in meeting reliability needs in the City. However, we expect that electric distribution control and communication technology will improve, such that it will become simpler to connect DG sources in a way that enhances, rather than handicaps, the grid's performance. Therefore, we assume the DG will be able to contribute to meeting the future reliability criteria, and that central generation in the City can eventually be replaced. Note, however, that this idea is probably contrary to the present CAISO position, if it has even been considered, and that it is uncertain if and when they would accept this position.

As a simple compromise criterion, we assume a minimum of one-third of the City's peak load (after efficiency savings) must continue be met by in-City generation including DG. This translates to about 350 MW of generation in most scenarios. As shown in Figure 54, this criterion is met in all the scenarios. The share of peak City load met by in-City generation dips below 40% in the years after Potrero unit 3 is closed or derated. However, the addition of DG raises this ratio above 40% in later years.

[58] Environmental Science Associates, 1998. *Draft Environmental Impact Report for Pacific Gas and Electric Company's Application No. 98-01-008*, section 4.12.
[59] Ed Smeloff, SFPUC, personal communication, 26 September 2003.

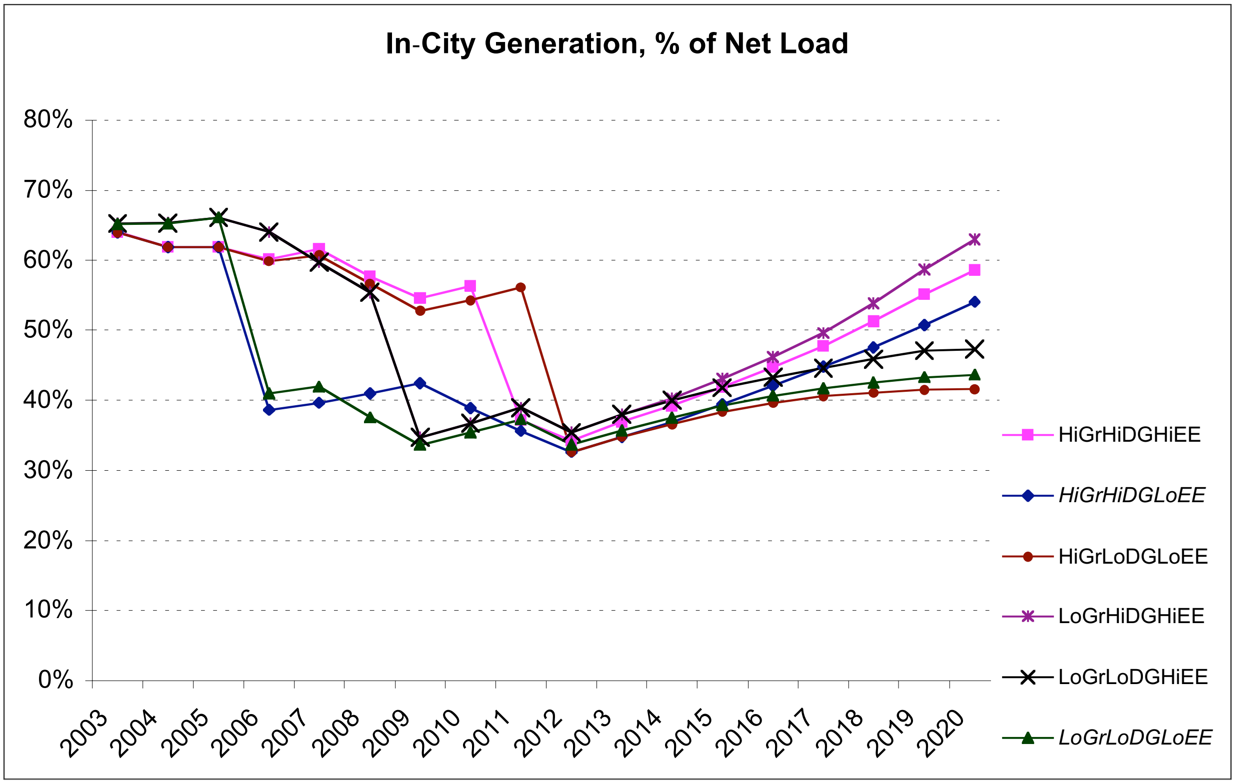


Figure 54. Total in-City generation (including DG) as a share of peak demand (net of DSM)

Emissions

The City of San Francisco's environmental health is vulnerable to several risks. Low-income communities are particularly impacted by local air pollution from the City's old, inefficient power plants such as Hunters Point. The need to close this plant, reduce emissions from the remaining generators at Potrero, and otherwise improve the environmental quality and equity within the City is an important motivation for producing an ERIS.

While oxides of nitrogen and other air emissions are a major health issue to many citizens and a serious local pollutant, global environmental concerns are becoming increasingly timely. San Francisco Mayor Willie Brown recently called for a 20% reduction in CO_2 emissions in 2010, compared to 1990 emission levels. Emissions of CO_2 come predominantly from the use of fossil-fuel energy sources. Thus, electricity production is a major source of CO_2 emissions and a key target for future emission reductions via energy efficiency and cleaner sources.

This analysis uses generic emission intensities for the various technologies included in the scenarios to estimate the sources of NOx and CO_2 emissions in each scenario and to compare the overall emissions levels in the scenarios.

Emissions are calculated based on the quantity of energy (MWh) produced from each source. Energy savings from efficiency and DSM produce no emissions. The total emissions from each energy source is estimated as its emission intensity multiplied by the MWh of electricity produced using that technology.

Near-term reductions compared to present emission levels

Air pollution and greenhouse gas (GHG) emissions are produced by fossil fuel-fired generation and industrial equipment in the City. Currently, the largest stationary sources of air pollutants in San Francisco are the Hunters Point and Potrero plants. The local pollutants of most concern are oxides of nitrogen (NOx), one of the causes of smog, and small particulates less then 10 microns in diameter (PM10). Carbon dioxide (CO_2) is the primary contributor to global climate change.

Thus, displacement of older, less efficient and more polluting power plants is one of the most effective means of improving air quality in San Francisco. By enabling the closure of the Hunters Point plant, the proposed new combustion turbines, with their state-of-the art gas turbine technology, will greatly improve San Francisco's air quality. They are 20-30% more efficient than Potrero unit 3 and Hunters Point unit 4, and 40% more efficient than the existing peaking gas turbines. Additionally, their state-of-the-art emissions control systems will lower NOx emissions to 2.0-2.5 ppm as required by the BAAQMD.

The proposed cogeneration plant, which would generate steam for the downtown steam loop, provides another opportunity to displace pollution sources. The existing boilers, which operate around the clock, produce approximately 20 ppm of NOx. By using one of the new combustion turbines for cogeneration to displace part of the steam production of these boilers, the City can eliminate approximately 10 tons per year of NOx, equivalent to about half of the NOx emissions of a new combustion turbine.

Table 10 compares the emissions of the existing thermal power plants with the new gas combustion turbines. The least efficient and most polluting technologies are clearly the existing Hunters Point and Potrero power plants. The retrofit of Potrero unit 3 does not reduce CO_2 emissions, because the plant efficiency would not improve significantly, but it does reduce NOx emissions by 75-80%. On the other hand, the new City-owned CT generation plants have lower emissions than the existing plants.

The emission values for purchased imports are averaged values from all of the generating resources available in California. Note that the emission rates for power supplied region-wide in the Western U.S. would be much higher, because of the dominance of coal in the regional generation mix.

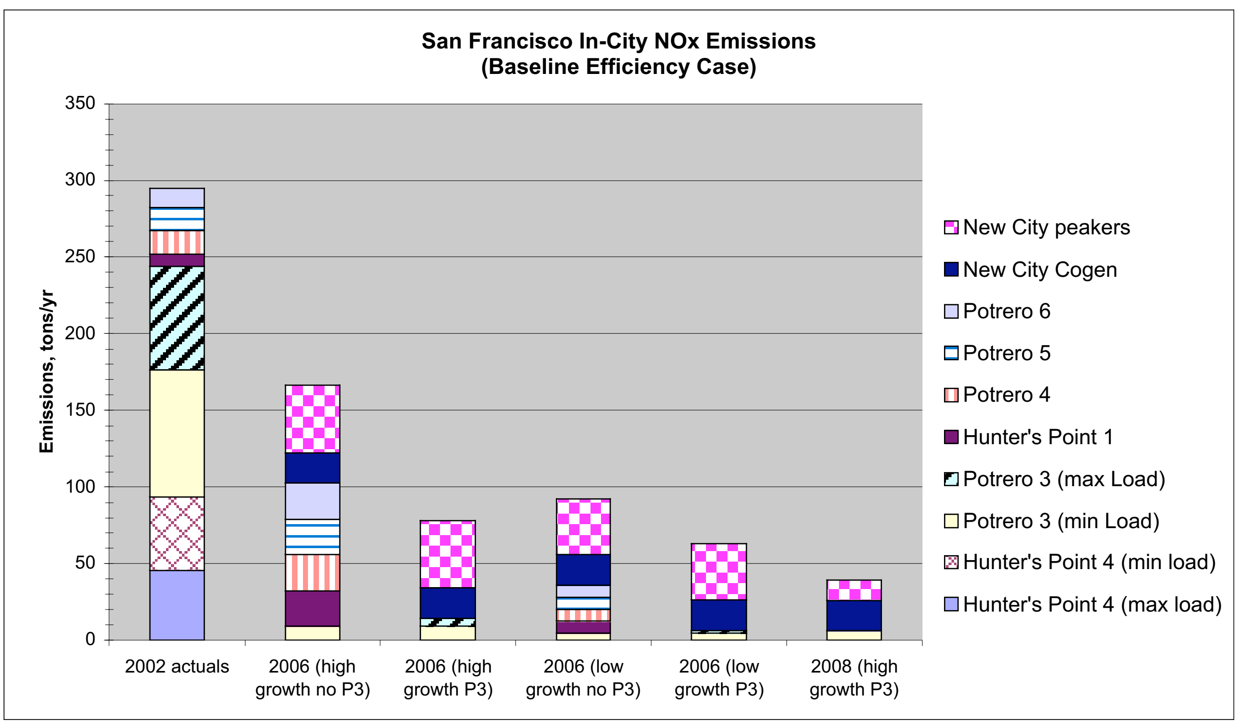
In the later years of the scenarios, distributed cogeneration also reduces emissions, because some of the emissions attributed to the thermal energy supply, and the remaining emissions from electric generation are modest. With the exception of biomass, which has moderate NOx emissions, the renewable resources have no NOx or CO_2 emissions.

Table 41. Emission intensities for new and existing generation sources

	NOx (lb/MWh)	PM10 (lb/MWh)	CO_2 (ton/MWh)
Potrero unit 3 (full load)	0.8	0.08	0.6
Potrero unit 3 (min load)	0.4	0.08	0.7
HP unit 4 (full load)	0.58	0.08	0.6
HP unit 4 (min load)	0.33	0.09	0.7
HP unit 1 peaker	3	0.14	0.9
Potrero 4,5,6 peakers	3	0.14	0.9
New in-City cogen	0.10	0.04	0.4
New in-City peakers	0.19	0.06	0.6
Purchased imports	0.3	0.04	0.4

Using the emissions factors from Table 41 and the projected energy production for the thermal plants, total future emissions can be calculated. Figure 55 and Figure 56 show the reductions in emissions resulting from the replacement of most of the production from the existing generation plants by the planned new City-owned generation capacity. The difference between the two graphs is that in Figure 55, demand follows the baseline projection with no impact of efficiency programs assumed, while Figure 56 shows our high growth, high efficiency scenario. Potrero unit 3 is assumed to be retrofitted in each case.

Figure 55. NOx emissions from in-City generation, baseline efficiency*



*"P3" – Potrero 3 is retrofitted. "No P3" – Potrero 3 is not retrofitted with NOx emissions control and therefore can not run at full load (207 MW), only minimum load (52 MW)

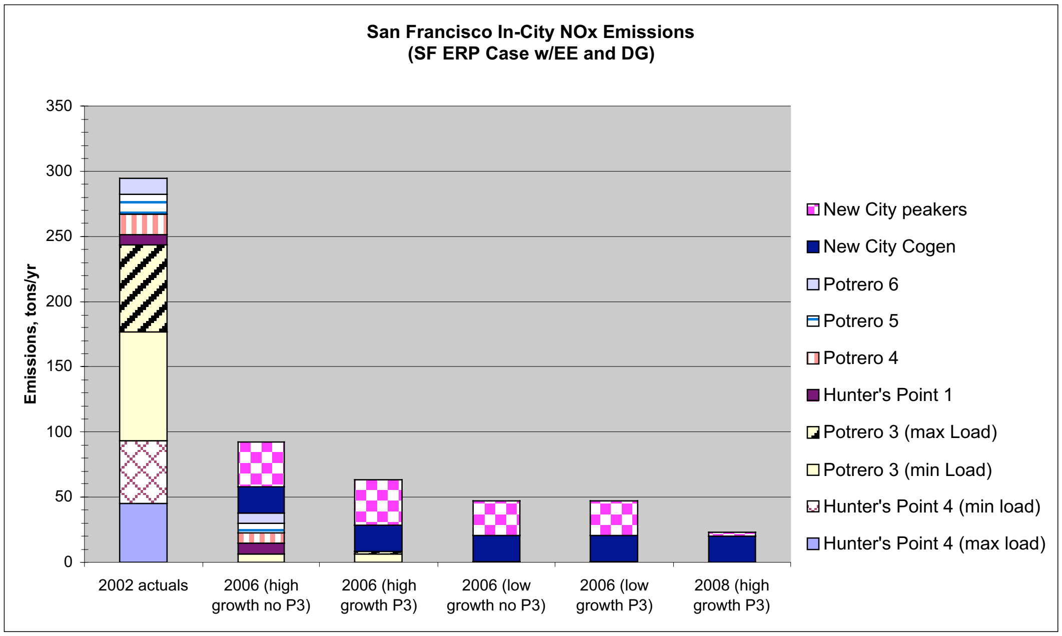


Figure 56. NOx emissions from in-City generation, includes efficiency and DG resources

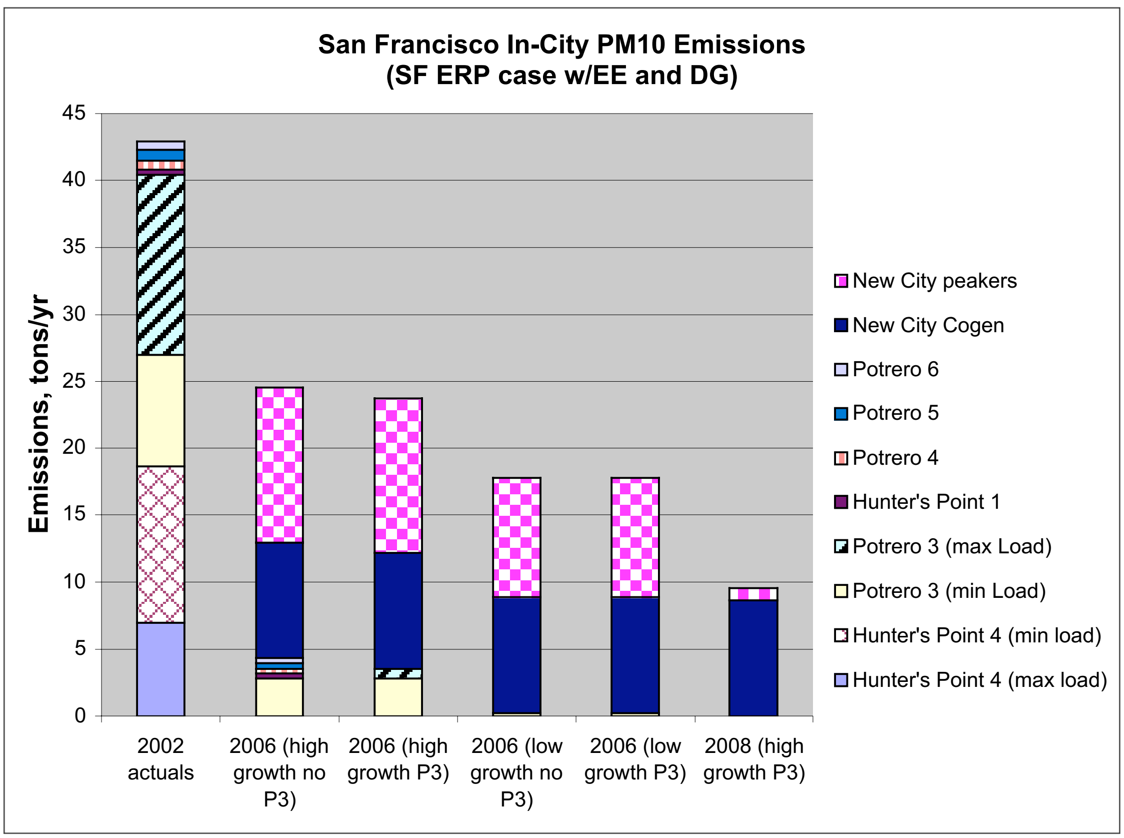


Figure 57. PM10 emissions from in-City generation, includes efficiency and DG resources

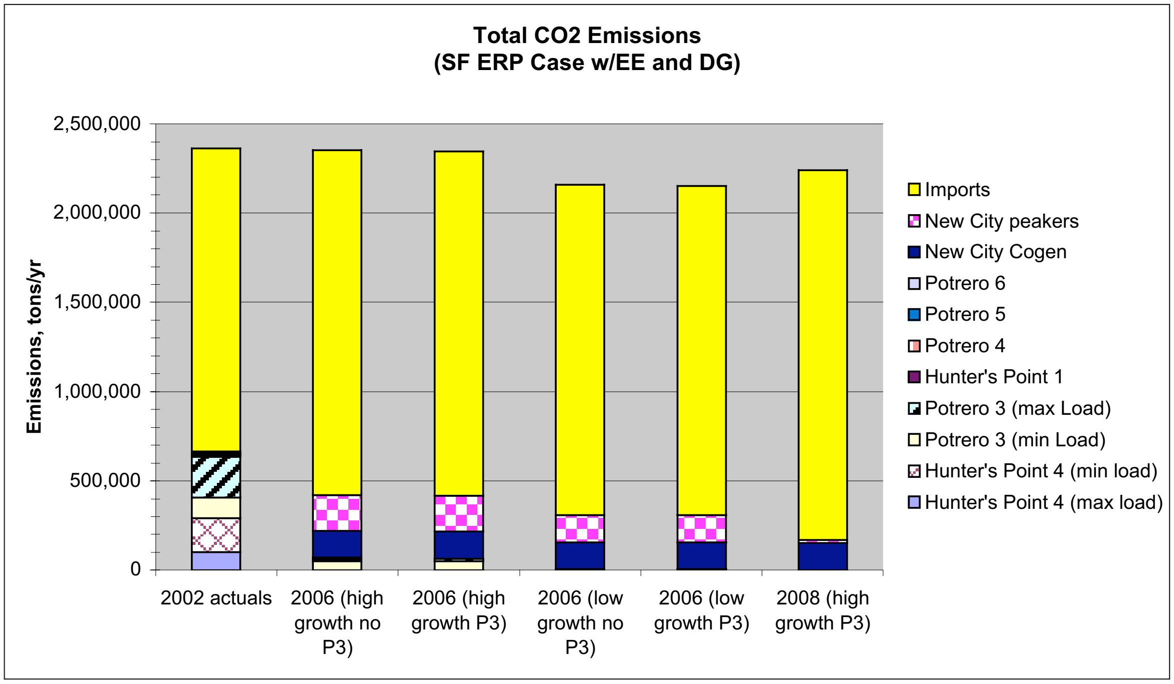


Figure 58. Total CO_2 emissions from in-City generation and imports

Figure 56 through Figure 58 show the effect on emissions of NOx, PM10, and CO_2 in the City in 2006, after the four new combustion turbines have been put in service. As observed earlier with regard to energy production, the operation, and therefore the emissions, of all thermal units can be reduced further when the Jefferson-Martin 230-kV transmission project is complete. This additional import capacity is incorporated into the 2008 case in each of the figures, and it allows more of the City's load to be served by imported power rather than in-City generation.

The emissions results shown above were produced by a dispatch and emissions model developed by RMI in collaboration with the SFPUC. The model projects service hours, energy production and resulting emissions for San Francisco's power plants in the future. This model assumes that Hunters Point Unit 4 is permanently closed in 2005 and that the future Jefferson-Martin 230-kV transmission project is completed between 2006 and 2008, which is the main difference between the results shown above for these two future years. The model also assumes that other needed improvements to the local and regional transmission system, specified by the CAISO as a condition of shutting down Hunters Point, have been finished.

The results show that, although the City continues to rely on fossil fuel-fired generation for a significant share of its future energy, as well as an essential contribution to supply reliability, NOx emissions can be reduced by more than 80% in 2006 and by almost 70% in 2008 and beyond. When in-City energy efficiency reductions and distributed generation resources are considered, emissions can further be reduced by 25% up to 100%. This is because in some scenarios with aggressive efficiency and/or DG, the need to dispatch certain plants on the margin (existing peakers in 2006 and Potrero 3 in 2008) is completely removed, while the run hours or total annual energy generation is also reduced. Particulates and GHGs are also reduced significantly through this strategy. In the longer term (2015 and beyond), the remaining combustion turbines could eventually be replaced with distributed generation, but this would provide an emissions benefit only if fuel cells become cost-effective.

Effect of external costs of emissions on ranking of resource options

Although emissions of local pollutants and GHGs are likely to decrease in San Francisco, the remaining emissions still constitute a future risk. NOx emission regulations might get more stringent, imposing a cost on residual emissions. Also, it is likely that CO_2 and other GHGs will face mandatory regulation, emission charges, or mandatory allowance purchases. Of course, energy efficiency and renewable energy sources produce no emissions and can provide a hedge against future emission risks.

To evaluate the risk that could be imposed by future emission regulations, we recalculated the levelized marginal cost of energy for each of the supply sources that produce significant NOx and/or CO_2 emissions. We selected two levels of emission externality values, or “adders.” The lower level is taken from the CEC Electricity Report of 1994 (ER94), which the last proceeding or decision on the topic of valuing environmental externalities and adders. This document gives externality values of about $9,000/ton ($4.5/lb) for NOx and $9/ton for CO_2. The higher level of externality values is based on high (but far from maximum) estimates of the potential range marginal costs of emission abatement, which we project to be about $25,000/ton ($12.5/lb) for NOx and $25/ton for CO_2. The former value has recently been exceeded during times of high power demand in some of the local California markets for NOx trading credits.

CO_2 values are more difficult to estimate. However, a comprehensive study of reduction options by the DOE national laboratories concluded that U.S. emissions of CO_2 could be returned to the 1990 level by the year 2010 with a carbon emission tax or permit market price of $12.5/ton.[60] If one extrapolates from these findings in combination with the sector-specific results of this study, one finds that the carbon emission tax or permit market price would need to be about $15-25/ton to achieve compliance with the Kyoto Protocol. Thus, we use $25/ton as the high value for CO_2.

Table 42 shows the resulting levelized marginal cost of energy for each of the supply sources, including the impact of the low and high emission externality adders. As expected, the total marginal costs of all the fossil fuel-fired sources increase significantly. However, the relative rankings, however, do not change much at all. This is because the only resource options with no emissions cost adder, renewable sources, are either already very competitive (utility scale wind) or far more expensive than most conventional options (solar PV).

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[60] Interlaboratory Working Group, 1998. *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy-Efficient and Low-Carbon Technologies by 2010 and Beyond*, ORNL-444 and LBNL-40533, Oak Ridge National Laboratory (ORNL) and Lawrence Berkeley National Laboratory (LBNL).

Table 42. Costs of Generation Technologies in San Francisco with External Emission Costs

Generation Option	Marginal Cost of Energy - No Adder ($/kWh)	Marginal Cost of Energy - Low Adder ($/kWh)	Marginal Cost of Energy - High Adder ($/kWh)
Hetch Hechy hydro upgrade	$0.045	$0.045	$0.045
Utility scale wind	$0.047	$0.047	$0.047
Imports 1	$0.054	$0.059	$0.068
SF Williams' Cogeneration	$0.060	$0.063	$0.071
Cogeneration	$0.068	$0.072	$0.079
Imports 2	$0.074	$0.079	$0.088
DG - small gas ICEs w/CHP	$0.086	$0.099	$0.122
Biomass (direct combustion)	$0.089	$0.090	$0.092
Hunters Point & Potrero peakers	$0.090	$0.112	$0.151
Potrero (retrofit minimum)	$0.091	$0.097	$0.108
SF peakers	$0.094	$0.099	$0.108
DG - micro-turbines w/CHP	$0.099	$0.104	$0.113
Potrero (retrofit maximum)	$0.101	$0.107	$0.117
DG – high temperature fuel cells w/CHP	$0.104	$0.107	$0.112
Simple Cycle Gas	$0.111	$0.116	$0.125
DG – low temperature fuel cells w/CHP	$0.134	$0.136	$0.141
Small scale wind	$0.155	$0.155	$0.155
Solar PV	$0.257	$0.257	$0.257

The environmental externality cost adders have a more significant impact on the rankings of supply resource options in comparison to energy efficiency measures, which also have no emissions cost adder. The recalculated marginal costs are included in the integrated resource supply curve shown in Figure 59. The higher marginal costs of supply options result in a greater cost advantage for energy efficiency measures. These results suggest that, if emission benefits are considered, energy efficiency will be cost-effective up to a higher marginal cost threshold, justifying more expensive measures and larger savings through DSM programs.

Longer-term emission scenarios

Dramatic emission reductions are achieved in all the ERIS scenarios, mostly due to the retirement of the Hunters Point power plant and the retrofit and eventual retirement of Potrero unit 3. Although the new in-City peakers release both local emissions and GHGs, the installation of these turbines will help to reduce emissions, because they will replace the Hunters Point plant and reduce the number of hours that the existing oil-fired peakers need to run. As a result, all the scenarios result in persistent emission reductions over time.

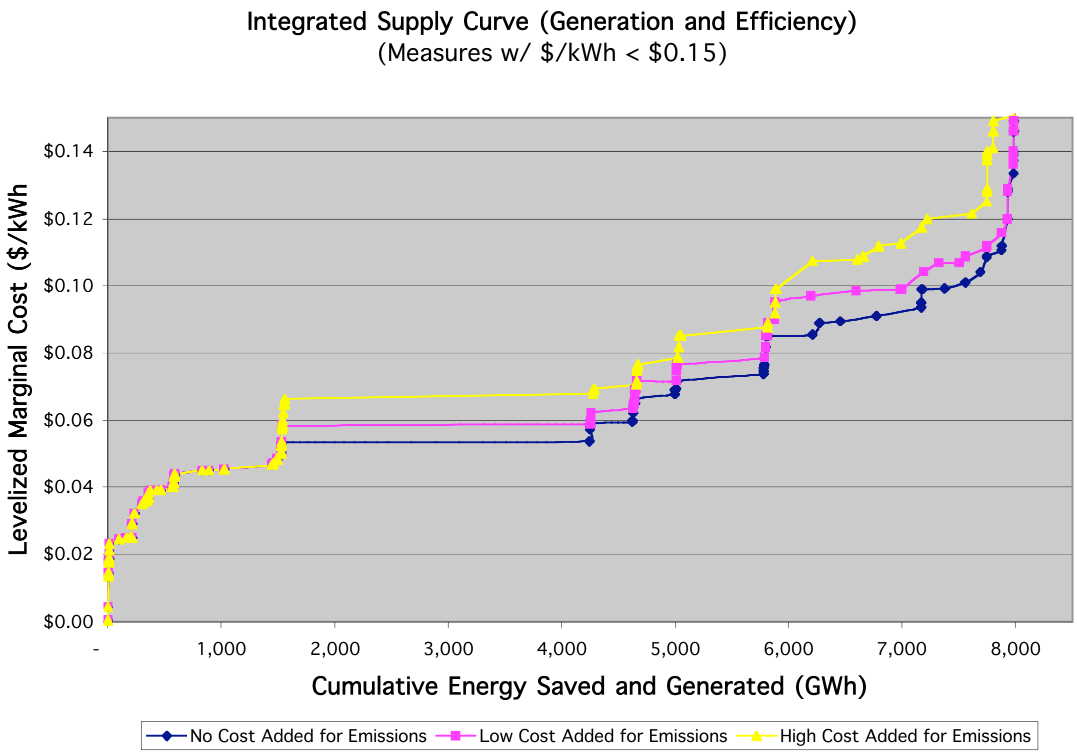

Figure 59. Integrated resource supply curves for San Francisco with emissions adders

The total CO_2 and NOx emissions from generation sources serving San Francisco are shown in Figure 60 and Figure 61. These emissions include those caused by power that is imported to the City from fossil fuel-fired generation outside the Peninsula, as well as the remaining in-City generation and DG sources.

CO_2 emissions drop about 20% in the first five years of all the scenarios, due to the retirement of the old, inefficient generation plants. Subsequent reductions depend mostly of the energy demand (net of efficiency savings). Emissions in the high-load, moderate-efficiency scenarios remain fairly constant, while emissions in the low-load, high-efficiency scenarios fall to almost 50% below present levels by 2020. In addition to the emission reductions due to reduced demand, renewable energy from wind power makes a significant contribution to reducing CO_2 emissions in the scenarios.

Total NOx emissions drop about 40% in the first five years of all the scenarios, again due to the retirement of the old generators. Subsequent reductions follow a similar pattern as CO_2 emissions. Emissions in the high-load, moderate-efficiency, low-DG scenarios remain fairly constant, while emissions in the low-load, high-efficiency, high-DG scenarios fall to about 80% below present levels by 2020. In addition to the emission savings due to demand reductions, further NOx emission reductions result from the growth of fuel cell DG in the high-DG scenarios. Although fuel cells cause some CO_2 emissions, their NOx emissions are negligible.

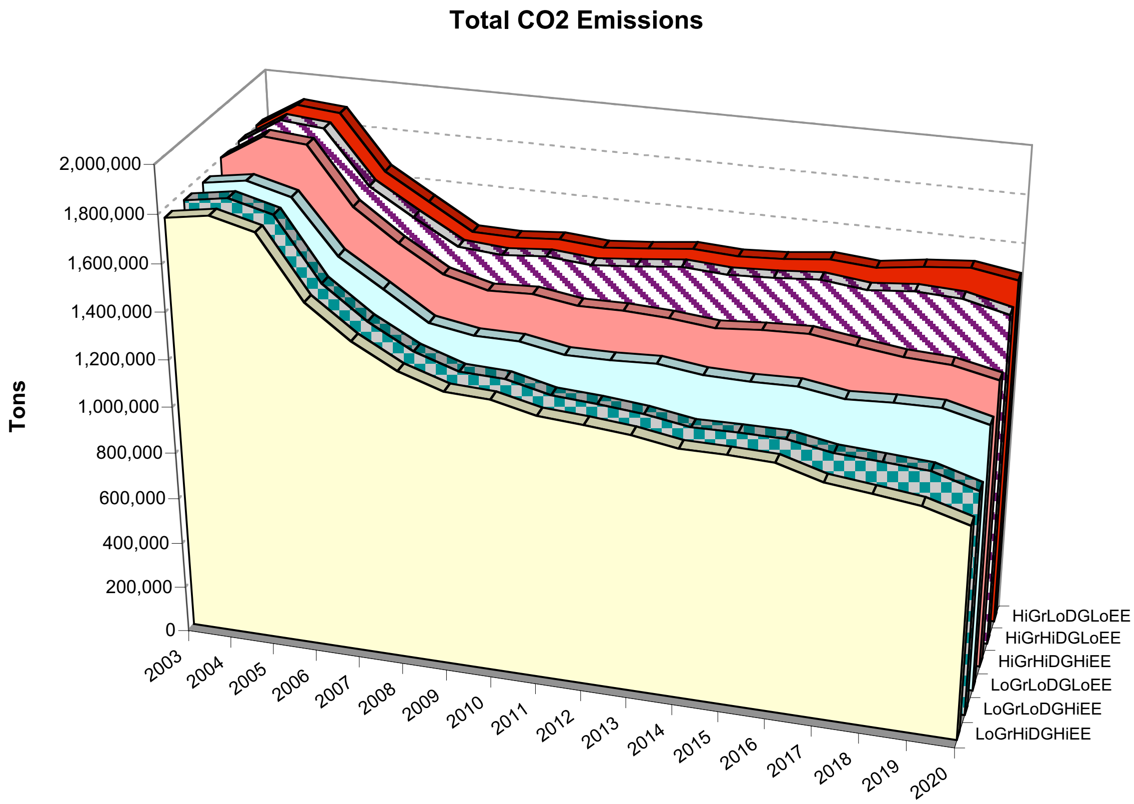

Figure 60. CO_2 emissions caused by generation serving San Francisco, 2003-2020

Residents of San Francisco are also concerned about local emissions in the City, as well as the concentration of emissions in low-income neighborhoods near the Hunters Point and Potrero plants. While CO_2 emissions are of only global, rather than local concern, in-City NOx and particulate (PM-10) emissions are a key indicator of local environmental quality. The in-City NOx and PM-10 emissions for each scenario are shown in Figure 62 and Figure 63.

Dramatic reductions of 80-90% in local NOx emissions are achieved in all the scenarios. Most of the reductions occur in the first five years, and these reductions persist throughout the time horizon to 2020. The main cause of the reductions is the retirement of the existing, old power plants. Energy efficiency and renewable sources help keep future emissions low.

Similarly, local PM-10 emissions fall by more than half in the first five years. However, in-City PM-10 emissions increase significantly in the 2008-2015 timeframe to a level that is still 40-50% below present levels, depending mostly on the energy demand (net of efficiency savings). This increase is mostly due to the assumed growth of DG in the City, which is mostly powered by gas-fired engines and microturbines initially. During the last five years of the scenarios, fuel cell DG growth stops the increase in local PM-10 emissions.

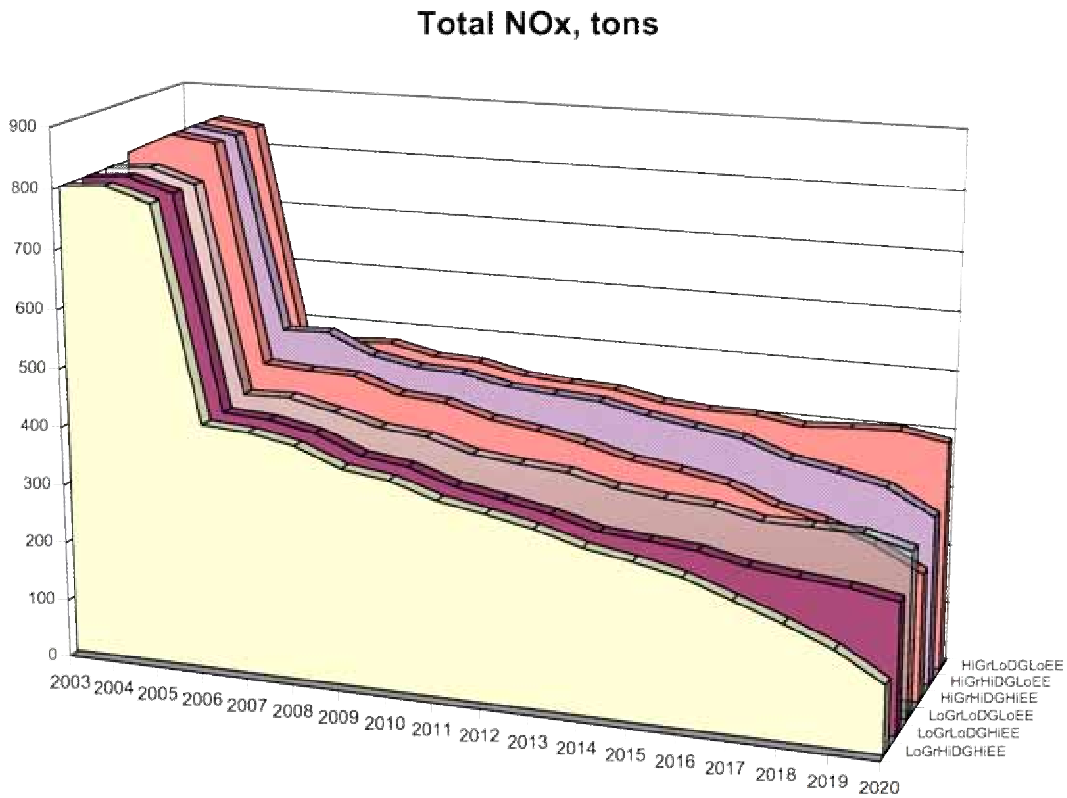

Figure 61. NOx emissions caused by generation serving San Francisco, 2003-2020

Total stationary CO_2 emissions

In addition to the urgent emissions goal of reducing local emissions from power generation at Hunters Point and Potrero, reducing CO_2 emissions and the City's impact on the global climate is also a priority. Our analysis of electric energy supply and demand accounts for the CO_2 emissions caused by San Francisco's electricity use, but it is also important to consider direct natural gas use and its impact on total City CO_2 emissions. We can use the ERIS scenario analysis to estimate CO_2 emissions from all stationary sources serving San Francisco's energy needs, including direct natural gas use, in-City power generation and remote generation of power that is imported to the City.

Despite the growth in demand for energy services in all the ERIS scenarios, and the continued (but gradually diminishing) reliance on natural gas, San Francisco can reduce its CO_2 emissions from stationary sources (all sources except transportation) significantly. Total stationary CO_2 emissions are shown in Figure 64 for two scenarios, one high-load and one low-load (cases 2 and 5). These are both moderate efficiency scenarios, so emissions in the high efficiency scenarios (cases 3, 4, 7 and 8) would be lower still.

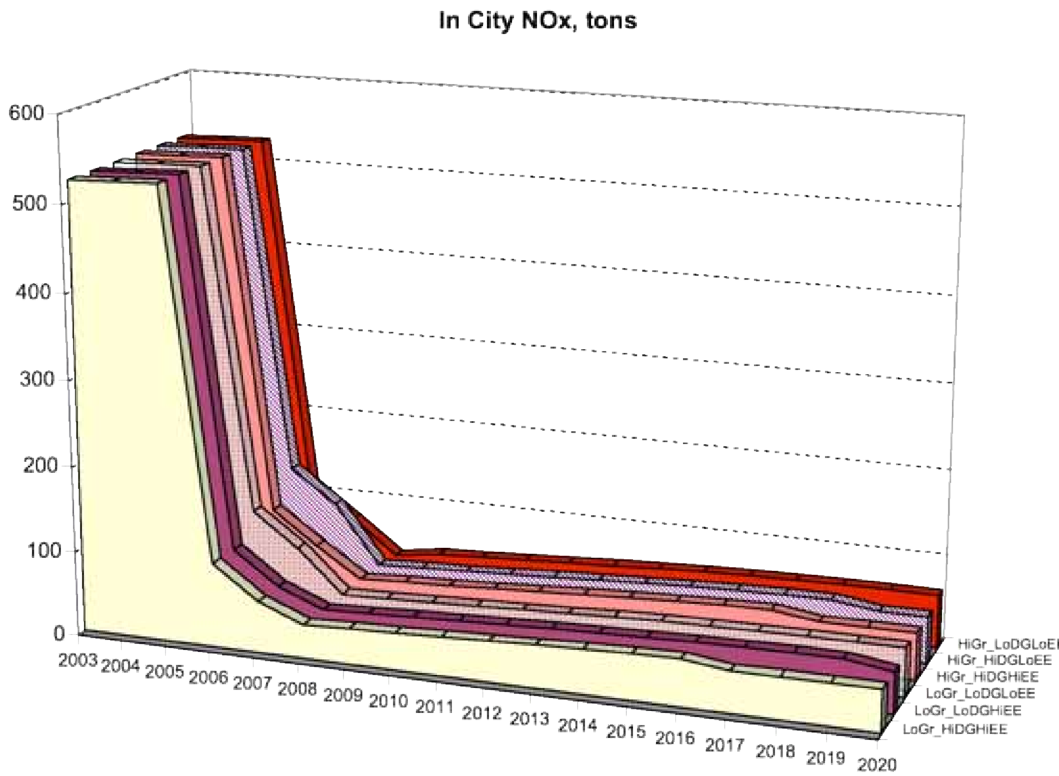

Figure 62. NOx emissions in the City of San Francisco, 2003-2020

To meet the Mayor's goal of 20% CO_2 emission reduction from the 1990 level of 9.1 million tons CO_2 equivalent, San Francisco would have to reduce emissions by about 2 million tons from the 2002 level of 9.3 million tons, according to the SF Department of the Environment (SFE).[61] In order to compare our emission calculations to those of SFE, we have to increase the CO_2 emissions (and savings) from electricity use to account for the higher emission intensity used in the SFE CO_2 emission inventory.[62]

The scenario analysis shows that the cost-effective reduction measures that are included in the ERIS portfolios can make a substantial contribution to meeting the City's goal. Using our emission intensity assumption, total reductions in stationary emissions in 2013 range from 0.4 million tons (11%) in the high growth, moderate efficiency scenarios to 0.8 million tons (22%) in the low growth, high efficiency scenarios. In 2020, emission reductions range from 0.8 million tons (22%) in the high growth, moderate efficiency scenarios to 1.3 million tons (35%) in the low growth, high efficiency scenarios.

[61] SF Dept. of the Environment, 2003, *San Francisco Climate Action Plan*, draft.
[62] SFE used an emission intensity based on the entire western U.S. grid, which is substantially higher than the California average value used here, because of the greater use of coal-fired generation outside California.

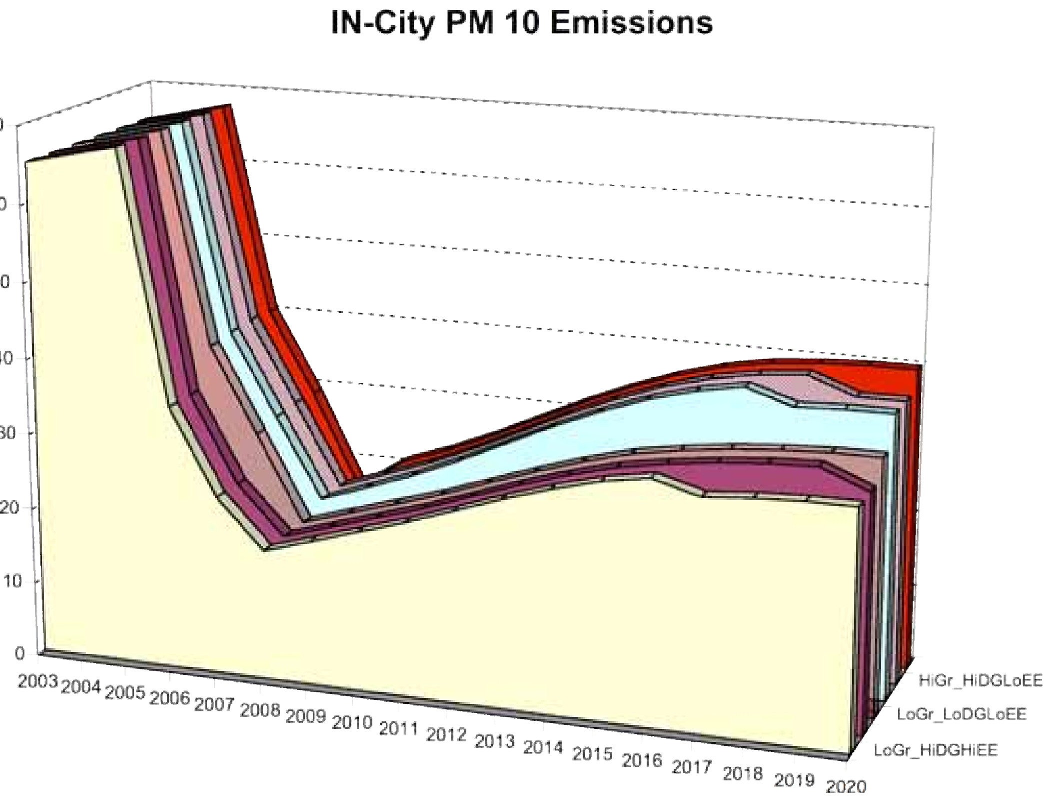

Figure 63. PM-10 emissions in the City of San Francisco, 2003-2020

Applying the emission intensity assumption used by SFE, the CO_2 emission reductions in 2013 range from 0.6 million tons in the high growth, moderate efficiency scenarios to 1.2 million tons in the low growth, high efficiency scenarios, and from 1.0 million tons in the high growth, moderate efficiency scenarios to 1.7 million tons in the low growth, high efficiency scenarios in 2020. The latter case represents 85% of the Mayor's emission reduction target.

Additional CO_2 emission reductions would have to be made in the transportation sector. Given the difficulty of reducing mobile emissions, it appears that it will be difficult to achieve the 20% reduction goal by 2012, even the most aggressive ERIS portfolio is fully implemented and significant reductions are made in transportation. However, the ERIS portfolios can provide a good start for achieving this goal before 2020, assuming that at least 10% reductions can be achieved in transportation.

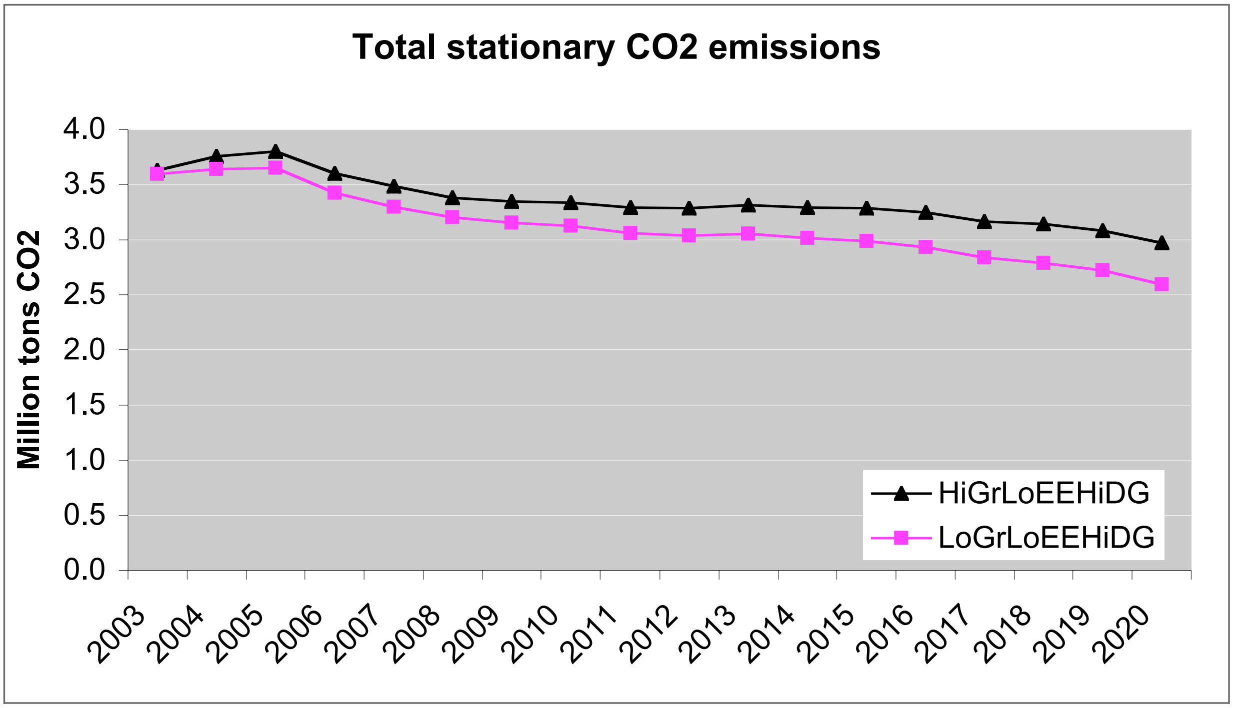

Figure 64. Total CO_2 emissions from stationary sources serving City energy demand

Environmental Equity

Local in-City NOx and PM-10 emissions are also an important indicator of environmental equity, because of the localized health and air quality impacts. Fortunately, it appears that the technologies installed are able to reduce these emissions 80-90% in all scenarios. Moreover, the distribution of emissions is not as concentrated in the neighborhoods near the Hunters Point and Potrero Hill plants. In all scenarios, the most dramatic reductions in local emissions result from retiring the Hunters Point plant and from retiring Potrero unit 3 or upgrading its emissions control equipment. *All scenarios show a dramatic improvement in environmental equity.*

Table 43 and Table 44 show the absolute and relative emission reductions in the Hunters Point and Potrero Hill areas in the high-growth, moderate-efficiency, low-DG scenario with no retrofit of Potrero unit 3, which is the worst-case scenario for local emissions. Absolute NOx and PM-10 emission levels in these areas are reduced by more than 70% in the first few years and by more than 90% in later years. Also, the relative distribution of emissions becomes more equitable, as the share of in-City emissions in these areas falls from more than 80% today to less than 50% in 2006 and less than 15% in later years. Emission levels in all other scenarios are lower still.

Table 43. Reduction in NOx emissions from Hunters Point and Potrero Hill (HP-PH) areas in high-growth, moderate-efficiency, low-DG scenario with no retrofit of Potrero unit 3

	2003	2006	2013	2020
In-City NOx Emissions (tons)	524	148	55	55
HP-PH NOx Emissions (tons)	484	79	8	8
HP-PH Reduction from 2003	-	84%	98%	98%
Ratio HP-PH/In-City Emissions	92%	53%	15%	15%

Table 44. Reduction in PM-10 emissions from Hunters Point and Potrero Hill areas in high-growth, moderate-efficiency, low-DG scenario with no retrofit of Potrero unit 3

	2003	2006	2013	2020
In-City PM-10 Emissions (tons)	65	40	31	37
HP-PM-10 Emissions (tons)	53	16	3	3
HP-PH Reduction from 2003	-	70%	94%	94%
Ratio HP-PH/In-City Emissions	82%	40%	10%	8%

Local Economic Development

In considering its energy future, the City of San Francisco seeks to secure a solid economic foundation for residents and businesses. The City would like to keep dollars in the local economy and discourage actions that send more dollars to external vendors. To evaluate these potential flows, we consider each of the resources employed in the ERIS scenarios and evaluate their potential for keeping dollars in the local economy and creating local jobs.

First, we discuss each of the resources and the extent to which they are able to keep dollars local, both in the initial capital costs and in the annual operating costs once capacity is installed. Next, we determine which of the resources selected in the ERIS scenarios are significantly different, in terms of their local economic content, from a status quo, central energy plan. Finally, we evaluate one of the ERIS scenarios to estimate its potential impact on local employment.

The technologies range considerably in their degree of market maturity. For some technologies, a great deal of intellectual property is built into the equipment and the manufacturing capacity is largely external to the local economy. Combustion turbines, microturbines, fuel cells, and wind turbines are all in this category. Capital costs are high, while the cost of the labor to install the equipment is a smaller percentage of the total capital costs.

Other technologies such as energy efficient equipment are typically incrementally more expensive than the equipment being replaced. Therefore, a greater percentage of the costs is associated with local labor. Unlike generation technologies, which often require employees of the original equipment manufacturer to handle most business transactions and technical service, licensed local equipment vendors and contractors can generally conduct the majority of sales, installation and servicing of energy efficient equipment. Similarly, peak load management systems are available locally and their deployment requires local labor (see Table 45).

Table 45. Degree to Which Capital Costs of the Technologies Remain Local

Technology	Mostly Local	More Local than External	Evenly Distributed	More External than Local	Mostly External
Potrero Retrofit				X	
New City Generation					X
Distributed Generation					X
Solar			X		
Biomass				X	
Efficiency / DSM		X			
Wind (Alameda)				X	
Hetch Hetchy Hydro					X
Transmission			X		

Annual operating cost is another factor that determines whether technology costs stay local or leave the local economy. The best technologies in this regard are those requiring little or no fuel. Solar power, energy efficiency, and transmission expansion have low operating costs, which are split between equipment replacement and labor costs. Both Hetch Hetchy hydro and wind farms have no fuel costs, and plant owners are local. On the other hand, most of the equipment and a large fraction of the labor are external to the local economy.

The fossil fuel-based technologies, including combustion turbines and distributed generation (cogeneration, microturbines, fuel cells), require large annual costs for fuel purchases. Because fuel costs largely exit the local economy and the remaining annual costs for plant operations and maintenance are split between local labor and external equipment sales, these technologies keep a relatively small fraction of their total costs in the local economy. The most extreme case of exporting funds is by purchasing power to import. Only a small fraction of the costs go to the local expenses of other power plants in the Bay Area. Most of the dollars go to external equipment manufacturers and the parent companies of the power plants. On the other hand, much of the cost of the transmission capacity that carries imported power is local (see Table 46).

Table 46. Degree to Which Annual Operating Costs of the Technologies Remain Local

Technology	Mostly Local	More Local than External	Evenly Distributed	More External than Local	Mostly External
Potrero Retrofit					X
New City Generation					X
Distributed Generation				X	
Solar		X			
Efficiency / DSM		X			
Wind (Alameda)			X		
Hetch Hetchy Hydro			X		
Transmission	X				
Imported Power					X

The ability of an energy resource portfolio to keep dollars in the local economy depends on the technologies employed in that portfolio. The ERIS portfolios rely on a broad array of new City-owned generation (fossil fuel, wind, solar and improved hydro) and distributed generation (gas turbines, wind and improved hydro) and distributed generation (engines, microturbines, fuel cells, solar and cogeneration) to meet San Francisco's electricity supply needs. For all of these technologies, capital costs flow mostly out of the local economy, and annual operating costs consist mostly of fuel costs that similarly flow outward. Although distributed resources have economic and environmental advantages, and some appear to have significant local content, it is not certain that they recycle more dollars or create more jobs than central power generation and transmission. The available methods for estimating local employment impacts are not precise enough to detect a significant difference between centralized and distributed resources on the supply side.

On the demand side, however, energy efficiency measures can help keep both the capital and annual operating costs recycling through the local economy. In this case, there appears to be a clear difference between the ERIS portfolio and a more centralized, supply-focused energy plan, and we can quantify this difference in terms of employment impacts.

To evaluate the employment effects in the ERIS scenarios, we use a methodology similar to that used by the American Council for an Energy Efficient Economy[63], which we adapted in a simplified form to San Francisco with updated assumptions from a November 2002 analysis of impacts of energy efficiency programs in the southwestern U.S.[64] When energy efficiency investments cause reduced demand for energy purchases, the impacts on employment occur in the following four ways:

1. Local *trade jobs are created directly* for the production, sale, and installation of efficiency measures.
2. The *increased purchasing power* of customers whose energy bills are reduced creates jobs through their increased consumption of other good and services.
3. Conversely, the capital expenditures on efficiency measures cause job reductions indirectly through *decreased purchasing power* for other goods and services.
4. Efficiency savings cause job *reductions in energy supply* industries (electricity and gas).

The net effect of these influences on employment are summarized in Table 47 for the high-growth, moderate efficiency scenarios (cases and 1 and 2). This simple analysis of the job impacts of energy efficiency programs suggests that efficiency investments would lead to the net creation of about 250 jobs per year, or about 4,000 by 2020. These quantities are somewhat less in the low-growth scenarios, moderate efficiency scenarios (cases and 5 and 6) and higher for the aggressive efficiency scenarios (cases 3, 4, 7 and 8), up to 400 jobs per year and 6500 by 2020.

Table 47. Estimated job impacts of moderate efficiency programs in high-load scenarios

[63] Geller, H., J. DeCicco, S. Laitner. 1992. Energy Efficiency and Job Creation: The Employment and Income Benefits from Investing in Energy Conserving Technologies. Washington, D.C.: Amercian Council for an Energy Efficient Economy.

[64] Southwest Energy Efficiency Project. 2002. The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest. (A report in the Hewlett Foundation Energy Series).

Type of employment impact	2006	2013	2020
EE trade jobs created	+400	+600	+800
Job gains from purchasing power added by EE savings	+500	+2200	+4600
Jobs lost via less purchasing power from EE expenditures	-300	-500	-700
Energy supply jobs lost	-100	-400	-700
Net jobs gained	+500	+1900	+4000

The jobs created as a result of energy efficiency investments tend to be located in the region where the efficiency investments occur. Thus, we expect that there would be a significant benefit to San Francisco employment. Note that some of the jobs gained in efficiency work and lost in energy supply could both occur within an energy utility such as PG&E. Thus, it is possible that such a utility might not experience much net change in employment, but rather a shift in the type of jobs. This type of shift could involve reassigning existing employees or replacing existing staff with new employees.

Note that the direct employment impacts of efficiency investments are small compared to the accumulating impact of the purchasing power created by customer energy savings. The direct impacts are mostly offset by indirect job reductions from the purchasing power lost due to the efficiency expenditures. Jobs are also lost directly in the energy supply sector, but this effect appears much less significant than the indirect gains from the efficiency savings.

PROJECT-LEVEL ANALYSIS

In order for San Francisco to realize the benefits of energy efficiency (EE) and distributed generation (DG) projects, the specific barriers restraining their implementation must be identified, addressed and acted upon when possible. High-level, conceptual thinking (top-down) is less useful to identify the barriers in a constructive way, as the barriers often exist in the details of financial transactions and inter- or intra-organizational dynamics. More effective are detailed, close-up analyses of how programs would affect the entities involved, and what the main drivers of these effects are. For this purpose, seven specific models of hypothetical EE and DG projects in San Francisco were developed and analyzed.

The models are designed to estimate the financial effects of the projects on the entities involved. They provide a quantitative basis for examining if existing regulations, prices, technological factors, incentives and other variables are causing barriers. A separate financial analysis was developed from the perspective of each entity directly involved. This was necessary not only because different barriers may exist from different perspectives, but also because doing so allowed barriers arising from the relationships or interactions between these entities to be identified and addressed.

The models are built upon hourly data for a full year. This permits a depth of analysis that was necessary in order to ensure that the models reflect the changing value of power at different times of the day and year. Namely, in most cases measures that save or generate energy during times of highest consumption (normally weekday, daytime hours) displace energy that was previously purchased at high prices, thereby increasing the value of these measures.

It should be noted that the degree to which the financial results of actual implementation of projects similar to those modeled can be expected to match the models' financial results is limited. The limitations arise both from the information available for use as inputs to the models, as well as the resulting assumptions made. For this reason, despite the models' quantitative nature, it is not intended that the values they yield be taken as predictive. Rather, the usefulness of these models lies in the relative magnitudes of the results, in the relationships that they reveal between the entities involved, and in the sensitivities of the results to changes in the inputs.

The projects modeled were chosen so as to represent a wide range of the potential that exists in San Francisco for energy efficiency and distributed generation. They include projects in the residential, commercial and municipal sectors, as well as two types of distributed generation technologies. The projects are:

- Energy Efficiency and Distributed Generation in a New Residential Construction Project
- Energy Efficiency in a Municipal General Account Customer Building
- Energy Efficiency in a Municipal Enterprise Account Customer Building
- Distributed Generation in a Municipal Enterprise Account Customer Building
- Energy Efficiency in a Commercial Building
- Distributed Generation in a Commercial Building
- Combined Energy Efficiency and Distributed Generation in a Commercial Building

The model of each project, when used with inputs consistent with the current environment (such as electric rates, capital costs and interest rates), allows the analysis of each variable to discover which ones are causing the primary barriers. They also allow the discovery of what potential solutions to the barriers could exist if policy were to be implemented to change these variables.

The models also allow the consideration of future scenarios, through the analysis of how variables may change, or what new variables may become relevant over time. Variables such as high capital cost, which are dependent upon time and technological advancement, are largely out of the control of the City of San Francisco. However, changes to these variables will occur with time, and these models permit the development of contingency plans to respond to such future changes. Lastly, they provide information for policy makers on some of the potential long-term effects that could be expected from changes in policy made today.

Summary

Each model is intended to identify the main barriers and incentives to the implementation of energy efficiency (EE) or distributed generation (DG) projects, from the perspective of each party to the investment. For each project, we examine one or more cases involving different financial arrangements between the end user(s) of the energy, the financial investor and other affected parties. Table 48 summarizes our observations regarding the most appropriate party to serve as financial investor for each type of energy investment evaluated.

Table 48. Summary of Most Appropriate Financing Sources for EE and DG Projects

Project Name	Who Should Finance	Explanation
1) EE in Commercial Building	ESCo	Short payback, high NPV are possible
2) DG in Commercial Building	ESCo	Short payback, high NPV are possible, experienced ESCo necessary for success
3) DG and EE in Commercial Building	ESCo	Same as above, possible synergies between DG and EE systems if design is integrated and installation is turnkey
4) EE and DG in New Residential Construction	Homeowner	Opportunities exist for inexpensive mortgage financing and State incentives for PV. Ammortized energy cost savings can be shared between builder and home buyer
5) EE in Municipal General Account Customer	SFPUC	Saved energy can be sold at a higher rate to other customers
6) EE in Municipal Enterprise Account Customer	SFPUC	Through a shared-savings contract between SFPUC and Enterprise Account customer, considerable value can be captured for both parties
7) DG in Municipal Enterprise Account Customer	ESCo	Multiple tax-based incentives and State rebates result in rapid payback

Table 49. Summary of Barriers to Financing EE and DG Projects

Project Name	Principle Barriers	Policy Recommendations for SFPUC and / or City of San Francisco
1) EE in Commercial Building	Relatively high existing penetration rate of EE lighting limits potential for cost-effective saved energy. Also, low building occupancy could result in losses to investor.	Create incentives or implement mandates to increase both demand for and supply of energy efficient commercial buildings.
2) DG in Commercial Building	Business model is sensitive to current energy costs and interconnection regulations	Create utility incentives to encourage the cleanest, most efficient DG systems, so as to realize reliability and grid benefits
3) DG and EE in Commercial Building	Same as above	Same as above
4) EE and DG in New Residential Construction	No realization of the value of low energy bills in home sales price, which would encourage builders to build efficient homes and homebuyers to buy them	Educate real estate professionals, potential homebuyers and builders about potential financial benefits of buying or building an energy efficient home or a home with a PV system
5) EE in Municipal General Account Customer	Overcoming internal organizational barriers to achieving City-wide benefit	Shift incentive structures of City employees to encourage the maximization of the City's bottom line, as opposed to one department or one building's.
6) EE in Municipal Enterprise Account Customer	1) Large loss to SFPUC when ESCo invests 2) Loss of high-value energy sales	1) SFPUC should invest, or pursue community aggregation to offset loss. 2) Develop a contracting strategy with measurement and verification to allow shared savings contracts with building's tenants. Substantial returns are possible for both parties with this model.
7) DG in Municipal Enterprise Account Customer	Net loss to SFPUC when ESCo invests	Pursue community aggregation, change structure of power market to provide payments for added peak capacity resulting from PV system

Even if the main investor benefits, however, if one or more of the other parties does not benefit or actually loses money, the project's success could still be jeopardized. In projects where this is the case, we consider more than one financial arrangement and evaluate and compare the implications for the investor and other stakeholders. Table 49 summarizes our observations regarding the potential barriers to financing each type of energy investment considered. In addition, potential policy measures are suggested to help overcome some of these barriers.

The recommendations shown in Table 48, as well as the barriers and policy options identified in Table 49 are discussed in more detail below in relation to each energy investment case. To summarize, the results indicate that:

- *New residential construction* presents a good opportunity for inexpensive mortgage financing. Ammortized energy cost savings can be shared between the builder and the buyer, as long as some of the value of energy efficiency can be captured in the sales price. If so, the builder can realize additional profit while the net of the buyer's total monthly mortgage and energy bill payments is reduced. Similar results apply to new commercial construction, but buyers' incentives are less clear if they do not occupy the building and instead pass all energy costs on to the tenants.
- *Commercial energy efficiency* can be highly cost-effective, but there are often split incentives between building owners and tenants. Energy service companies (ESCos) provide a vehicle for financing and implementation; however, government or utility incentives may be needed to increase the amount of efficiency measures that are cost-effective under expensive private financing.
- The financial success of *energy efficiency in municipal facilities* depends on whether the facility is a General Account customer with low power rates or an Enterprise Account customer with high power rates. While General Account customers themselves have little incentive to save cheap energy, the City (through SFPUC) can profit from implementing efficiency projects on behalf of these customers, as the saved energy is worth more if sold elsewhere. If the SFPUC implements efficiency projects for Enterprise Account customers, significant revenue is lost unless the customers' savings can be shared contractually to create a win-win deal.
- Due to high retail rates, *distributed generation in the commercial and municipal* (Enterprise Account) sectors can be profitable for third-party investors, if they can secure utility interconnection agreements and take advantage of multiple tax-based incentives and State rebates. For DG, municipal facilities might also be able to employ low-cost municipal bond financing, such as that provided by Proposition H.

Assumptions

Assumptions common to all energy efficiency projects

All energy efficiency projects modeled are interior lighting retrofits. Interior lighting was chosen as the end use to target due to availability of data and the fact that it is by far the largest source of economically achievable energy savings potential in San Francisco commercial buildings (45% of the total).

All energy efficiency measures were assumed to have a lifetime of 15 years. It was assumed that measures with lifetimes shorter than this were installed in order to realize 15 years of savings, and the costs were adjusted accordingly. The cash flows evaluated for each project include all those over the expected lifetime of the EE measures.

Assumptions common to all municipal building projects

As described earlier, the City has contracts with the Modesto and Turlock Irrigation Districts that will change at the end of 2007. As the investor, the financial effect on the City of implementing an EE or DG project will be different after this date. The models of these projects attempt to capture the effect of these changes by tracking the amounts and prices at which marginal power would be sold to the Districts as opposed to the spot market or other Municipal end users.

All of the models described in this chapter assume average availability for power from Hetch Hetchy, (i.e. the median of recent historical rainfall) as specified by the City. The sensitivity of the SFPUC's return to this assumption is shown in the description of the *Energy Efficiency in a Municipal General Account Customer Building* model.

For all projects involving a Municipal building, certain data on average commercial buildings in San Francisco were used. Municipal buildings in general have use patterns that resemble commercial buildings as opposed to residences or industrial facilities.

Assumptions involving projects' financial effects on PG&E

The general effects of EE and DG projects on PG&E are both lower costs and lower revenues. In projects involving PG&E electric customers, lower costs to the utility result from avoiding both the cost of purchasing the amount of energy that is saved or generated from the spot market[65] as well as the cost of transmitting this energy to the building in question. Lower revenues to PG&E result from the loss of energy sales to the end user who is implementing EE or DG. This lower revenue is comprised of their markup both on the cost of energy as well as on the cost of transmitting and distributing the power.

Calculations of capital cost

The capital costs of the projects are based on a variety of sources, as described in each individual project description. The energy efficiency projects in Commercial and Municipal buildings are based on the same data, derived from the report "California's Secret Energy Surplus, the Potential for Energy Efficiency," by Xenergy Inc. (henceforth 'the Xenergy report').

This document provided cost and potential energy savings data for lighting energy efficiency measures in existing commercial buildings in California. A weighted average capital cost was derived from these data in the form of a cost per kWh of potential savings. This in turn was multiplied by the project's estimated energy savings, yielding a total capital cost. An administrative cost per kWh saved was then added to this, resulting in the total installed cost.

[65] While PG&E does receive much of the power that it resells to end users through long-term contracts with independent power producers, it was assumed for the sake of these models that on the margin, spot market purchases are made to cover variations in load. It is then the price of this marginal energy that is avoided by PG&E when an EE or DG project is implemented.

Assumptions regarding energy service companies (ESCos)

The option of enlisting an ESCo to design, install and manage energy efficiency or distributed generation projects is one that the City must consider carefully. A summary of the advantages and disadvantages of such a choice follows.

Advantages:
- The ESCo shares part of the risk of the project, and in most cases all of the financial risk.
- As subject matter experts, ESCos are often more adept at the issues and tasks involved in these projects. This can result in increased electric savings, lower project costs, and faster implementation, as well as more effectively verified savings..

Disadvantages:
- The lack of transparency could make it difficult for the City to track the costs and revenues that the ESCo is realizing.
- A loss of control over the facility and its operation can result, as the ESCo may not be as responsive to problems involving new equipment as an on-site facility manager would be.
- ESCos usually require a higher return on investment than does a public entity or their creditors, potentially limiting the number of projects that can be successfully funded.

The Results of the Models

For each project listed above, a representative building in San Francisco was chosen as the site for the EE measure or DG system to be installed. The baseline against which all results are calculated is the status quo, i.e. not implementing any new energy efficiency measures or distributed generation equipment in the building. Each project was modeled to reflect the results that would be expected by installing EE or DG under assumptions consistent with the current environment. The assumptions made, sources of data and the results of these scenarios follow, along with analyses of which variables are driving the results shown.

Energy efficiency and solar PV in a new residential construction project

Building Chosen
A residential unit, such as in the planned Hunters Point redevelopment project

Summary
Deploying a combination of energy efficient construction and photovoltaic generation in San Francisco's new residential construction has several monetizable benefits. Practical financing can be made available through an Energy Efficient Mortgage. Additionally, PG&E's primary residential rate structure (Rate E-1) provides a directionally correct incentive for both EE and PV, and the combined effect of implementing both on the scale modeled would be to eliminate the use of all but the lowest-cost power.

Background
Installing EE or the combination of EE and DG in new residential construction is appealing for several reasons. First of all, in a new construction project of any scale, the cost of saved energy can be cheaper than in a retrofit project. This is because instead of replacing still-functioning equipment, purchasing energy efficient equipment in the first place avoids the capital cost of the less-efficient alternative. This can be illustrated with an example of upgrading from incandescent

light fixtures to more efficient modular fluorescent fixtures. In a retrofit project, because existing fixtures are being replaced, the cost of saved energy is the entire cost of the new fixtures. In a new construction project, on the other hand, the cost of saved energy would be the incremental cost of the fluorescents over the cost of the incandescent fixtures. Secondly, in addition to the direct value of saving energy, second- and third-order effects can reduce the capital costs of other equipment within the home. For example, increasing the efficiency of appliances and lighting reduces the waste heat that enters the home. This in turn reduces the cooling load and makes it easier to eliminate the capital expenditure that would be needed for air conditioning.

Additionally, installing energy efficiency measures in new construction instead of as a retrofit can save installation costs. For a retrofit, any installation costs are incremental costs that must be added to the costs of saved energy. This is not the case in new construction, where these costs would be incurred regardless of whether it is energy efficient equipment that is being installed or not. Furthermore, the costs of installing energy efficient measures are in most cases no higher than installing the standard equivalents. In the case of installing a PV system, the array can be installed at the same time as the roof, saving some of the installation cost relative to retrofitting. Finally, in multi-family residential units such as the Hunters Point redevelopment project, economies of scale are achievable that can further push down these costs. Retrofit projects in the residential sector, on the other hand, are done on a unit-by-unit basis.

A frequent barrier to the implementation of EE and DG is providing financing for the capital cost of the measures. In new residential construction, this barrier can be reduced by financing the measures with inexpensive debt by adding the expenses to the overall cost of the house in the form of an increased mortgage. Qualifying for an increased mortgage to cover such expenses may be a problem for some homebuyers, particularly those with low and medium income levels, due to the limiting factor of their debt-to-income qualifying ratios.

An Energy Efficient Mortgage (EEM) can solve this problem in many cases, however. After mortgage payments, energy costs are often the second-highest expense that homeowners face. Reducing these bills through energy efficiency or distributed generation is the equivalent of increasing the homeowner’s net income. A lender offering an EEM acknowledges this effect by increasing the debt-to-income qualifying ratio of the potential homeowner, often from 28% to 30%. This allows individuals who purchase energy efficient homes to receive a larger mortgage than they might qualify for if they were purchasing a standard house, without requiring an increased down payment. An EEM could allow the amount financed to increase until the resulting marginal mortgage payment each payment period equals the amount by which energy bills are reduced for the same period.

EEMs are offered by a wide variety of lenders, both public and private. The U.S. Department of Housing and Urban Development (HUD) offers an EEM through approved lenders. The cost of improvements under this program must not exceed the larger of $4,000 or 5% of the property value (up to $8000). Fannie Mae also offers an EEM that can cover up to 100% of energy improvements, up to 5% of the home’s value for new construction.[66]

[66] http://www.efanniemae.com/hcd/single_family/mortgage_products/eem.html)

In order for a new residential construction project to qualify as a candidate for Energy Efficient Mortgages, the builder must first design the building to use a certain amount less energy than a comparable baseline building. The builder must then put the home through a verification process, in which it is inspected as a means to ensure that the necessary energy savings will be achieved. The home is then qualified for purchase under an EEM.

Assumptions and Sources of Data

Project Financial Investor	Homeowner
Financing Mechanism	100% debt in the form of increased principle for a 30-year mortgage
Debt Rate	6%
Debt Term	30 years[67]

Based on research by Consol Energy Consulting, the SFPUC provided estimated capital costs of the efficiency measures and annual energy consumption, both with and without efficiency measures and a PV system, on a per unit basis. The measures outlined would produce savings in end uses that are coincident both with system peak hours (such as air conditioning and lighting) as well as system off-peak hours (such as washers and dryers). For this reason, the savings were distributed over the hours of the year in proportion to baseline energy use.

Results

There are several possible ways to market and structure the purchase of a home with an EEM. These options are analyzed here, including the net present values (NPV) that the various stakeholders would receive from such a project. The NPVs are expressed in terms of the incremental value that the stakeholder would receive in comparison to purchasing a standard home with no energy efficiency measures or PV system.

Energy Efficiency Alone: The initial assumptions are that the builder passes on all incremental unit costs to the homeowner without markup, and that the homeowner pays for these costs by financing them within an EEM. It is also initially assumed that no EE rebates are available.

Stakeholder	Project NPV
Homeowner's NPV:	+$8,953
Builder's NPV:	Unchanged
PG&E's NPV:	($4,677)

Under these assumptions, the homeowner's electric bill is reduced by $60 per month, an amount greater than the incremental mortgage payment of $12 per month, resulting in a positive NPV for

[67] The energy efficiency equipment lifetime is assumed to be 20 years, consistent with cost data used. No energy savings are assumed during the last 10 years of the mortgage.

the project. PG&E experiences a net loss from such a project, due to the loss of revenue from the energy that it would have sold to the residence, had no energy efficiency measures been installed. For the sake of this analysis, we are assuming that this will not serve as a barrier to the implementation of such projects. PG&E will be able to make incremental, system-wide price increases over time to make up for these losses.

Energy Efficiency, With Currently Available Rebate: Through PG&E's Residential Rebate Program, EE rebates currently would apply to this project, and are likely to apply in the near future.[68] This program provides rebates on a variety of measures that promote energy efficiency. The measures applicable to this project as modeled are:

Table 50. Rebates Available from PG&E for Energy Efficiency Measures

$1 for each CFL under 20 Watts	x 37 lights =	$37
$0.15 / sq. ft. for attic and wall insulation	x 1513 sq. ft. =	$227
$100 for efficient whole house fans	x 1 fan =	$100
Total estimated rebate available for a unit in the Hunters Point Redevelopment:		$364

Taking these rebates into account, and assuming that the builder passes the full value of the rebate on to the buyer in the form of a lower price for the house, the homeowner's NPV will increase by the amount of the rebate, with no effects on the results of the other stakeholders:

Stakeholder	**Project NPV**
Homeowner's NPV:	+$9,317
Builder's NPV:	Unchanged
PG&E's NPV:	($4,677)

Energy Efficiency With a Photovoltaic System: Adding a PV system increases the value to the investor, compared to only installing energy efficiency measures. The following results are the returns that each stakeholder would realize in comparison to installing neither energy efficiency nor a PV system. We again assume that the builder does not charge an additional premium to the homebuyer, other than passing on the incremental capital cost. Also, we assume that rebates on both EE and PV equipment are available[69]:

Stakeholder	**Project NPV**
Homeowner's NPV:	+$10,689
Builder's NPV:	Unchanged
PG&E's NPV:	($5,772)

[68] http://www.pge.com/003_save_energy/003a_res/index.shtml
[69] Rebate levels for EE are assumed as described above. The rebate for PV is assumed to be $3.40 / Watt, the level expected between July 1, 2004 and December 31, 2004.

The result is an incremental annual mortgage payment of $29 per month for the homeowner, with savings that again more than compensate for this increase: $84 per month. Thus, adding a PV system provides the homeowner with an additional $1,372 of net present value, compared to installing energy efficiency measures alone. The rest of this analysis assumes that both energy efficiency measures and a PV system are installed.

It is worth noting that a principle driver of this project's success is that the combined effect of the EE and PV for the home is to eliminate the use of all but the lowest-cost power. PG&E's residential rate for electricity (Rate E-1) is a tiered rate structure, where energy use in each tier is charged at an increasing rate. Homeowners pay the lowest rates in Tier 1, which is defined as all usage between zero and a certain level. As of October 2003, the Tier 1 rate is $0.126/kWh. PG&E's Rate E-1 has five such tiers. In the base case (with no energy efficiency or PV system), a housing unit such as in the Hunters Point redevelopment would have energy usage going into Tier 4 (which is billed at nearly $0.24/kWh as of October 2003) eleven months of the year. This creates an annual average cost of energy of over $0.16/kWh.

By installing energy efficiency measures, nearly all usage in Tiers 3 and 4 is eliminated. The average cost of energy over the year is reduced to just under $0.13/kWh. Adding a PV system to the EE measures, the home uses energy only in Tier 1 in eleven months of the year. In one of these months, June (when the PV's capacity factor is highest), the 1.2 kW PV system produces enough energy to entirely eliminate their month-long billable energy use from PG&E. The resulting year long annual cost of energy drops to $0.126/kWh, the same as the Tier 1 rate alone. The combined effect of the EE and PV is therefore to eliminate the use of all but the lowest-cost power. Because the level of savings assumed to be realized by the EE measures (3,515 kWh per year) and the amount of energy produced by the PV (2,242 kWh per year) eliminate nearly all of the highest-cost energy, additional savings through energy efficiency or a larger PV system will have diminishing returns, compared to the results shown above.

Assumptions Regarding the Reception of Rebates

The rebates for both the PV system and the EE measures could be claimed either by the builder or the homeowner. Assuming that the builder passes on the cost of the equipment, net of rebates, to the homeowner, both builder and homeowner will see the same financial result regardless of who receives the rebate.

On the other hand, there might be a marketable benefit to the builder of passing the entire cost of the EE measures and PV system on to the homeowner, and letting the homeowner receive the rebates. This will not affect the homeowner's net present value, but it would effectively provide the homeowner with a loan that could be spent on other purchases. Assuming that the mortgage rate is lower than the interest rate on a bank loan, this may be appealing to the homeowner.

Depending on the lender that provides the Energy Efficient Mortgage, there may be a cap on the dollar value of measures that can be covered, as described above. If financing the cost of the entire PV system exceeds this cap, the builder will need to pay for the system and take the rebate. Also, the builder will be eager to recoup the cost of some of the investment, thereby giving an incentive to keep the rebate. For these reasons, the rest of this analysis assumes that the builder takes the rebate.

Sensitivity to Capacity Factor of the PV System

The data used for PV output came from a test site that the SFPUC set up at the Southeast Waste Water Treatment Plant.[70] The data show an annual solar capacity factor of about 21%. The Hunters Point redevelopment, being on the same side of the Bay, is assumed to have similar conditions to this site. Figure 65 shows the sensitivity of the results to this assumption. The net present values shown correspond to the effect of the PV system alone, without energy efficiency, and assume that the builder does not add any other costs.

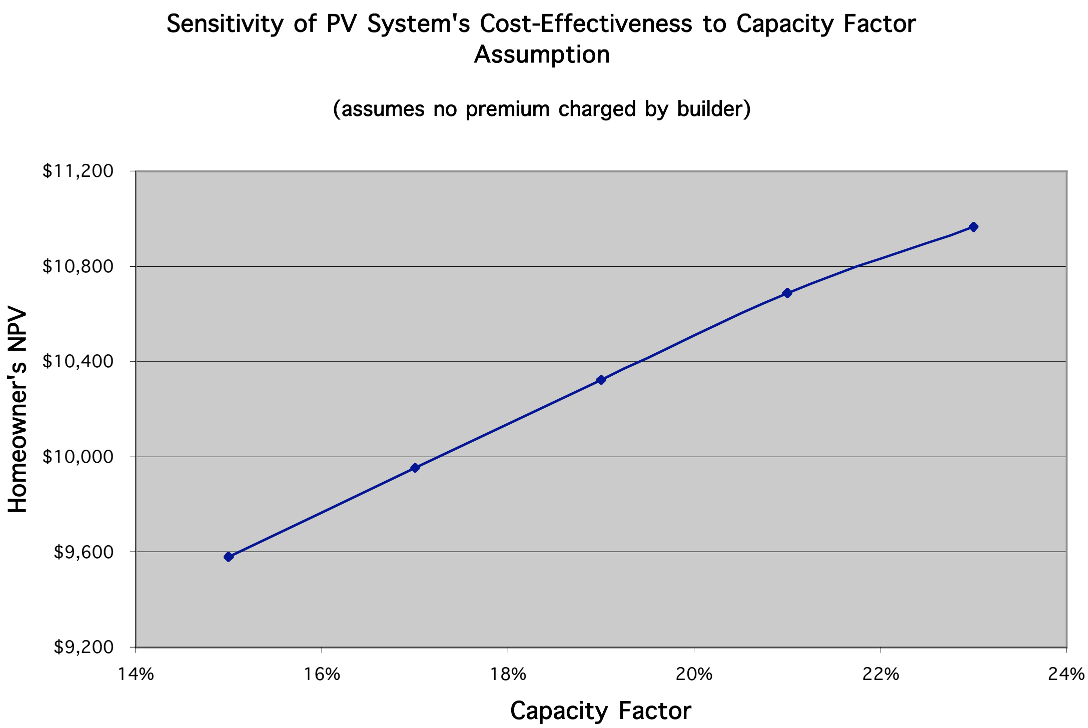

Figure 65. Sensitivity of homeowner's present value benefit to PV capacity factor

Sharing Value Between the Builder and the Homeowner

Because of the significant upside available to the homeowner from purchasing an energy efficient home with a PV system, the builder would be able to take some of this upside, thereby creating a win-win situation and giving the builder an incentive to build such homes. We do not suggest a single optimal way to share the savings, as it will depend on the market and on the builder's preferences.

If the builder charges an extra $2000 for the house, the homeowner still realizes considerable benefit, while the builder receives an incremental $2,000 (pre-tax) revenue, which results in an after-tax incremental return of $1,160 (assuming 42% combined State and Federal tax rate) as shown in the following comparison:

[70] http://www.solarcat.com/sfsolar/main.htm

Stakeholder	Project NPV
Homeowner's NPV:	+$8,689
Builder's NPV:	+$1,160

This results in an incremental annual mortgage payment of $41 per month for the homeowner, and savings on the energy bill of $86 per month.

The homeowner would still be able to break even if the builder were to charge as much as $10,700 above what would have been charged for a home with no EE or PV, as shown below.

Stakeholder	Project NPV
Homeowner's NPV:	+$0
Builder's NPV:	+$6,206

Figure 66 shows the results of the builder charging various premiums on the initial cost of the home.

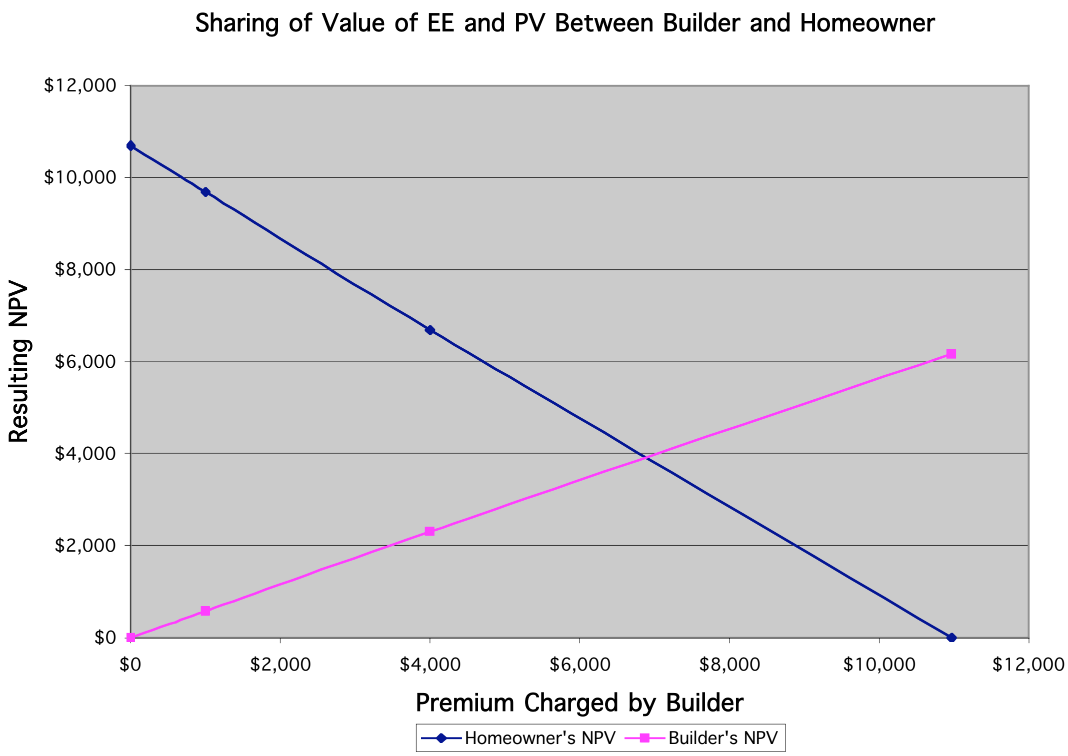

Figure 66. Tradeoff between builder's and homeowner's present value benefit

Sensitivity of Results to Mortgage Rate Available

Figure 67 shows that the financial viability to a homeowner of a project like this is also highly dependent on the available mortgage rate.

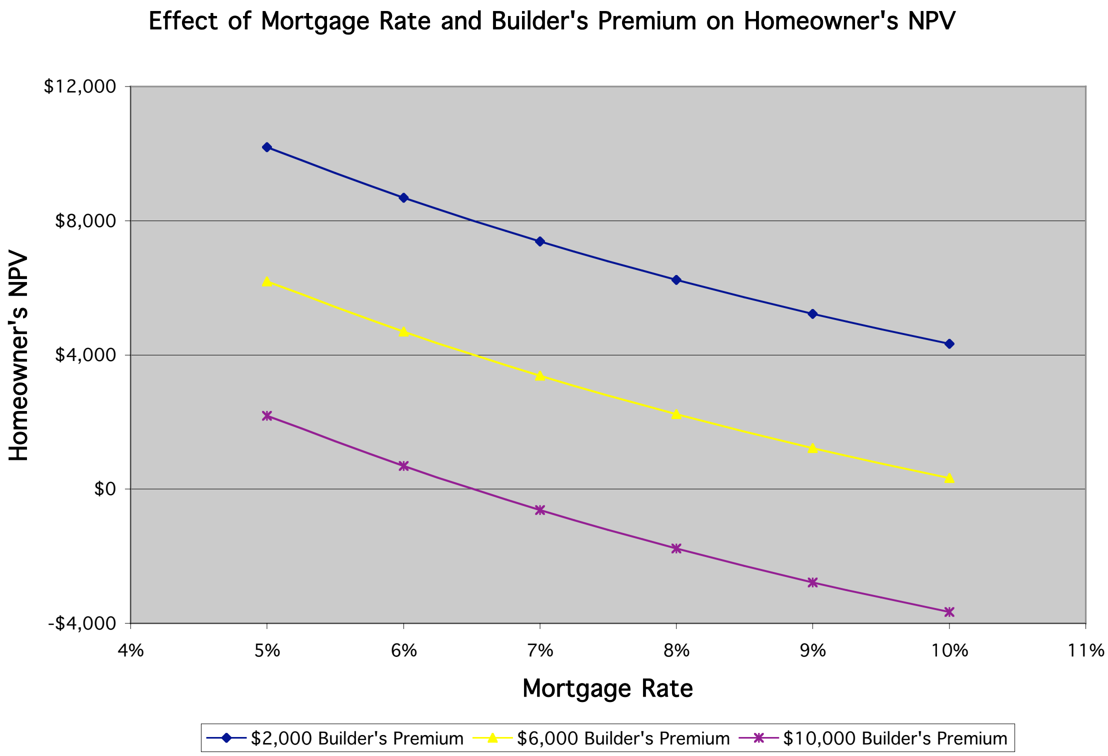

Figure 67. Sensitivity of homeowner's present value benefit to interest rate

Recommendations

The builder should market the homes' energy efficiency and PV systems as qualities that differentiate them from other housing options. These qualities may increase the appeal of the units to potential buyers. This appeal can be leveraged through targeted marketing that focuses on qualities such as reduced environmental impact, the "high-tech" appeal of generating one's own electricity, as well as the financial benefit.

Also, in order for potential buyers to qualify for an Energy Efficient Mortgage, the builder may need to hire an energy-rating auditor to verify that the home will indeed save energy as promised. The audit cost can be passed on to the homeowner and in most cases can be financed via the mortgage (up to $200). In order to increase the market for such homes, builders should provide potential homeowners with information about Energy Efficient Mortgages, including qualification requirements and participating lenders. The City can help by supporting building energy certification and code training for inspectors (see the following section on *Programs and Policy Needs*).

The City could also stimulate the demand for energy-efficient new homes with or without PVs by producing and distributing education materials. Such information could be distributed both to potential homeowners and to builders for further distribution. Creating a "Building Green" membership would be useful, with a database that includes the names of builders, engineers, architects, contractors, lenders, appraisers, and inspectors. This would help homeowners who are interested in owning an energy-efficient home, and it would enable individuals and firms in these industries to connect with each other. All this information can be made available to the public via multiple channels, including print and online, and should also be provided to real estate agencies.

In order to further encourage the construction of such homes as these, the City should create incentives for builders to exceed Title-24 standards by installing extra insulation and efficient lighting and appliances in new homes. Incentives could include expediting the building permitting process for homes meeting a certain level of energy efficiency. The City could also provide builders with other types of educational materials or databases, such as recommended measures and appliances, vendors, rebates available and a list of lenders offering Energy Efficient Mortgages. Another potential benefit to builders would be for the City to direct similar marketing and education efforts at real estate agents, who serve as the critical interface between the housing market and the potential homeowner.

The City should also streamline the PV installation and interconnection permitting process as a way to encourage builders to include PV systems on new construction. If the process of obtaining permits, approvals, and filing for the rebates is too involved and complicated, the builder will be less likely to install PV. To make this process easier, the City could develop brochures and information in other media detailing step-by-step instructions on the installation of a PV system. The permitting process could also be streamlined make electrical and building permits available at the same location, preferably with little waiting time between dropping off the permit application and receiving approval. If approval is not granted the first time, help should be provided on how to fix the system and achieve approval.

The results shown by the financial model should be roughly applicable to new construction in the commercial sector as well. However, in commercial buildings, the building owner may not have the same incentives for reducing energy bills as does a residential homeowner. The owner of a commercial office building, for example, will often pass all the energy costs on to the tenants. In such cases the building owner would be unable to recoup the costs of the energy efficiency measures without developing a contract with the tenants, such as a shared savings contract. Additionally, commercial entities are not likely to qualify for debt at terms as favorable as homeowners. These complications are further described in the section on the *Energy Efficiency in a Commercial Building* model.

Energy Efficiency in a municipal General Account customer building

Building Chosen
San Francisco General Hospital

Summary
Installing energy efficiency measures at General Account customer buildings such as the General Hospital can yield considerable value for the SFPUC and the City of San Francisco as a whole. While it is possible for private investors to receive a positive return and rather short payback with this project, achieving such results would require the SFPUC to give up all direct value that they would realize from this project. It would also require the SFPUC to provide the firm with 50% of the project's capital cost in the form of City bond funds. Thus, for projects at General Account customers, it is recommended that the SFPUC act as the investor. Also, the SFPUC and

the General Hospital, both City agencies, should overcome the barriers to considering the benefits of efficiency projects from the perspective of the City as a whole.

Background and Assumptions
The General Hospital was chosen because it has the second highest electric load among the City's General Account customers, behind only the Municipal Railway. Muni was not chosen due to the singular nature of the end uses comprising its load (largely the propulsion of trains).

Financial Investor	Financing Mechanism	Debt Rate	Debt Term
SFPUC	City bond funds	5%	20 years
Private Firm (ESCo)	25% debt, 75% equity	8% (ROE: 15%)	10 years

The SFPUC provided total yearly energy consumption as well as an estimate of energy efficiency potential for interior lighting in the General Hospital. The lighting load profile was constructed from aggregated data for hospitals in the U.S.[71] The installed cost of the efficiency measures was derived from the Xenergy report used in our efficiency potential analysis.

Results
In this and all projects involving municipal buildings, there are two potential investors: the SFPUC itself and a private firm such as an energy services company (ESCo). The effect that such a project would have on the City will depend on which of these parties invests.

SFPUC as investor: The following results assume that the value of the energy saved at the General Hospital is kept entirely by the Hospital (i.e. no shared savings contract is in place).

	Stakeholder	Project NPV ($000)
SFPUC as Investor:	SFPUC	- ($ 364)
	General Hospital	+ $ 1,767

The SFPUC experiences a net loss under this arrangement because the energy that the Hospital no longer purchases is ultimately sold at various rates, the weighted average of which is not high enough to make up for the combination of the capital cost of the EE equipment and the loss of revenue from the Hospital. However, from a citywide perspective, this is a short-sighted view of the project. Instead, the project should be considered with the understanding that the General Hospital and the SFPUC are both City agencies. From this perspective, the City of San Francisco as a whole realizes a NPV of $1.4 million from this project.

However, organizational barriers within the SFPUC and the Hospital may prevent consideration of the two entities as a combined unit. The incentive structure or basis of evaluation for the staff of both the SFPUC and the General Hospital may require each to seek a positive return for their own organization for any project. In order to create a win-win situation for both organizations independently, the project must be modeled as if the SFPUC were a traditional ESCo investor,

[71] EPRI Commend Database

taking a percentage of the energy savings that the General Hospital realizes. For example, if the General Hospital keeps 10% of the value of the saved energy, both stakeholders' net present values would be positive.

Stakeholder	Project NPV ($000)
Homeowner's NPV	+$1,226
Builder's NPV	+$177

The range of possibilities for sharing this value is shown in Figure 68. Note that for all sharing agreements, the sum of the net present values of the shared savings between SFPUC and the Hospital is the same, $1.4 million.

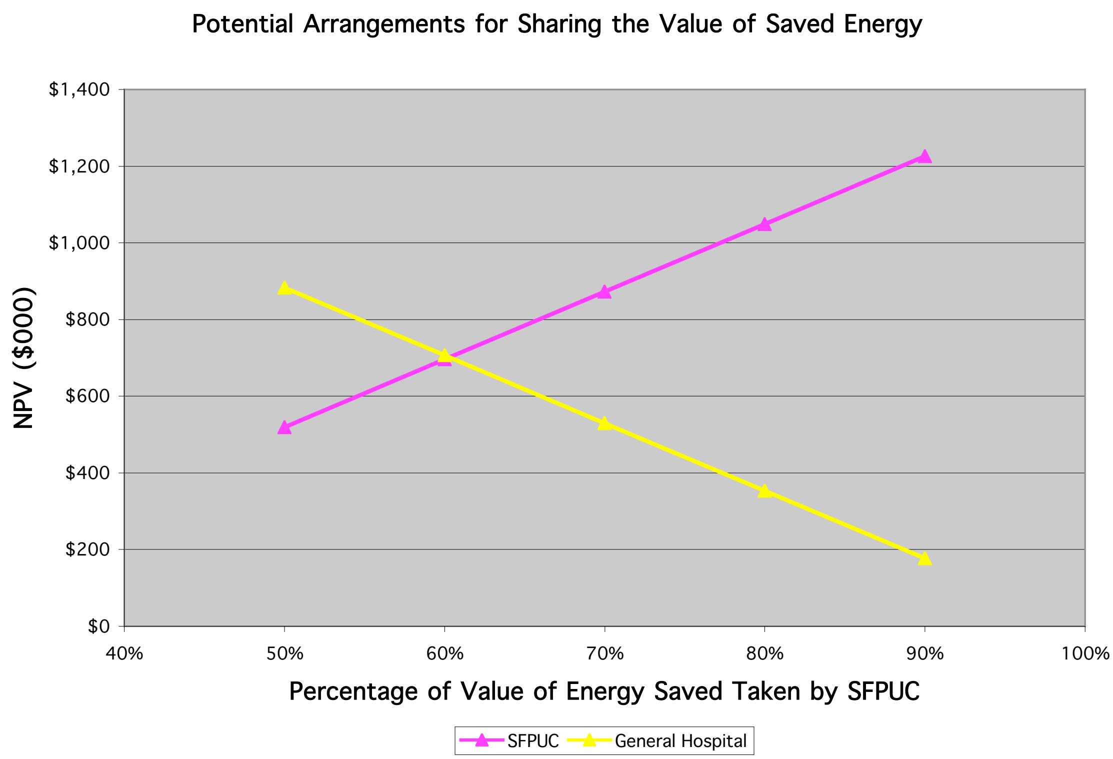

Figure 68. Tradeoff between customer's and SFPUC's present value benefit

Another way for the SFPUC to increase the return that it realizes is through community choice aggregation, a process enabled by AB 117 (see the *Aggregation and/or Municipalization* section). Through aggregation, the SFPUC could increase the number of customers to which it sells power. If enough customers could be aggregated, and if these customers are charged at least $0.062/kWh, the SFPUC would break even on the project, while allowing the Hospital to retain all of the value of the energy savings.

Results for an ESCo as investor: The following results assume that the ESCo earns its return through a shared savings contract with the General Hospital, which is consistent with typical ESCo business models. The Hospital pays a percentage of the value of the saved energy to the

ESCo, while keeping a percentage for itself. The following results assume that the ESCo receives 90% of the value of the saved energy.

	Stakeholder	Project NPV ($000)
ESCo as Investor:	ESCo	- ($ 361)
	SFPUC	+ $ 1,002
	General Hospital	+ $ 177

The share of the value created from the saved energy that the ESCo receives is not sufficient to repay the capital cost of the measures, let alone generate a positive return. This is largely due to the low rate that General Account customers pay. However, the SFPUC would see a considerable net gain of roughly $1 million should an ESCo execute this project. This gain is also due to the fact that General Account customers pay the lowest energy rate of all of the SFPUC's electric customers. Energy saved at this building can be sold by the SFPUC to others, including other municipal customers, the Irrigation Districts and spot market sales. The weighted average price paid by these purchasers of SFPUC power would be higher than the municipal General Account rate, resulting in a net increase in revenue. For the SFPUC to realize the benefits of the involvement of an ESCo investor described above, factors affecting the ESCo's return must be addressed. There are several ways to do this:

1) The City could give the ESCo access to inexpensive debt resulting from the sale of City Bonds from Proposition B. If 25% of the project's cost is financed with this debt, the ESCo's NPV improves to –$285,000. If the City permits the ESCo to finance up to 50% of the project's cost through this low-interest debt, it further improves to –$83,000. Providing this source of debt would have no effect on the SFPUC and General Hospital's returns from this project.
2) The SFPUC could insist that the Hospital accept a contract where the ESCo takes 100% of the value of the saved energy. This would provide the following returns, according to varying levels of City bond money being made available:

Resulting NPV ($000) assuming ESCo receives all value of saved energy			
% of City Bond Money Used for Debt:	0%	25%	50%
NPV for ESCo ($'000)	($312)	($235)	($33)
NPV for SFPUC ($'000)	$ 1,002	$ 1,002	$ 1,002
NPV for Hospital ($'000)	$ 0	$ 0	$ 0

3) The SFPUC could share some of the value that it receives from this project with the ESCo. If SFPUC subsidizes the ESCo's return such that the SFPUC experiences no net effect from the project, the ESCo's NPV for the project becomes positive. Assuming that the ESCo takes 90% of the value of the savings and the following percentages of City Bond money:

Resulting NPV ($000) assuming SFPUC subsidizes the ESCo, and that the ESCo receives all value of saved energy			
% of City Bond Money Used for Debt:	0%	25%	50%
NPV for ESCo ($'000)	($48)	$ 29	$ 260
NPV for SFPUC ($'000)	$ 0	$ 0	$ 0

NPV for Hospital ($'000)	$ 0	$ 0	$ 0

The ESCo would realize a positive $260,000 NPV when given access to City bond money in the amount of 50% of the capital cost. Thus, in order to create a project that is sufficiently attractive to an ESCo, the SFPUC must not only sacrifice all of the direct upside it would receive from the project, but also must lend half the project's cost to the ESCo. Financing the project itself may therefore be a preferable option for energy efficiency projects in General Account customers.

Sensitivity of the City's Return to the Amount of Energy Saved Through Efficiency Measures
As described above, the benefit to the City of San Francisco as a whole is equal to the combination of the effects on the General Hospital and on the SFPUC. As with all energy efficiency projects described here, various levels of energy savings are possible in this or any building. The average cost of the savings realized may increase as more energy is saved, as shown by the efficiency supply curve (Figure 21). Table 51 shows the relationship between energy savings achievable at various costs and the combined SFPUC and General Hospital net present values that would result.

Table 51. Present value benefit as a function of energy savings and cost

Energy Saved (kWh/yr):	**1,000,000**	**2,000,000**	**3,000,000**	**4,000,000**	**5,000,000**
Capital Cost of Savings: ($/annual kWh saved)			**City's NPV**		
$0.30	$269	X	X	X	X
$0.35	$219	$862	X	X	X
$0.40	$169	$762	$1,355	X	X
$0.60	$31	$362	$755	$1,148	X
$0.80	$331	($38)	$155	$348	$541
$1.00	($431)	($438)	($445)	($482)	($459)

Note: Cells marked by an 'X' indicate unrealistic levels of savings and cost levels.

Realistic Savings Potentials

Highest Achievable Financial Return

This chart demonstrates that in the case of the General Hospital, the highest financial return occurs by implementing measures that save between 3 million and 4 million annual kWh. This project assumes 3.2 million annual kWh are saved at an average cost of $0.425 per annual saved.

Sensitivity of the City's Return to the Availability of Hydro-Electric Power at Hetch Hetchy:
In any EE or DG project at a municipal customer's building, the amount of hydropopwer available in a given year will affect the net present value that the SFPUC realizes from the project. Compared to a year with a historically average amount of rainfall, a dry year would increase the value that the SFPUC derives from an EE or DG project by as much as 9%. The occurrence of a wet year would have a smaller positive effect on the value, or no effect at all.[72]

[72] Where 'low' is defined as the lowest 15% of historical values, and 'high' as the highest 15% of historical values.

To understand these effects, it is necessary to consider the contractual obligations that the SFPUC operates under with regard to energy sales. These relationships are explained in the section on *electricity service obligations and District power contracts*, and in Appendix A. To summarize, in dry years, the SFPUC must buy energy from the market to meet its obligations to serve both municipal customers and the Irrigation Districts (until 2008). Some purchases come at times of peak system-wide demand, when prices are high. Saving or generating energy at municipal facilities therefore offsets these spot purchases, generating a higher value. In normal and wet years, minimal or no purchases are made from the market. Thus, saving or generating energy would result in marginal sales to the Irrigation Districts or to the market. In a wet year, more energy is sold to the market. Assuming that the Hetch Hetchy power can be dispatched selectively, the City can generate electricity when it can sell it to the market at the highest prices. Thus, the value of EE and DG would increase slightly, compared to a year of average rainfall.

Energy Efficiency in a municipal Enterprise Account customer building

Building Chosen
The San Francisco International Airport (SFO)

Summary
Both the SFPUC and an ESCo have the potential to realize considerable gains by installing energy efficiency measures at municipal Enterprise Account customer buildings such as SFO. However, when an ESCo invests, the SFPUC realizes a sizable loss. There are potential methods for reducing this loss, but these are unlikely to be realized. For this reason, it is recommended that the SFPUC itself should invest in this project.

Background and Assumptions
SFO was chosen because its annual electric load makes up two-thirds of the electric load of all municipal Enterprise Account customers. There is potential for energy efficiency in this facility, making it an attractive subject to model. Members of the SFO staff provided the hourly load data used in this model. We estimated the lighting load profile based on these data and discussions with SFO staff. The potential for lighting energy efficiency, as a percentage of the total yearly energy use, was provided by the SFPUC.

Financial Investor	Financing Mechanism	Debt Rate	Debt Term
SFPUC	City bond funds	5%	20 years
Private Firm (ESCo)	25% debt, 75% equity	8% (ROE: 15%)	10 years

As with all projects in municipal buildings, the project investor could be either the SFPUC or an ESCo. In either case, to realize a return for the investor, the airport would need to sign a contract stipulating payment of some percentage of the energy savings to the investor, for at least part of the lifetime of the efficiency measures. Also, for the project to be successfully implemented, a share of the savings realized must remain at the airport, as opposed to being passed on to the investor. SFO is a particularly complicated facility because energy is used both by the Airport

Authority (a municipal entity that overseas its operation), and by the various airport tenants. Airport tenants include food vendors, freight companies, the airline companies and others.

The tenants are in a position to block the successful completion of such a project, should they not be offered a share of the savings. Specifically, for the investor to install efficiency measures throughout SFO, the Airport Authority and the tenants would need to cooperate, at least in terms of granting access, etc. Moreover, after an efficiency project is implemented, the Authority and the tenants would be paying for saved electricity that they are not using. For such a proposition to be acceptable, monitoring and verification will be needed to show the tenants that they are paying less overall for comparable energy services than they would with no efficiency measures.

Results
The following results assume that the investor takes 90% of the value of the saved energy.

GENERAL RESULTS	Stakeholder	Project NPV ($000)
Private company (ESCo) as investor:	ESCo	$4,213
	Airport	$1,708
	SFPUC	($18,618)
(These results correspond to a payback of 5 years to the ESCo)		
SFPUC as Investor:	SFPUC	$4,179
	Airport	$1,708

SFPUC as Investor: If SFPUC receives a large share of the energy savings, this project is a good investment for the City. SFPUC and SFO could share the value of this project in several ways. Figure 69 shows that SFPUC must receive at least 77% of the energy savings to break even. If such a contract can be negotiated, this project would be attractive to the SFPUC.

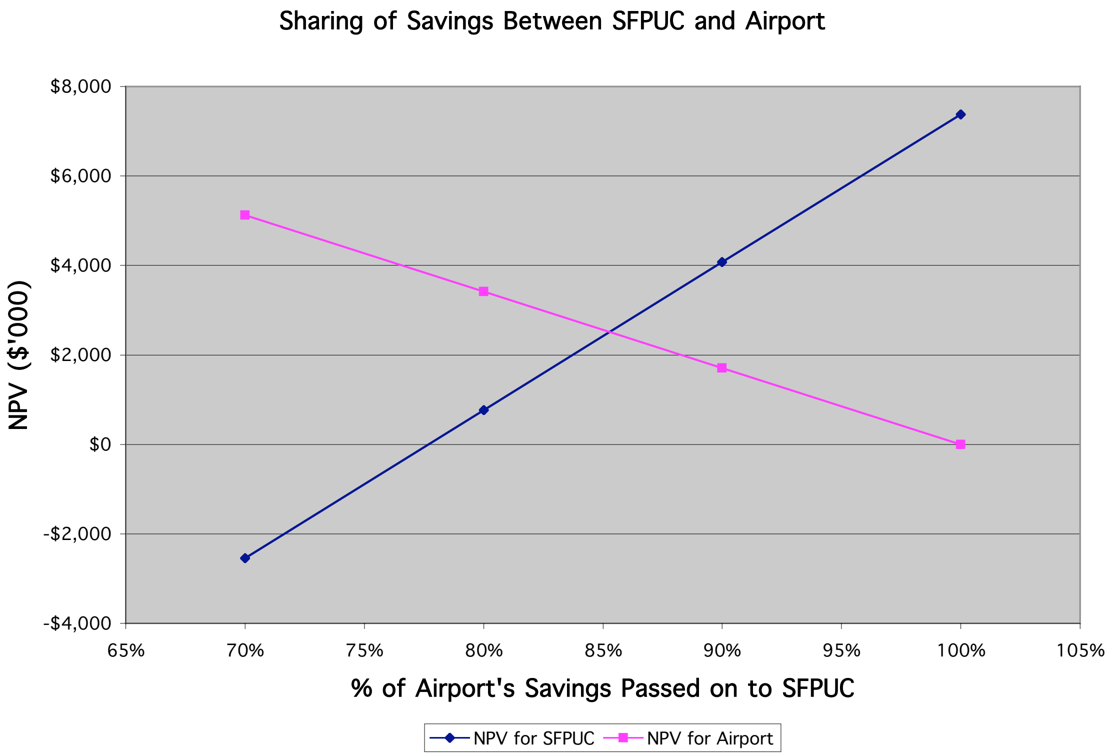

Figure 69. Tradeoff between airport customer's and SFPUC's present value benefit

ESCo as investor: The critical component that will determine whether an ESCo could be financially successful in a project such as this is how the value of the saved energy is distributed between the three parties involved – the airport, the SFPUC and the ESCo itself. As mentioned above, the ESCo will need the airport to keep some of the value. The effects of various sharing agreements on each party's NPV are shown in Table 52 and Figure 70.

Table 52. Present value benefits as a function of energy savings sharing

% of energy savings value taken by ESCo:	100%	90%	80%	70%	60%	50%
Investor (ESCo)'s NPV	$5,100	$4,213	$3,326	$2,439	$1,552	$665
Investor's payback	4 years	5 years	6 years	7 years	9 years	13 years
Airport's NPV	0	$1,708	$3,416	$5,124	$6,832	$8,540
SFPUC's NPV	($18,618)	($18,618)	($18,618)	($18,618)	($18,618)	($18,618)

Note: Assumes no revenue sharing to SFPUC

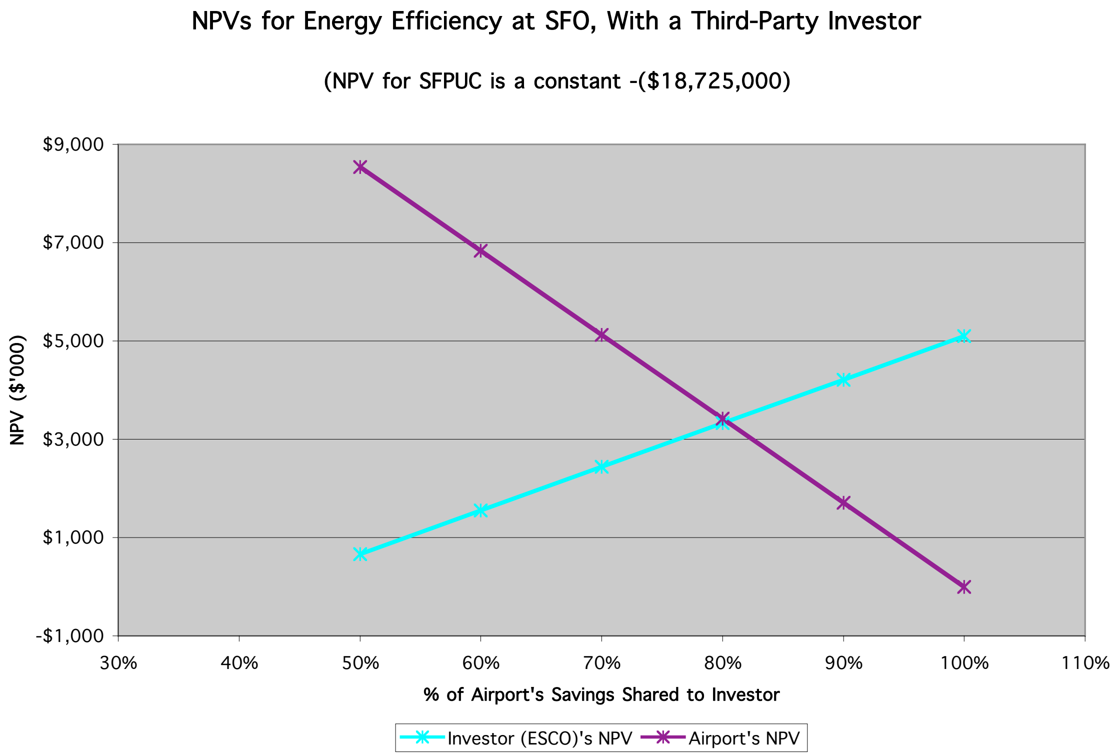

Figure 70. Tradeoff between airport customer's and ESCo's present value benefit

These results show that an ESCo's return from this project may not result in a sufficiently short payback. By keeping 90% of the savings, the ESCo would achieve a 5-year payback, which is too long for many firms. One way that the SFPUC could address this problem would be to provide the ESCo with City bond money, as described in the *Energy Efficiency in a Municipal General Account Customer* project above. This would have a positive effect on the ESCo's NPV, as illustrated in Table 53.

Table 53. Effect of Access to City Bond Funds to Finance Debt Portion of Investment

Debt Percentage of Total Capital Cost	Source of Debt	Debt Rate	Resulting NPV	Payback (years)
25%	Private	8%	$4,213	5
25%	City Bond	5.25%	$4,582	4
50%	City Bond	5.25%	$5,566	3

Note: Assumed shared savings - ESCo takes 90% of project's value

However, a significant barrier exists to an ESCo financing this project - the SFPUC realizes a considerable loss (over $18 million), as shown above. There are several reasons why this loss occurs. First of all, the SFPUC receives a high value for the power that it sells to Enterprise Account customers like SFO (slightly over $0.10/kWh on average, plus a demand charge). Energy savings therefore result in less energy being sold at this high rate, less revenue from demand charges, and therefore lower profits for the City. The power that the City would have sold to SFO can be sold to other customers, but most other customers to whom the SFPUC sells power pay less than the Enterprise Account rate and do not pay a demand charge. The difference between these rates is the main driver of the financial loss to the SFPUC.

There are several ways to mitigate the loss that the SFPUC realizes when an ESCo invests in energy efficiency at SFO. One option would be to require the ESCo to pass a percentage of its revenues on to the SFPUC. However, the ESCo's revenue isn't high enough to do this without eliminating any incentive for doing the project. To eliminate any negative effect to the SFPUC, the ESCo would need to share revenue until its NPV would be reduced to $109,000, a 19-year payback.

A second option that would enable the SFPUC to recoup the lost revenue from sales to SFO would be to aggregate additional customers to whom it could sell energy at a high rate. As Figure 71 shows, if energy could be sold at just over $0.12/kWh to enough customers, the SFPUC would break even. This is a difficult goal to achieve, as this rate would be higher than any rate at which the SFPUC currently sells energy to its customers. Aggregating residential customers, however, could provide a potential vehicle for realizing rates at this level.

Another way for the SFPUC to reduce their loss (in this or any other project in a municipal building) would be to provide a percentage of the equity portion of the ESCo's capital cost. This would depend on whether such investments are permitted for the City. In the case of this project, supplying one third of the ESCo's equity would increase the SFPUC's NPV by nearly $4 million. Note that this is not enough to make up for the lost revenues it experiences, however. The effect of this financing mechanism on the ESCo would be a reduced NPV, but the same payback time.

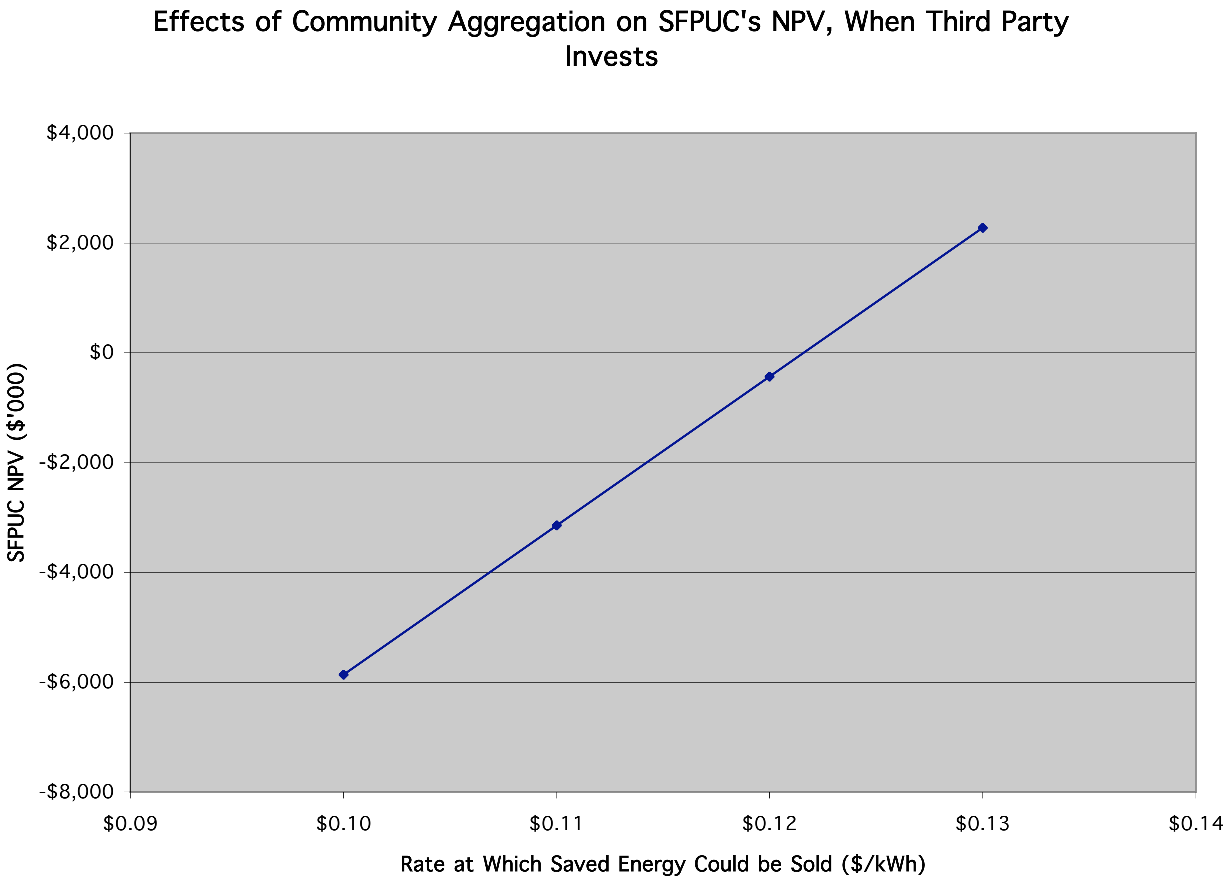

Figure 71. Sensitivity of SFPUC present value benefit to value of marginal kWh

Given the above assumptions, it would be difficult for the SFPUC to engage an ESCo for this project without experiencing a net loss. For this reason, it is recommended that the SFPUC itself invest in energy efficiency at SFO and other municipal Enterprise Account customer buildings.

Distributed Generation at a municipal Enterprise Account customer

Building Chosen
Photovoltaic (PV) System at San Francisco International Airport (SFO)

Summary
This project would provide attractive returns for a commercial third party (such as an ESCo), with a rapid payback. The net effect on the SFPUC, however, is a loss of revenue. This loss is expected to occur regardless of whether an ESCo or the SFPUC would finance the project. There are several ways to mitigate this loss, including community aggregation and/or bundling the installation of a PV system with more cost-effective energy efficiency measures. The benefits of a clean, mostly peak-coincident PV generation system could still merit implementation, if the City deems the environmental and energy planning benefits to be worth the financial loss.

Background and Assumptions

Photovoltaics were chosen as the distributed generation technology to model due to several factors, including their scalability and peak-coincidence, as well as the financial incentives that are available. Also, a renewable energy technology provides distributed generation that is entirely emission free. SFO was chosen as a location because of the ample roof space available for a PV system, its bayside location (more sun than the often-foggy ocean side), the presence of a cogeneration system already serving thermal loads (reducing cogeneration potential), and the fact that a PV project at SFO is already being discussed at the SFPUC. The assumed capacity of the system is 1 MW, but the results are scalable to any system size within the restrictions of the rebate. We assume the same 21% capacity factor as in the residential PV model discussed above.

Like all municipal Enterprise Account customers, SFO purchases electricity from the SFPUC, paying both electricity usage and demand charges according to PG&E's E-20P rate. We assume that airport tenants will not notice any change in service or in their electricity bills after a PV system is installed. The customers pay the investor, whether a commercial third-party or the SFPUC, the same rate for power produced by the PV system as they would have paid otherwise, including a demand charge in proportion to the power production during times of peak demand.

Financial Investor	Financing Mechanism	Debt Rate	Debt Term
SFPUC	City bond funds	5%	20 years
ESCo	25% debt, 75% equity	8% (ROE: 15%)	10 years

Results

The rate that SFO and other Enterprise Account customers pay for electricity is among the highest of all non-residential end users in San Francisco. This makes the installation of a PV system at this location relatively attractive to a private third-party investor. However, for the same reason, the SFPUC faces a formidable barrier as an investor in this project. Unlike energy efficiency projects, installing a PV system would not change the amount of energy that would be sold to that particular customer. Rather, the net effect of installing a PV system would be to make more SFPUC power available for sale to the power market or to other customers. Thus, the power generated by a PV system is not valued at Enterprise Account rates, but rather at the weighted average of the market price and the other customers' rates. The resulting value of the power produced by a PV system would not be sufficient to cover the capital cost of the PV system under current conditions.

General Results	Stakeholder	Project NPV ($000)
Private company (ESCo) as investor:	ESCo	$673
	Airport	$0
	SFPUC	($2,851)
(These results correspond to a payback of 3 years for the ESCo)		
SFPUC as investor:	SFPUC	($1,727)
	Airport	$0

ESCo as Investor: An ESCo would receive a positive NPV from this project, with a 3-year payback. This result is due to a combination of the following incentives that are available to commercial parties installing PV systems:

- Rebate: Through PG&E's Self Generation Program, the maximum of $4.50/watt or 50% of total project cost is available for systems between 30 kW and 1 MW.[73]
- Tax advantage: A Federal income tax deduction equal to 10% of the capital cost of the PV system (net of rebates) is available.
- Front-loaded, PV-specific depreciation schedule: PV systems qualify for an extra-accelerated depreciation schedule that is not applicable to other capital purchases. Assuming that the ESCo has sources of profit from other projects or business activities, the remaining capital cost of the PV system after the rebate can be depreciated very rapidly thanks to this schedule. The positive effect that this schedule has on an ESCo financing this project is shown in Figure 72.

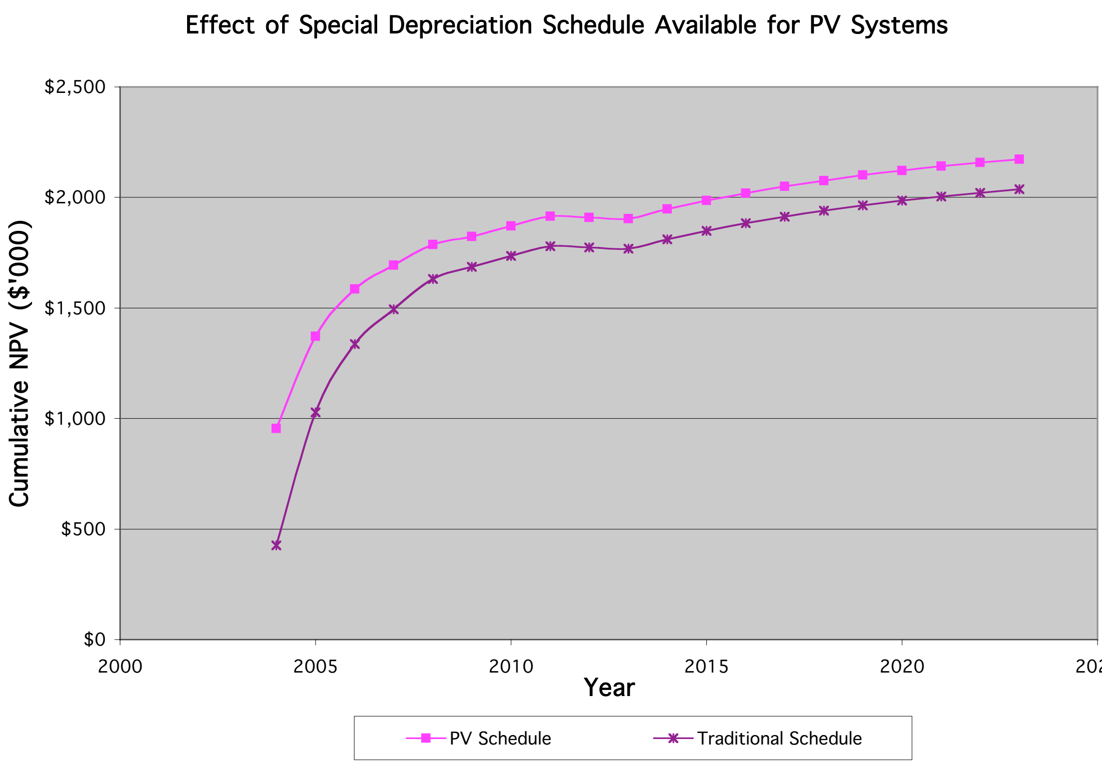

Figure 72. Sensitivity of present value benefit to depreciation schedule

SFPUC as Investor: As described above, the value of the kilowatt-hours generated by the PV system is a combination of market prices and the rates paid by the customers to whom the SFPUC is contractually obligated to sell power. This weighted average rate is not high enough to result in a positive return for the SFPUC for this project. Another reason that the SFPUC cannot realize the same returns that a commercial firm can is that the tax-based incentives listed above are not applicable to tax-exempt organizations such as the SFPUC.

[73] http://www.pge.com/selfgen/

Addressing Barriers to the SFPUC
For the SFPUC to realize a net gain from this project, the current conditions would have to change. Possible solutions include:

- Bundle a PV system with efficiency measures: As described in the previous model, by implementing energy efficiency at the Airport, the SFPUC has the potential to realize a net present value of over $4 million. This would be more than enough to offset the loss that would result from installing a PV system. If both projects were evaluated and considered as a single, bundled project, it would still be an attractive proposition for the SFPUC, resulting in a NPV of nearly $2.5 million.
- Community aggregation: For the SFPUC to break even should an ESCo finance this project, the SFPUC would need to aggregate customers to whom it could sell the power generated for an average of $0.15/kWh. In the case of the SFPUC financing the project, the average rate at which they would need to sell marginal power would be $0.11/kWh. Note that both of these values are much higher than the $0.062/kWh needed in energy efficiency projects for General Account customers.
- Capture capacity value: The current structure of the California power market does not provide value for capacity, which is only valued in the Ancillary Services Market. If the sale of on-peak capacity to the market were rewarded, energy saved or generated at municipal facilities would effectively be worth a higher value than at present. This would improve the economics of efficiency and distributed generation projects.

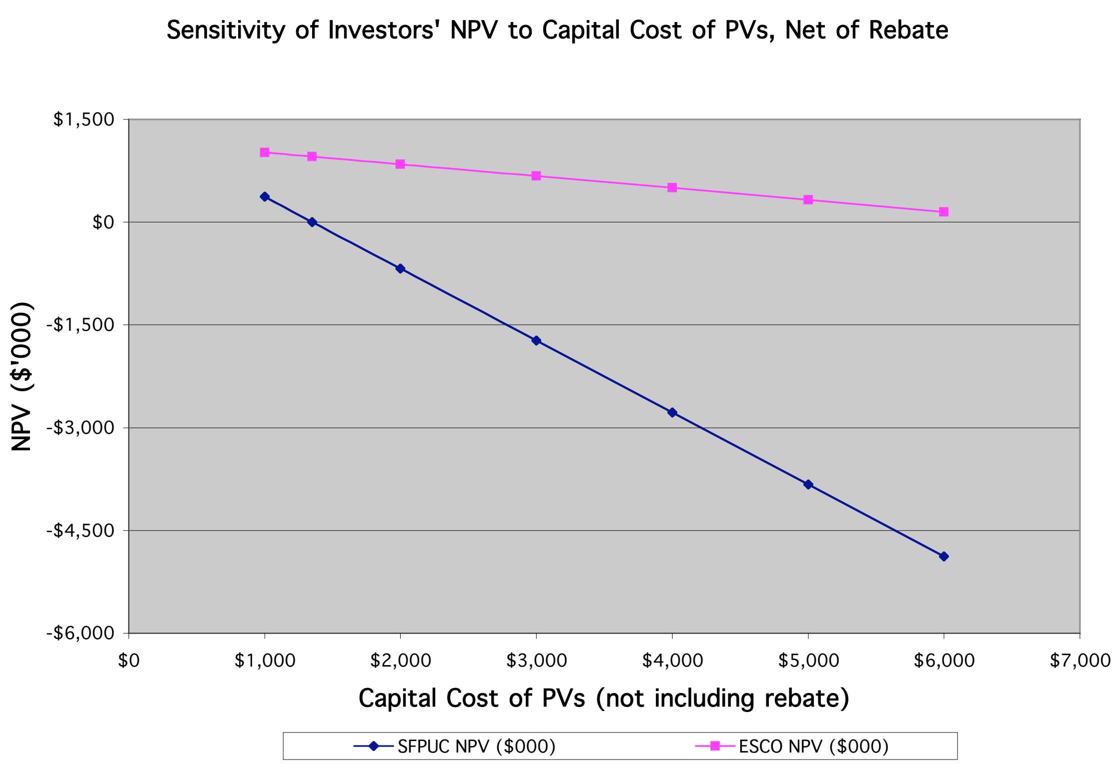

Figure 73. Senistivity of present value benefit to PV capital cost

Effect of PV Capital Cost and Rebate on Investor

Variables such as the capital cost of PV systems or rebates available are not expected to improve enough in the near future to reverse the losses that the SFPUC would face. For the SFPUC to break even on a PV project, the after-rebate cost of the system would need to be reduced to $1,350 per kW, as shown in Figure 73.

Figure 73 also shows that the NPV for an ESCo is less sensitive to the capital cost of the PV system than it is for the SFPUC. Even if no rebate is available for PV systems (at a capital cost of $6,000 per kW), an ESCo could get a positive return from this project, though the payback would be too long (11 years). This difference is because of tax breaks, such as depreciation and the 10% Federal tax credit, which are available to a private company but not to a City agency.

Energy efficiency in a commercial building

Building Chosen

A large office building in San Francisco

Summary

Installing efficiency measures in office buildings has been the primary source of business success for ESCos to date. Sizable returns with short paybacks (under four years) often result. However, the ESCo's return is vulnerable to the building's level of occupancy. Also, the potential for selling a project at all is often compromised by split incentives between project participants. Thus, to realize the large efficiency potential in this sector, the City should implement policies designed to encourage such projects. These policies can involve regulatory mandates, market incentives for ESCos to pursue efficiency projects, or measures to increase the demand for energy efficient commercial space from both potential building owners and tenants.

Background and Assumptions

Project Financial Investor	Private Energy Service Company (ESCo)
Financing Mechanism	25% debt, 75% equity
Debt Rate	8%
Debt Term	10 years

Real Energy provided hourly building energy use and thermal load data for a generic 60,000 ft^2 building. The Xenergy report provided the values used for lighting as a percentage of energy use, as well as the economic savings potential for lighting within commercial office buildings in this area. Note that the cost values provided by the Xenergy report reflect a high existing penetration rate of energy efficient technologies, particularly lighting, in San Francisco office buildings.

Our model assumes that an ESCo is the project investor and that the ESCo negotiates a shared savings contract with the building owner. In this arrangement, the ESCo receives income from the building owner in the form of a portion of the monetary savings from reduced electricity use, as well as a portion of the reduction in demand charges.

The primary concern in energy efficiency projects in commercial buildings is the split incentives that can occur between building tenants and owners. Building owners who do not pay the electric bill will not realize the benefits of installing efficiency measures, nor any return from the time and effort associated with allowing an ESCo to install the measures. Another problem is that, as part of the shared savings contract, the ESCo will be charging for something that "isn't there" (saved energy). Thus, savings must be monitored and verified.[74] Buildings with high tenant turnover will be problematic, as will be large buildings with many tenants. The ideal building type for an ESCo would be large owner-operated buildings, followed by buildings with a small number of long-term tenants, or buildings with individual electric meters for each tenant.

Results

The model assumes that the ESCo negotiates a shared savings contract with the building owner. Whether the building owner passes savings on to the tenants is irrelevant to the results. The primary drivers of the project's financial success are the share of the saved energy that the ESCo is paid by the owner and the occupancy rate of the building over the course of the project life.

Table 54. Present value benefit as a function of occupancy and ESCo share of savings

Building Occupancy	Percentage of Savings Taken by ESCo:	90%	80%	70%
100%	Building NPV ($000)	$99	$194	$290
	ESCo NPV ($000)	$523	$425	$327
	ESCo Payback (years)	4	4	5
	PG&E NPV ($000)	($590)	($590)	($590)
90%	Building NPV ($000)	$89	$175	$261
	ESCo NPV ($000)	$431	$343	$255
	ESCo Payback (years)	4	5	6
	PG&E NPV ($000)	($531)	($531)	($531)
80%	Building NPV ($000)	$79	$155	$232
	ESCo NPV ($000)	$340	$261	$183
	ESCo Payback (years)	5	6	7
	PG&E NPV ($000)	($472)	($472)	($472)
70%	Building NPV ($000)	$69	$136	$203
	ESCo NPV ($000)	$248	$180	$111
	ESCo Payback (years)	6	7	9
	PG&E NPV ($000)	($413)	($413)	($413)
60%	Building NPV ($000)	$59	$117	$174
	ESCo NPV ($000)	$156	$89	$39
	ESCo Payback (years)	7	9	12
	PG&E NPV ($000)	($354)	($354)	($354)

[74] The International Performance Monitoring and Verification Protocol describes approaches that can be used for monitoring and verification of savings (www.ipmvp.org).

The shared savings arrangement is determined by the ESCo's business model and negotiations with the building owner. The issue of occupancy rate, however, is largely beyond the control of the ESCo. In most cases, the ESCo would install energy efficiency equipment throughout a building. However, buildings are unlikely to be fully occupied over the course of their life. Because the ESCo only earns revenue when the efficiency measures are used (i.e. when the lights are on), low occupancy will reduce the revenue from the investment. Table 54 shows the sensitivity of the ESCo's and the building's NPV from the project to these two variables.

With high occupancy levels, an ESCo can afford to share a higher percentage of the value of the energy savings. As occupancy drops below 80%, however, an ESCo would need at least 90% of the savings in order to achieve a project payback of five years or less. For the remainder of this analysis, a 90% occupancy level and 90% share of the savings to the ESCo are assumed.

Depreciating vs. Expensing the Capital Cost of Energy Efficiency Measures

It is worth noting here that all projects discussed so far have assumed that the cost of the energy efficiency equipment would be treated as a capital expenditure by the ESCo, and therefore depreciated. Depending on specific applicable accounting standards, the ESCo may also be able to expense some or all of this cost in the first year, a practice that substantially increases the net present value that is realized by the project.

Depreciating (Modified Accelerated Cost Recovery System – MACRS – method):

Stakeholder	NPV ($000)
ESCo	$429 (4-year payback)
Building	$88
PG&E	($531)

Expensing:

Stakeholder	NPV ($000)
ESCo	$482 (3-year payback)
Building	$88
PG&E	($531)

Recommendations for the SFPUC

Particularly in weaker economies when occupancy rates in commercial buildings tend to drop, an energy efficiency project such as this may become a risky venture for an ESCo. The City and/or State government can improve the project economics that the ESCo would face in several ways, by addressing the needs of the building owner, the potential tenants, and the ESCo itself.

In order to reduce the risk that ESCos would face during times of lower building occupancy, the City could provide them with a loan to cover a percentage of the capital cost of the measures in a similar way to what was described in the municipal building projects above. For commercial buildings, City bond money resulting from Proposition H could potentially be made available. This would have a higher interest rate (6.5% assumed) compared to tax-exempt bonds such as Proposition B bonds (5.25% assumed), but the latter are designated for use in City facilities only. Providing debt to ESCos will have minimal impact if the ESCo could get a bank loan at an interest rate close to the bond rate. For example, by replacing an 8% bank loan with a 6.5% bond, the ESCo's NPV would improve by only $4,000 (assuming 25% debt, 75% equity split).

Increasing building owners' demand for the service can also encourage energy efficiency projects. This could be accomplished either through mandates or incentives. An example of a mandate would be to implement an energy performance standard for commercial buildings, requiring a level of energy efficiency beyond the Title-24 standard. Incentives could come in many forms, including accelerated permitting for building retrofit or new construction projects, or a tax break on a percentage of rental income for building owners whose buildings meet particular levels of energy efficiency.

Finally, requiring building owners to disclose the energy performance of their buildings would enable potential renters to create an increased demand for efficient commercial space. This would require an increased level of transparency regarding the link between the rental price and the energy performance of a building. If, for instance, building owners were required to show a metric of the building's energy efficiency, such as an average monthly energy cost per square foot of space rented, potential tenants would be able to factor this information into rental decisions. This information could be shown on the lease agreement or other visible document. Requiring such information would have the most effect in a weaker economy, during a renters' market.

Distributed generation in a commercial building

Building and DG Technology Chosen
The same building modeled for *Energy Efficiency in a Commercial Building* was modeled for this distributed generation project.

Summary
This project generates a positive net present value for the investor, but because of its high initial capital cost, the project's payback time is ten years. Also, the ESCo's financial return is sensitive to the size of the rebate available. The City should promote policies that encourage ESCos to install the most efficient and cleanest distributed generation technologies available.

Background and Assumptions
Real Energy provided data on equipment efficiency, capital and operating costs, electric and thermal load data on an hourly basis, as well as many of the details of the business model included in the modeling of this project.

Business Model
There are multiple business models possible for the installation of DG systems in commercial office buildings by an ESCo. This analysis assumes a contract stipulating that the building owner will pay to the ESCo the same rates for all energy delivered by the ESCo, as they would have to pay the utility otherwise. This includes electricity rates, gas rates, demand and any other charges that may apply. All energy (both electric and thermal) that the ESCo provides from its generation technology or the use of captured waste heat would then be sold to the building at these rates, displacing a percentage of the energy that the building would otherwise purchase from the utility. The ESCo agrees to match the lowest rates for which the building would qualify, should utility

rates change, or should new sources from which to purchase energy become available in the future.

The building owner then leases space to the ESCo for placement of the DG system. One benefit to the building owner is that this can be otherwise non-rentable space, such as in the basement or on the rooftop. The rent that the ESCo pays for this space is set at a percentage of the value of the energy services that the ESCo provides to the building. The net effect of the exchange is that the building owner pays a fixed percentage less for the energy services that it receives from the ESCo, compared to the previous utility service.

Interconnection
This model assumes that there is no new interconnection between the building and the electric grid, i.e., electricity generated by the DG system is never sold to users outside of that building. The building remains connected to the grid, and the generator is sized to maximize its capacity factor, within applicable regulatory constraints. This means that during hours of peak building demand, some electricity is still being purchased from the grid to meet the building's load.

PURPA
This project, a DG project involving cogeneration, is bound by operating constraints defined by the Public Utility Regulatory Policy Act (PURPA), supplemented by California's "Rule 21," which governs DG. These constraints are:

- At least 5 percent of the facility's total annual energy output shall be in the form of useful thermal energy.
- Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output must equal not less than 42.5 percent of any natural gas and oil energy input.[75]

The project as modeled limits the number of hours during which the generators produce electricity, in order to ensure PURPA compliance.

Technological
The technology modeled is a natural gas-fired reciprocating engine with 30% electrical efficiency and an installed capital cost of $2,450/kW, including all development costs and transaction costs.

Financial

Project Financial Investor	Private Energy Service Company (ESCo)
Financing Mechanism	25% debt, 75% equity
Debt Rate	8%
Debt Term	10 years

[75] http://www.pge.com/002_biz_svc/selfgen/selfgen_incent_qanda.shtml#howpaid

Results
While the ESCo realizes a sizable net present value from this project, the 10-year payback may be too long for most developers.

Name of Stakeholder	Project NPV ($000)
ESCo	$436 (10-year payback)
Building	$353
PG&E	($3,502)

Recommendations
In order to shorten an ESCo's payback period, the City could increase the per-kilowatt rebate available for distributed generation technologies. PG&E currently offers a rebate equal to the lesser of 30% of the installed cost or $1000 per kilowatt. The sensitivity of an ESCo's return to this rebate, assuming that the capital cost remains the same, is shown in Table 55.

Table 55. Sensitivity of ESCo financial return to rebate assumption

Net Rebate Available ($/kW)	ESCo NPV ($000)	ESCo Payback (years)
$500	$185	13
$1,000	$436	10
$1,500	$687	7
$2,000	$938	5

In order to reduce City-wide vulnerability to power outages, the City could encourage PG&E to facilitate interconnection between these DG sources and the grid, and to enable these generators to continue to run and power the host building when the grid is down (i.e., to operate in an "islanding" mode). As discussed in the section on *Overcoming Barriers to DG*, this may require technology changes to ensure the protection of equipment and the safety of utility workers.

Combined energy efficiency and distributed generation in a commercial building

Building and DG Technology Chosen:
This model analyzes the hypothetical combination of the energy efficiency and DG examples in commercial buildings described above. The same building is assumed.

Background and Assumptions:

Project Financial Investor	Private Energy Service Company (ESCo)
Financing Mechanism	25% debt, 75% equity
Debt Rate	8%
Debt Term	10 years
Installed Generation Capacity	1.5 MW

By analyzing the relative performance of an energy efficiency project, a distributed generation project, and a combined efficiency and DG project, we conclude that the three projects result in roughly similar NPVs. However, the project capital costs of the DG alone and the combination projects are considerably higher than the efficiency project, and these costs has a significant effect on the length of the project's payback for the investor. This difference in capital cost is what causes the long (10 year) payback that an ESCo implementing a DG project would experience (See in Figure 74).

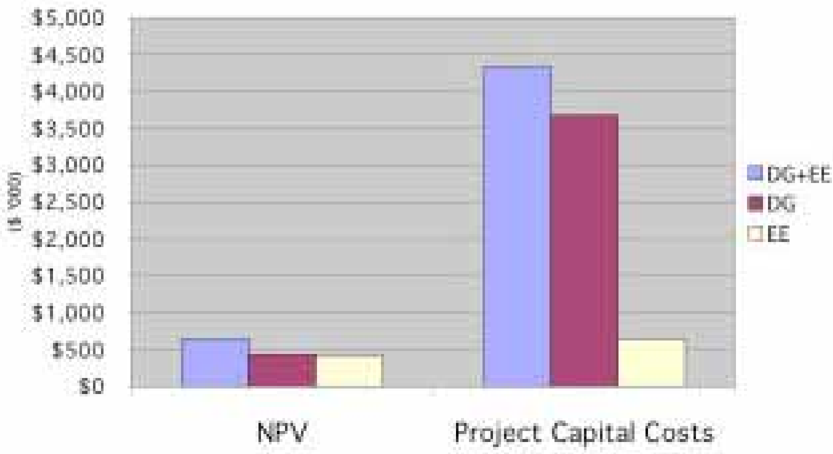

Figure 74. NPV and Capital Costs of Commercial Models

Every dollar invested in the efficiency project produces $0.63 of positive net present value, while a dollar of stand-alone DG produces only $0.12 of positive NPV. The combination project produces $0.15 of positive NPV for every dollar invested.

The resulting internal rates of return (IRR) of these projects are shown in Figure 75. Again, the IRR for efficiency alone is considerably higher than for DG alone or the combined efficiency and DG project.

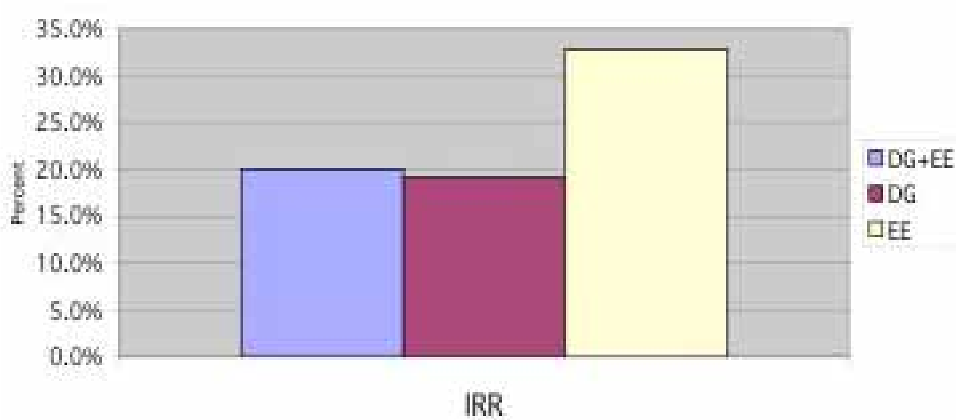

Figure 75. Internal Rate of Return for Commercial Models

Figure 76 analyzes the differences between NPVs for stand-alone DG and the combined project.

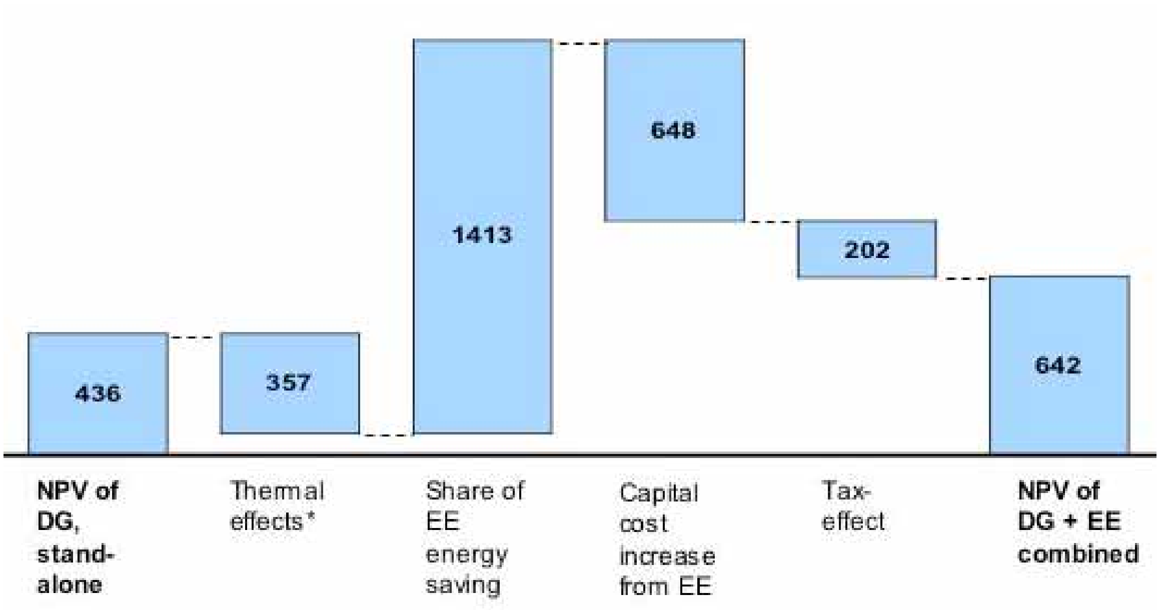

Figure 76. Breakdown of NPV from Adding Efficiency to a Commercial DG Project

PROGRAM AND POLICY NEEDS

The energy resource portfolios that result from the ERIS process depend heavily on the success of energy efficiency measures and programs to limit energy demand in the City. Also, the scenarios that achieve the City's long-term goal of eliminating central, fossil-fired generation rely strongly on the development of distributed co-generation, including fuel cell technology.

Although many EE and DG technologies are now cost-effective, and we expect their economic performance to improve in the future, there are many barriers to investment in these options, some of which are illustrated in the project-level analysis above. Therefore, success in implementing any of the ERIS portfolios is likely to depend on the City's ability to reduce these barriers and encourage investment in EE and DG by the private sector, PG&E and the City.

Even if all the financial mechanisms described above can be harnessed to accelerate investment in efficiency and DG, there are still important categories of energy efficiency opportunities that can be captured through public policies and programs that enhance public-private cooperation. In the short term, the City needs to work with PG&E to capitalize on the State of California renewed commitment to make energy efficiency an essential part of the State energy program. Public goods charge (PGC) funding can be applied to energy efficiency programs, especially in the commercial sector, that are tailored to the City's needs.

Other innovative programs, which have proven successful in other states, can help San Francisco overcome barriers to energy efficiency in specific market segments, including difficult to reach segments such as existing multifamily housing. These are summarized in this section and described in more detail in Appendix C. Some of the recommended programs include:

- *Green buildings program* for new construction to encourage, recognize, and eventually require high-performance green design, measured for example by the U.S. Green Building Council's LEED ratings, in new buildings (examples include Austin TX and Seattle WA).
- *Commissioning and building operator training* for commercial and municipal buildings, to capture cost-effective efficiency and performance improvements in the operation and control of buildings (examples include Portland OR and Southern California), supported by training of operations staff to identify efficiency opportunities and implement efficient practices.
- Turnkey programs to install efficient technology in *multifamily rental and low-income housing*, in which residents cannot afford or lack incentive to invest in energy efficiency, by providing building audits and technical assistance, financial incentives, and contractor screening (examples include Vermont and Oregon).
- *Pay-As-You-Save* (PAYS), an innovative program to finance customer costs of efficiency and DG investments, which are repaid through the (energy or water) utility bill, spread over time and offset by energy savings, avoiding the initial-cost barrier that limits customer investment in energy efficiency and DG generally (examples include New Hampshire and Connecticut).
- *Building energy certification* to recognize and encourage efficiency improvements in new and existing buildings, and to provide a basis of comparison for buyers, realtors and lenders.
- Energy *code training for building inspectors* to improve the compliance and enforcement of voluntary and mandatory building energy codes, including the California Title-24 standard.

- Demand response programs, using critical peak pricing with automated control and two-way, real-time communication technology to enable customers to limit their power demand for short periods during critical periods when electricity supply is short and/or expensive.

Energy Efficiency Programs

There are at least two reasons why San Francisco should assume a more prominent role in providing a coordinated, comprehensive efficiency program. First, San Francisco is a unique city with a unique climate, and its energy demand patterns are different from PG&E's system-wide peak demand and average energy consumption patterns. The City has a high concentration of large commercial buildings such as hotels, as well as high-rise residential buildings.

PG&E's system-wide peak is driven by midsummer cooling loads in the California interior, whereas San Francisco's "summer" mild coastal climate yields a summer peak, which can occur between May and October and is only slightly higher than its nighttime winter peak. While residential air conditioning is a key target of PG&E DSM programs and California statewide efficiency policies, most San Francisco residences do not need or own air conditioning. Because of these and other differences, the City's efficiency programs will need to target some end uses other than those of existing utility DSM programs that are designed to address PG&E's system-wide peak.

Second, San Francisco has an in-depth understanding of its own needs, and is arguably in a better position to implement some types of City-specific energy programs than is PG&E or the State. Not only does the City have established connections with other municipal departments, but in light of the recent energy crisis and PG&E bankruptcy, it appears that the City enjoys a higher level of trust from its residents and businesses, especially in activities involving customer interaction. This trust can be helpful in the realization of energy programs by boosting participation rates and recruiting the efforts of local vendors.

However, the City's energy efficiency implementation efforts are complementary, not mutually exclusive, to PG&E's existing and planned future DSM programs. The California PUC has recently ruled that energy efficiency should again become a cornerstone of the State's energy policy, and that utilities should be central to the procurement of energy efficiency measures.[76]

In July 2003 assigned CPUC Commissioner Kennedy issued a ruling that the Commission should continue to pursue energy efficiency programs aggressively in order to reduce California's energy consumption and to make energy efficiency an essential part of the state's energy program. The assigned Commissioner's ruling suggested funding efficiency programs for two-year intervals while the Commission is reviewing longer-term program administration. The ruling proposed to allocate 15-20% of total funds to third parties such as communities and the remainder for utility programs.

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[76] On August 21, 2003, the CPUC adopted Decision (D.) 03-08-067, which included priorities for determining the process and schedule to address the Commission's energy efficiency goals. Specifically, the Commission will "seek to maintain continuity and the stability of currently successful programs (in 2004-2005) to enable the Commission and interested parties to focus on developing an integrated energy efficiency policy framework, including integration of efficiency programs with procurement activities and settling the question of long-term administration, to create a stable platform that will ensure the long-term success of California's energy efficiency programs."

Thus, PG&E will remain the major investor in energy efficiency in San Francisco in the near future. The success of the City's efficiency efforts depends on a good working relationship so that both parties can achieve their goals. For example, SFE uses energy consumption data from PG&E to properly design, implement, and evaluate the success of City-based energy programs. New partnerships with PG&E could rely on the utility's capability to deliver energy efficiency training, program materials, marketing and promotional assistance tailored to local needs, while City agencies such as SFE and other community groups become channels to implement statewide programs. Collaborative PG&E and City programs can capitalize on local understanding of unique community needs while maintaining the utility's system-wide economies of scale.

While San Francisco is well positioned to implement energy programs, success also depends upon a number of other human factors such as political will, organizational will, organizational capability, and cross-agency cooperation. The City has agreed to retire Hunters Point power plant in 2005 and requested the CAISO to elaborate the minimum required conditions to close the plant and maintain the integrity of electric service in the City, such as through the San Francisco Electric Reliability Project.

Program funding sources

Public funding for energy-related programs is appropriated through State legislation in the form of public purpose program funds. The funds are allocated to various state energy entities, including the California Energy Commission (CEC), the investor-owned utilities such as PG&E, and local governments such as the City of San Francisco. About 80 percent of the funds are collected from utility ratepayers in the form of a public goods charge (PGC), which is collected from utility customers' bills to support public programs for energy efficiency, low-income services, renewable energy, and energy-related research and development. Approximately 1.0 percent of each customer's electric bill and 0.7 percent of each natural gas bill supports the public goods charge. Legislation (SB 995), signed in September 2000, extended the public purpose funding for ten more years, through December 31, 2011. The bill authorized $5 billion for energy efficiency, low- income, renewables, and research and development programs over that time period. Energy efficiency programs receive the largest portion of the funds, and in contrast to the other programs, must meet cost-effectiveness criteria.

In 2002-2003, twenty percent of PGC funds were set aside for "third-party" proposals from private- for-profit, non-profit, and public entities to provide local programs. (Partly) as a result, the SFE and PG&E are jointly implementing energy efficiency programs designed specifically for San Francisco. The goal of the San Francisco pilot Peak Energy Program is to reduce City peak demand by 16 MW or more by 2006.

Additional City funding initiatives for energy and energy efficiency include Proposition B, also known as the Solar Revenue Bond, which was passed by the voters in November 2001. Proposition B allows the City to issue up to $100 million in tax exempt public debt to pay for the installation of solar panels, wind turbines and energy efficiency measures on City-owned property. Savings from reductions in the City's energy bills will be used to repay the bonds. As discussed earlier, determining the value of these savings is not simple, as it depends on a number of variables including the renegotiation of the City's contracts with the irrigation districts in Modesto and Turlock.

Proposition H was also passed by the voters in November 2001 and amended San Francisco's City Charter. Proposition H is an unlimited revenue bond authority for the San Francisco Board of Supervisors to issue revenue bonds to finance or refinance renewable energy or energy-efficiency technology at any facility. Thus, the H Bond Authority may be used for private sector as well as government facilities. It does not require that bonds be repaid from bill savings.

To date, the city has not yet issued bonds under either Proposition B or H. The SFPUC is working to determine the necessary criteria for financing projects and issuing bonds under Proposition B. Among other requirements, SFPUC needs to establish a formal bond rating as a separate business entity from the City government.

The City can also finance efficiency projects via performance contracting, where energy service companies (ESCos) install efficiency measures on a turnkey basis and receive payment as a share of the energy cost savings achieved. Performance contracting provides a way for public agencies to use future energy savings to finance and purchase energy-saving equipment, installation, and maintenance services, without using their own capital budget. The City could use ESCos to leverage available public financing and thereby accelerate the implementation of commercial sector efficiency retrofits. To successfully use performance contracting, the City will have to:

- Provide sufficient incentives and performance guidelines to encourage ESCos to make comprehensive efficiency upgrades, beyond the typical "cream-skimming" approach that ESCos use to ensure adequate financial performance;
- Design financing mechanisms to combine private and public-sector financing, as well as State and local incentives if available, in order to increase the amount of financing available and reduce its overall cost at the project level;
- Streamline the process of doing business with the City, in order to attract enough potential vendors to ensure that the City attracts high quality talent at reasonable costs via market competition.

Criteria for success of City energy programs

The City has the potential to be the marketer, organizer, enabler, and recognized authority on energy programs for its residents and businesses, in addition to being a program administrator. As a marketer, the City can leverage its relationships with other organizations as well as the trust of its residents to optimize program participation rates. San Francisco's experience working with neighborhoods can help identify hard to reach areas that require special efforts, and to design specific strategies to ensure high program penetration in these areas.

As an organizer, San Francisco can help residents untangle the web of State, utility, and local energy programs. The City can forge relationships between programs, eliminate or combine redundant programs, and maintain consistency in naming of programs, services, and incentive amounts. The City can help identify opportunities for augmentation or customization of existing programs, so as to maximize energy reduction and minimize cost. The City will need to review its suite of programs to ensure that they support its long-term energy resource plan. An existing agency, such as the energy program of the San Francisco Department of Environment (SFE), could become a one-stop-shop for City residents and businesses seeking energy efficiency information and services.

As an enabler, the City can remove barriers to program participation and provide support to ensure that efficiency programs are clear and understandable for the customer. The City can accomplish this by ensuring that marketing and advertising messages are written simply and clearly and disseminated through appropriate channels; that program rules are simple and complementary to other existing programs; and that the City is available and accessible to answer questions from participating customers.

Forging relationships with vendors of products and services can facilitate the City's efficiency programs. Working with manufacturers, retailers, and equipment vendors to increase the application of energy efficient products, the City can create allies in raising customer awareness and convincing consumers to invest in energy efficient products. Similarly, working closely with architects, designers, engineers, and builders through training, education, and certification can help build a workforce that appreciates that efficient construction can generate greater savings than prescriptive, piecemeal retrofits.

High-value demand-side program recommendations

Details on twenty-three noteworthy demand-side management (DSM) programs offered outside of San Francisco are presented in Appendix C. The programs were selected because they illustrate high-value strategies for the City. Most of the successful programs highlighted employ the type of public-private working relationships discussed above. The programs, organized into new construction vs. retrofits, fall into the following three main customer categories:

- Programs addressing the City's efforts in general,
- Programs addressing the non-residential sectors, and
- Programs addressing the residential sector.

Although many of the program proposals are not new, they are unavailable or not active in San Francisco or the greater Bay Area. On the other hand, several of the programs apply emerging program concepts that have been successfully tested in only a few places in the country. These new program paradigms have the potential to affect significant energy and peak demand reductions in San Francisco. In this section, we describe the programs in terms of strategic program recommendations for the City.

Program recommendations discussed below are summarized in Table 56. Recommended programs are grouped by customer sector, though several programs are applicable to more than one sector. Similarly, Table 56 groups recommended programs according to their applicability to new versus existing construction, though several programs are applicable to both categories. Specific examples of the recommended programs are described in greater detail in Appendix C.

Table 56. Summary of recommended programs for San Francisco

	New Construction	Existing/Retrofit
Municipal	• Green building program • Commissioning • Building energy certification	• Motivating city employees • Commissioning • Pay-As-You-Save (PAYS) • Building energy certification
Commercial	• Green building program • Commissioning • Building operator training • Load control/demand response • Building energy certification	• Commissioning • Building operator training • Load control/demand response • Pay-As-You-Save (PAYS) • Building energy certification • Incentives for gas-fired equipment
Residential	• Green building program • Whole building incentives for multifamily and low-income • Building energy certification	• Energy code training for inspectors • Appliance recycling • Turnkey program for multifamily • Pay-As-You-Save (PAYS) • Building energy certification • Incentives for gas-fired appliances

Motivating public employees: City energy challenge

City or other government employees, as users of government facilities, are in a good position to provide suggestions for increasing efficiency. The City of Portland's Green Team (highlighted in Appendix C) provides an example of how the local government can motivate employees to find efficiency opportunities, and how government departments can be organized to realize these efficiency opportunities. Such programs provide both reduced energy consumption in municipal buildings as well as an opportunity for city employees to improve their own work environment. The Green Team, for example, promotes activities that save resources and money, identifies ways to improve workplace sustainability, and provides a forum for employees to share ideas and get things done.

Green buildings program for new construction

Achieving greater efficiency in San Francisco's existing building stock remains a challenge that requires dedication, creative thinking, and public support. Even with periodic improvements to California's Title 24 building energy standard, the City can take additional steps to ensure that efficiency opportunities in new building construction are not lost. Alliances with the building, engineering, architectural, and construction trades to capture efficiency opportunities in new building design and construction can reduce dependence on in-City generation, electricity imports, and volatile gas markets.

High performance buildings can deliver more benefits than simply energy cost savings. Additional financial benefits of efficient green buildings include:

- Higher building valuation,
- Lower water costs,

- Lower vacancy rates,
- Potentially higher rents,
- More favorable financing terms,
- Greater worker productivity[77]
- Higher student test scores[78]
- Lower operations and maintenance costs,
- Lower insurance premiums[79]

Currently, one of the most successful green buildings program in the country is that administered by Austin Energy in Texas (see Appendix C). However, Seattle was the first municipality in the country to adopt a green building standard. This standard is based on the U.S. Green Building Council's LEED (Leadership in Energy and Environmental Design) Silver rating and applies to larger (over 5000 ft^2 occupied space) construction projects.

A recent study of 33 LEED-rated green buildings indicates that the average cost premium was less than 2%, or about $\$4/ft^2$, and readily paid back by energy cost savings and the other financial benefits listed above.[80] Interestingly, the more aggressive LEED Gold-rated buildings showed a smaller cost premium than lower rated LEED Silver buildings, suggesting that green building designers are finding ways to exploit cost-saving design synergies in the high-rating buildings.

In San Francisco, City agencies such as SFPUC or SFE could become the community's primary resource for green building practices. They could produce educational materials on green building practices, conduct educational seminars for the professional community on building practices and energy code compliance, and act as a resource on efficient building practices for the general public. They could inform the professional community and the public on available incentives, preferably those tied to a sustainability metric such as building certification or rating.

Building commissioning for existing (and new) commercial construction

Even in the most efficiently designed buildings, no technology can be guaranteed to save energy if it is not installed correctly or not being operated as designed. Most existing commercial buildings were never commissioned when they were initially built, and the lighting and HVAC

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[77] Rensselaer Center for Architectural Research. 1992. *Using Advanced Office Technology to Increase Productivity*. The study documented productivity gains from daylighting, access to windows, and a view to a pleasant landscape. Employees in the new building were also supplied with individual controls that allowed them to adjust temperature and other conditions in their work place. Productivity gains in the new building increased by 16%. The personal controls accounted for 3% of the gain.

[78] Heschong Mahone Group. 1999. *Daylighting in Schools*. August 20. The study was conducted on behalf of the California Board for Energy Efficiency. The researchers analyzed test scores for 21,000 students in 2,000 classrooms in Seattle, Orange County, CA, and Fort Collins, CO. In Orange County, students with the most daylighting in their classrooms progressed 20% faster on math tests and 26% faster on reading tests in one year than those without daylighting. For Seattle and Fort Collins, daylighting was found to improve test scores by 7-18%. Effects were observed with 99% statistical certainty.

[79] Well-designed energy-efficient buildings, using technologies such as demand-controlled ventilation, can provide improved indoor air quality, which can reduce both insurance costs and potential owner liability for occupant illness claims.

[80] Kats, G., et al., *The Costs and Financial Benefits of Green Buildings*, Report to California's Sustainable Building Task Force, October 2003.

equipment and system controls do not operate to their full potential. Even buildings that functioned correctly initially will still go "out of tune" in time as moving parts age, sensors drift, and occupants change lighting or thermostat settings. Performance is more at risk if building managers have not been properly trained to operate the systems in their facilities.

Commissioning new facilities, *retro*commissioning existing buildings, and *continuous* commissioning have gained wider recognition as highly cost-effective strategies for achieving energy-efficient and health-promoting buildings, with simple payback times of 1.5 years or less (see Portland and Southern California Edison's commissioning programs in Appendix C). Because commissioning involves the proper tuning and adjustment of various building systems, based on instrumented building performance diagnostic testing, it often requires only minimal capital investment. The City could implement a formal commissioning program for municipal buildings and work with PG&E to spread the practice wherever possible in the commercial sector.

Institute PAYS in San Francisco

The Pay-As-You-Save™ (PAYS®) program has been a highly successful pilot in New Hampshire. PAYS is an innovative payment mechanism that is flexible enough to be adapted to a wide variety of applications. It ensures that customers only pay for the energy service that they want and that customers will save more than an efficiency measure's cost. It does not necessarily make a project more cost effective. Rather, it makes cost effective projects more accessible for end users who would consider making energy-related improvements to their facilities, while reducing the share of their cost that is paid by the utility or government. Vendors and contractors get excited about PAYS because it helps them sell more equipment jobs. Additional details about the PAYS approach and how it works are described in Appendix C.

PAYS could provide an avenue for San Francisco to administer energy efficiency programs in the City without access to PG&E's PGC funds. The structure of PAYS allows for any source of initial capital (typically utility funds, but can also be City bonds, private venture capital, bank loans, etc.) to cover the upfront cost of an energy measure. The recently approved proposition H bonds are a potential source of inexpensive capital in PAYS, but any entity with access to capital, including insurance companies, can fund PAYS activities.[81]

The customer pays back the cost of the efficiency measure through an additional line item on the monthly utility bill. The line item can theoretically be added to *any* utility bill within the City's jurisdiction, which in this case could include SFPUC's water bill, which reaches many customers that are not municipal energy customers. To implement PAYS, San Francisco would need to develop a source of initial capital and authorize an energy-efficiency service charge as an additional line item on the City's water bills for customers who participate in PAYS. As customers repay the cost of the efficiency investments, the replenished funds can be used for additional projects, reducing the need for additional capital as the program develops over time.

[81] One of the lessons learned regarding capital providers is that banks generally are more reluctant to participate because PAYS is not debt. Banks are generally skeptical of providing financing instruments other than debt.

PAYS can be used for any proven measure that is cost effective based on retail energy rates, although incentives can be used to make more measures, including renewable energy technology, cost effective. The PAYS structure is a good fit for several specific applications that offer high value in San Francisco. As noted above, PAYS could allow the City to help finance and implement efficiency programs for the residential and commercial sector. PAYS can also facilitate municipal projects by obviating the need for prior budget or voter approvals of new debt. PAYS does not create customer debt, as investments are repaid out of the savings from the efficient technology (see Appendix C).

In commercial rental properties, particularly small to medium commercial spaces where the business tenants' balance sheet and cash flow are constrained, PAYS can help leverage major energy improvements such as chiller and rooftop cooling system upgrades. Tenants would pay a portion of the capital cost via their energy bill according to the square footage rented or some other method. The investment does not impact the companies' balance sheets because it is not debt. Thus, the classic barrier of split incentives between owner and tenant can be overcome.

PAYS can be a tool for reaching small- to medium business tenants in the City, including SFO airport tenants who pay rent on City-owned property. In the private sector, hotels planning cosmetic improvements can also leverage PAYS for more attractive and efficient lighting or for increased thermal comfort and cost savings through a cooling system upgrade.

PAYS' ability to make efficiency improvements more accessible to the rental or other transient markets also means that residential rental properties—typically a hard-to-reach market—are suitable candidates for efficiency improvements. Low-income households could also be more easily targeted, because PAYS requires no upfront customer costs and incurs no debt. Even the retired population, who may hesitate to invest in energy improvements because of fixed incomes, would be better off with PAYS than with other financing mechanisms.

PAYS can also be applied to energy supply measures such as distributed generation and possibly solar PV. The same financing concepts apply as with DSM measures. In new construction, financing energy efficiency upgrades or DG would avoid adding the capital cost to the building's purchase and move it to the buyer's utility bill.

Comprehensive incentives and turnkey programs in multifamily and low-income housing

Multifamily housing represents 32 percent of total dwellings and 53 percent of total floor space in San Francisco. Many of these dwellings are rental properties that are difficult to reach with efficiency programs. Thus, multifamily housing, especially rental and low-income housing, is a key target for developing innovative energy efficiency programs in the City, and we have identified successful programs around the country targeting this sector of the market.

The Oregon Energy Trust provides turnkey energy efficiency assistance to multifamily housing customers (see Appendix C). It provides building audits and technical assistance, identifies financial incentives, and helps with contractor selection. While turnkey programs are currently available for small businesses in San Francisco, multifamily housing can also benefit from them.

Efficiency Vermont, the state's energy efficiency utility (see Appendix C), has become the recognized authority in its community on multifamily energy and energy efficiency. It sponsors comprehensive (whole building), fuel-blind efficiency incentive packages, and it developed an authoritative reference and teaching guide for architects and engineers on designing efficient multifamily buildings.

Implement load control or demand response

San Francisco's summer peak is driven by commercial sector lighting and cooling loads during the day, and its winter peak is driven by a combination of commercial and residential lighting and heating in the evening. Load control or demand response (DR) can be a useful tool for quickly reducing demand for short periods (up to a few hours) during those critical periods when electricity supply is short and/or expensive. When structured properly, demand response can also induce proactive efforts by customers to reduce energy use in the long term.

To date, DR has been tested mainly in the commercial sector. The State of California has endorsed demand response as a resource for taming volatile electricity markets. The State has conducted pilot DR programs, not only in the large commercial sector, but in the small commercial and residential sectors as well.

The San Francisco Community Coop for Bayview and Hunters Point is currently pursuing a pilot study to establish critical peak pricing for its residents. Based more on customer behavior than technology, this program combines aggressive customer education and information campaign with the CPP tariff to stimulate peak demand reductions.

During summer 2004, the three investor-owned utilities in California will be conducting a pilot program to test automated demand response system (ADRS) technology in residential buildings. The program will combine a critical peak pricing (CPP) tariff with automated control and two-way, real-time communication technology to allow small customers to limit their power demand during critical times.

Thus, progressive steps are already being taken in the City and the State to implement this effective DSM strategy. The lessons learned from these pilots can be used to help expand and develop demand response in San Francisco on a citywide basis. Although demand reductions in the City that are coincident with the PG&E system peak can contribute to relieving supply constraints and moderating power market prices, DR in San Francisco must be tailored to the City's unique demand profile. To contribute to relieving supply constraints based on the limited transmission capacity to import power, DR in the City must be able to limit commercial peak demand anytime between May and October, and possibly during winter evenings.

Commercial building operator training and certification

The Building Operator Certification (BOC) is offered by the Northwest Energy Efficiency Council (NEEC). BOC covers most aspects of energy efficiency in existing buildings and is offered in 17 states across the country. A total of 1460 operators have been certified since the program's inception in 1997, and building owners are beginning to look for BOC on resumes.

Operator training and BOC certification can create persistent energy savings in San Francisco's commercial sector by engendering long-term, ongoing savings through improved operation and maintenance techniques. Current state of staff expertise is highly varied, and BOC is a way of creating a common baseline of skills among operations and maintenance staff that includes awareness of efficiency opportunities and the ability to implement efficient practices. In particular, staff working on commercial and municipal buildings that do not have sophisticated whole-building controls would benefit.

Building energy code training for building inspectors

California's Title 24 residential building energy code is the most stringent in the country, and it has been recently updated for new and existing home construction. Unfortunately, the State's building energy code currently does not appear to be well enforced in San Francisco. Most building inspectors are trained to focus on fire code safety and construction code compliance. Energy code compliance is typically not emphasized in the licensing curriculum.

One method of addressing this barrier is to improve the training of building inspectors who are responsible for enforcing the building codes. While the SFE has conducted building inspector training on a case-by-case basis, San Francisco could consider a formal City-wide program for high volume, mass training of building inspectors on building energy codes. The training could be delivered as follow-up training after inspector certification or incorporated into the inspection licensing curriculum.

Building energy rating and certification

Building energy certification, such as the U.S. EPA's Energy Star label, or sliding-scale ratings, such as Home Energy Rating Systems (HERS) or LEED ratings, is an important part of an energy efficiency strategy. Certification or ratings provide standardized comparison between the energy consumption of one building against a reference building, making it easier to predict building energy performance and savings from efficiency improvement. Building certification and ratings can be used in conjunction with a variety of other energy efficiency programs. For example, they can be used in place of energy audits to qualify home owners for efficiency incentives such as rebates, low-interest financing for efficiency projects, or performance-based rebates. California has an existing home energy rating organization, CHEERs, which can be expanded in the City.

The U.S. EPA's Energy Star labeling for new construction qualifies new homes for the Energy Star label if they are at least 30 percent more efficient than homes built to the 1993 national Model Energy Code (MEC) or 15 percent more efficient than the State energy code (Title 24), whichever is more rigorous. The LEED rating system, described above, is another rating system that addresses building energy performance. LEED can be applied to existing or new commercial buildings and to new residential developments. Unlike HERS, energy efficiency is only one of several environmental factors that LEED considers in a building's overall rating. Thus a LEED Gold or Platinum rated building cannot be assumed to also be the most energy efficient.

Natural gas-specific efficiency programs

Most of the existing efficiency programs offered in California target electric energy efficiency, with portions of the program budget allocated for reducing natural gas use. Few efficiency programs are available that target natural gas specifically. While San Francisco needs to emphasize electric end-use efficiency and peak load management due to its supply constraints, several program ideas for natural gas-specific efficiency programs offered elsewhere in the State could be adapted to San Francisco.

Building weatherization programs that target building windows, envelope sealing and insulation also reduce gas space heating energy. They can also include measures such as HVAC duct sealing and increasing water heating tank and pipe insulation. Dedicated natural gas efficiency programs target end uses in the residential and commercial sector that directly consume natural gas, namely space heating, water heating, and cooking. Miscellaneous natural gas end uses include clothes drying, pool heating, fireplace and barbeque grills.

In 2001, Southern California Gas offered three programs targeted specifically at natural gas end-use efficiency in the commercial sector. The *Comprehensive Space Conditioning Efficiency Improvement Program* provided information, audits, and incentives for efficiency improvements in gas space heating systems. The *Advanced Water Heating Systems Program* provided information, audits and incentives for high-efficiency water heating equipment. The *Integrated Food Services Equipment Retrofit Program* provided information, audits and incentives to encourage small commercial cooking customers to make energy efficiency improvements.

Overcoming Barriers to Distributed Generation

Distributed (co-) generation is a key a component of the ERIS portfolios. The advantages of DG include the following:

- DG can provide modular increases in supply capacity to meet demand growth.
- Co-generation is clean and fuel efficient, especially with fuel cell technology.
- DG is the key in-City source to allow closure of all central, fossil generation.
- DG can potentially provide customer reliability and grid cost savings.

Despite these advantages, DG is only beginning to be developed in the City. There are several barriers to development of distributed generation sources and renewable energy, including the following:

- Lack of information and market familiarity by customers. DG sources are still relatively new and unfamiliar to most potential customers. Customers are building owners and facility managers, not experts in power technology. They consider the costs and potential benefits of DG to be uncertain and risky.
- High capital costs and difficulty to obtain financing. The costs of DG are concentrated in relatively high capital costs that can be difficult to finance. Power projects are complex and have high transaction costs. Because of the small scale of DG projects, these costs comprise a larger share of total project cost than for larger projects. These costs are fully at risk in the early stages of project development, so their contribution to financial risk is amplified.
- Power sales tariffs that do not reward grid support benefits of DG. Distributed generation can help distribution utilities defer investments in new capacity, provide voltage support and reactive power, and reduce losses. However, existing utility rate structures do not recognize these benefits.
- It is difficult to realize the potential reliability benefits of DG, which would require DG sources to switch from routine grid-parallel operation to operate in an "island" mode to serve loads during a grid outage. Islanding occurs when a fault in the grid separates a generating source from the rest of the system.[82] Present utility practice, however, discourages any sort of islanding.
- Difficult and expensive utility interconnection and system protection requirements. Utility standards for interconnection and protection equipment to allow on-grid operation of DG sources vary widely and can create potentially prohibitive costs. A utility that wants to prevent such sources from connecting can impose costly and time-consuming connection requirements.

The barriers related to customer information, risk perception and financing are beginning to be addressed effectively by the City, which is planning demonstration projects using fuel cells and

[82] An island is "any part of the distribution system, consisting of both generation and load, that operates without interconnection with the bulk power system." Dugan, R. and G. Ball. 1995. *Engineering Handbook for Dispersed Energy Systems on Utility Distribution Systems*. Final Report, Electric Power Research Institute. EPRI TR-105589.

other promising DG technologies, and by specialized DG project development firms, which are designing standard packages of technology and financial solutions to deliver to customers.

Barriers related to costs and power sales tariffs are mitigated to some degree by existing DG incentives. For example, PG&E offers the Self-Generation Incentive Program, which provides financial incentives for customer installation of clean, on-site distributed generation, up to 1.5 MW. Qualifying technologies currently include fuel cells, microturbines, low-emission internal combustion engines, and small gas turbines operating both on renewable and non-renewable fuel. A CEC program offers incentives for fuel cells using renewable fuels, inverters, photovoltaic modules, small wind turbines, system performance meters and solar thermal systems.

Realizing the potential for premium reliability and grid benefits remains elusive, as it depends on greater cooperation between distribution utilities and DG developers. Realizing reliability benefits also requires technical solutions to enable DG operation both in parallel and in an islanded mode, although such solutions exist.[83] The most urgent need at present, according to DG developers, is to streamline the slow and costly process for meeting City planning codes and utility interconnection and system protection requirements.

Discussions with DG developers active in San Francisco indicate that developers are managing the financial costs and risks of DG, and that the underlying economics of DG systems are attractive, as long as sufficient co-generated thermal energy can be utilized at the customer site. They observe that the City Planning Department's approval process is long, cumbersome, and provides no feedback on an applicant's design until all drawings and forms are submitted in full. Streamlining the application process and making it more interactive in the early stages would facilitate DG development.

Developers indicate that the cost and time required to meet utility interconnection and system protection requirements are high and can be prohibitive. For example, mandatory interconnection studies can be costly, even when the information is mostly routine and readily available. The process is especially complex in downtown San Francisco, where much of the DG potential is located (see the section on *Potential for Distributed Generation*), because the grid is a network system, rather than a simpler radial system.[84]

California's Rule 21 establishes a standard requirement for the interconnection application and approval process; however, it is designed for radial systems and does not specifically address network system connection. The position the PG&S has taken in its interpretation of Rule 21 for approving interconnection to the network system in downtown San Francisco makes it difficult for a DG developer to succeed.

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[83] For example, Chugach Electric Association installed and operates a fuel cell DG system on a post office in Anchorage, AK, which has the ability to produce 1 MW in grid-parallel operation and also to serve the post office load during a grid outage. Fast control and switching enable the system to transfer load and voltage reference from the grid to the on-site system and internal voltage reference, without having to trip. Steve Gilbert, Chugach Electric Association, personal communication, 16 December 2003.

[84] A radial system is fed by a single source, while a network system is fed by multiple sources with some degree of supply independence, which increases reliability but is also more complex to design and operate.

PG&E requires that DG developers pay the cost of protective relays and other equipment to sense fault currents and disconnect before equipment damage and other serious problems result. This is required even if the DG source produces less than the on-site load and has protection equipment to prevent back-feeding power out to the grid. PG&E is concerned that a DG source can cause frequent "nuisance" tripping of protective relays, which can shorten equipment life and increase the chance of failure. The developers acknowledge that system protection is necessary, but they are not convinced that PG&E's concerns represent problems that occur in practice with properly installed DG units.

In addition, PG&E requires that a DG source trip (shut down) if the load on the distribution transformer is less than 15% of its rating. This is a more stringent minimum-load criterion than that of Rule 21, which indicates a minimum import of 5% of the rated DG capacity. The PG&E criterion could require the minimum load to be 10-20 times as much as that defined by Rule 21. DG developers observe that this criterion is not met during many hours of routine operation in commercial buildings without DG, and that enforcing it would limit DG operation so much of the time that DG could not be economically viable.

Because DG is central to achieving the City's energy planning goals, the City government, specifically the SFPUC, has an interest in reducing these barriers to DG development, interconnection and operation, while ensuring that PG&E's needs for grid safety and stability are met or exceeded. At present, a somewhat adversarial relationship has developed between PG&E and the DG developers. Both sides are defending legitimate technical concerns and business interests, but they have reached an impasse. Thus, arbitration appears to be needed on behalf of the City and possibly citizen groups interested in achieving a diverse energy portfolio in San Francisco.

One step to facilitate the process would be to require utility action on connection requests within an appropriate time period, such as 4-6 weeks, minimize the need for detailed connection studies for small sources, and simplify the requirements for system protection and equipment, depending on the DG capacity and generator type. Such criteria have been put in place at the state level in Texas, for example, in order to help standardize and streamline the approval process beyond what can be accomplished by technical standards alone.

Another potential policy action related to DG would be to enable and encourage DG developers, building owners and utilities to complement energy efficiency improvements with DG sources, to help achieve the least-cost planning goal. There are two potential benefits: capturing the potential design synergies from integrating DG with building HVAC and control systems, and making better use of waste heat from DG in dedicated absorption chillers. At present, DG developers avoid demand-side efficiency measures because they could confuse the measurement of DG electric and thermal output, for which the building owner pays. However, this barrier could be reduced by a combined incentive program for DG and efficient heat-driven HVAC.

It is also worth considering the City's tax structure as an incentive mechanism. The installation of DG can cause an increase in the property value, which can increase property taxes. Foregoing this increase in taxes could be a way to remove a disincentive to the installation of DG systems.

Aggregation and/or Municipalization

To fulfill its energy planning goals and implement the ERIS portfolio approach, the City of San Francisco needs to become an energy portfolio manager on behalf of its citizens. At present, the City's influence on energy resource decisions is limited to the following functions:

- Operation of the Hetchy Hetchy hydro system (mostly governed by water supply needs)
- Serving the energy needs and implementing projects at municipal customers' facilities;
- Providing marketing and information for residential and commercial energy efficiency; programs (in collaboration with PG&E); and
- Setting local policies and funding incentives.

The present role served by the SFPUC and SFE does not entail enough authority to ensure that the necessary investments are made to implement the City's ERIS portfolio, unless there is very strong cooperation between the City, PG&E and private third-party developers and investors. As explained above under *Electricity Supply in San Francisco*, a kWh produced or saved by future City energy projects might be worth only the low price that the irrigation districts in Modesto and Turlock pay under their long-standing contracts with the City. This situation makes it difficult to justify investments in energy efficiency or supply, whether they are financed by the City itself or outside sources.

One way for the City to capture more of the value of future energy resource investments would be to acquire a larger customer base. Because the City already has the ability to produce enough power at Hetch Hetchy to serve its municipal loads, there is no ready buyer for incremental generation or even energy savings from DSM. With additional retail customers, however, the value of a kWh saved or produced would depend on the retail price at which the City could sell that energy, rather than the wholesale power market price or the lower irrigation district price.

Two direct mechanisms for the City to acquire additional customers are municipalization or community choice aggregation. A detailed analysis of these complex and controversial topics is beyond the scope of this report. However, we mention these issues because they are an important part of the context in which San Francisco's energy policy and planning will take place in the coming years.

Municipalization is the process of converting a private utility system to a public, municipal utility, or muni. Full municipalization typically involves the municipality acquiring ownership of the distribution system, by negotiated purchase or by condemnation proceedings, and assuming the role of distribution utility that PG&E performs in San Francisco today. This is often a long, expensive process that involves prolonged legal proceeding before the matter can be settled. San Francisco voters have decided several ballot initiatives on municipalization, and all have failed.

Another approach, call it "*muni lite*," involves taking over the procurement and portfolio management functions of the retail utility, while contracting with the incumbent distribution utility to continue operating the wires. In San Francisco, *muni lite* could be established through an amendment to the SFPUC's charter. This approach has also been subject to unsuccessful ballot initiatives in San Francisco, although the decisions have been closer than those for full municipalization.

Municipalization is usually opposed by the incumbent utility, because it threatens to erode the utility's assets and revenue base. However, it might be possible to design a *muni lite* structure that is acceptable to a distribution utility such as PG&E. We believe that it is worthwhile to continue exploring innovative designs for a utility structure until it is clear what solution is best for San Francisco, even if that solution turns out to be the *status quo*.

One proposed municipalization arrangement, which could be acceptable to the incumbent utility, would involve a "municipal power authority." This authority would buy the utility distribution system, and it would simultaneously hire the utility's unregulated subsidiary under a long-term service contract to operate and maintain the grid. The municipality would finance the acquisition through revenue bonds that would be repaid through utility bill revenues, without recourse to the general fund.[85]

The utility would maintain its revenue base, and the municipality would take over the procurement and/or development of energy resources. The advantage to customers would be to preserve the utility's expertise and scale in grid operation, while refinancing the distribution system, and financing new capacity investments, at the municipality's lower cost of capital. The authority would not answer to shareholders, but rather to the citizens. It could use the savings from its low-cost financial structure to pay a cost premium, if necessary to invest in aggressive DSM, DG and renewable energy to fulfill policy goals.

With either a *muni lite* structure or a municipal power authority, the municipality would assume the functions of energy resource procurement and development on behalf of customers. Community choice aggregation is another way that a municipality can assume this role, and it is specifically permitted under new California legislation, AB 117, which was passed in late 2002 and went into effect in January 2003.

AB 117 provides for a city or group of cities to combine the electric loads of willing customers for the purpose of reducing costs and protecting consumers. The incumbent utility would continue to deliver electricity through its distribution system. San Francisco's Local Agency Formulation Commission (LAFCo) is developing a plan for municipal aggregation, and the LAFCo has stated that it wants San Francisco to be the first California city to carry out community choice aggregation.[86]

Community choice aggregation would entail the City contracting with an energy service provider (ESP) through which to procure bulk power supplies. The City could also contract, either with the same ESP or other vendors, to provide DSM services, green energy from renewable sources, DG development, and other services. Provision of DSM, green energy and other services that would help fulfill City policy goals could be a condition of the City's contract with the ESP, or

[85] This proposal is explained in detail in Cichetti, C. and C. Long, 2003. "A Tarnished Golden State: Why California Needs a Public/Private Partnership for its Electricity Supply System," Pacific Economic Consulting.
[86] See R.W. Beck, "AB 117 Implementation Plan," report to SF LAFCo, August 2003.

they could be acquired separately, leaving the ESP to focus on low-cost power procurement. The latter arrangement would appear to be more workable.

Customers would automatically become City customers but would have the ability to opt out and elect service from PG&E or other competition if there is any. Community choice aggregation would give the City the ability to serve loads other than its own municipal loads. Thus, the energy saved or produced from City-owned resources could be sold to retail customers.

When San Francisco's contracts with the irrigation districts expire starting at the end of 2007, the City would be able to use the Hetch Hetchy hydro resources more actively, to firm intermittent renewable sources and to provide a buffer against the volatile power and natural gas markets. As the main retail energy supplier, the City would also be well positioned to offer energy efficiency programs to customers, and to encourage private investments in DG. It could work with PG&E to simplify interconnection procedures and to target DG development and DSM campaigns where they would help reduce grid costs.

Whether the formal structure involves full municipalization, *muni lite*, a municipal power authority, community choice aggregation, or continuation of the present structure, San Francisco can benefit from greater cooperation between the City government, PG&E, private businesses and citizen groups. Such cooperation could tap the technical expertise of PG&E, the financial creativity of the private sector, the City's access to inexpensive financing, and the community relationships of citizen groups. All of these actors need to participate, to benefit, and at times to compromise, for San Francisco to successfully implement the ERIS portfolios and meet the City's energy planning goals.