An Energy Resource Investment Strategy for the City of San Francisco

Scenario Analysis of Alternative Electric Resource Options

Prepared for the San Francisco Public Utilities Commission

by Rocky Mountain Institute
Principal Investigator: Joel N. Swisher, PhD., P.E.

January 2002

Table of Contents

Acknowledgements

This document was written by Joel Swisher, Karl Rábago and Andra Pligavko. We worked closely with the City of San Francisco Public Utility Commission (PUC) and Department of the Environment (DoE) in the course of the data collection, analysis, and reporting. We received valuable help and feedback from the following staff: Ed Smeloff, Bill Peden, Fred Schwartz, Sandra Rovetti, Marla Jurosek and Owen Brady at SFPUC, and Cal Broomhead, Danielle Dowers and Ann Kelly at the DoE. This work was funded by the San Francisco PUC.

Scenario Analysis of Alternative Electric Resource Options

Introduction

The future is by definition unknowable. The future success or failure of San Francisco's energy programs and initiatives will be determined by many forces and events. While an infinite number of possible futures lies before us, experience teaches us that the future will likely take the shape of one of a relatively few, identifiable scenarios. Today’s events and decisions will have largely predictable impacts on San Francisco's energy future. Scenario analysis is therefore a useful tool.

The benefit of scenario analysis is not in knowing the future, but in preparing for and shaping it. As distinguished economist and social scientist Kenneth Boulding once remarked:

"The evolutionary race goes to the adaptable, not to the well adapted,
to those who can learn, not to those who know."

Thus, the goal of a scenario process is learning, and addressing the questions:
- What are the major trends and driving forces at play?
- Which key actors and events are likely to have the greatest influence in the future?
- Which plans and actions are most likely to accomplish intended results?

This report describes a simplified scenario process in order to map out, in broad strokes, three alternative scenarios for San Francisco's energy future. The goal of this process, and of the more detailed analysis and planning process we hope to undertake in the near future, is to order our perceptions and priorities about the decisions that will determine the City’s energy future.

The transparency and quantitative detail of the process can help identify and de-personalize natural and inherent biases concerning visions of the future, and focus debate on critical issues. Hopefully, the scenarios can challenge elements of conventional wisdom and create common insight, common language and common culture in addressing San Francisco's vital energy future. Finally, the process of putting the future "on paper" can have the benefit of stimulating, fostering, and improving feedback from key decision-makers, stakeholders and the public.

In practice, scenarios resemble a set of stories built around carefully constructed plots. The stories express multiple perspectives on complex events and the scenarios give meaning to these events. Unlike traditional forecasting or market research, scenarios present alternative images instead of extrapolating current trends. Scenarios embrace qualitative perspectives and recognize the potential for sharp discontinuities that traditional planning and econometric models exclude. Creating scenarios requires decision-makers to question their broadest assumptions about how the world works, which can help them foresee consequences that might be missed or denied.

Ultimately, the result of scenario planning is not a more accurate picture of tomorrow but better thinking and an ongoing strategic conversation about the future.

The Process and Key Components of the Scenarios

The scenarios described below have been defined to be consistent with a common starting point—the present. These scenarios are each a distinct hypothesis or story about how the future may unfold, each based on internally consistent logic but somewhat different assumption. Each scenario also incorporates common trends and assumptions, and each addresses linkages and dynamics between driving forces and events. The process reveals and focuses on certain key uncertainties, creating an opportunity to shape the future by resolving the underlying questions.

The scenario development process involves blending factual, technical information with systemic observation to yield a clear understanding of the playing field on which future events will occur, the rules under which key actors will perform, and ultimately, a set of internally consistent scenario descriptions. Quantitative information about electricity demand, generation costs, market behavior, and transmission constraints are key input data. Qualitative inputs to the scenarios include on-going trends, driving forces, key actors, and major uncertainties.

Trends and Assumptions

We can already recognize trends that will likely shape the range of possible futures. For example, the electricity industry is increasingly composed of global companies with increasingly broad reach and scope. While the City of San Francisco can reasonably expect PG&E to be a critical part of its planning future, it will also be obtaining energy and services from a diverse range of providers with diverse business models. In addition, without aggressive measures to convert spontaneous, crisis-driven energy conservation into persistent energy efficiency, economic growth will continue to drive electricity demand growth.

There are also trends that are largely external to the City and influence the future in important ways. Technological improvements and siting difficulties contribute to a trend away from centralized industries in favor of smaller, distributed centers. Over time, smaller economic units have become increasingly viable, with important implications for the rate of customer demand growth and the type of electricity systems needed to serve them.

The future will be influenced by a number of conditions that we can recognize today as unlikely to change. Such predetermined elements are built into the assumptions behind each of our scenarios. For San Francisco, some of the key predetermined elements include:

- The City's commitment to close Hunter's Point Power Station,
- The need for focused local economic development,
- Limited tolerance of increased electric service bills,
- The dominance of residential and commercial demand for electric service and dominance of commercial sector in driving future demand growth,
- The growing demand for improved power quality and electric supply reliability, and
- The expectation of continuous environmental improvement.

Driving Forces

A number of existing social forces influence the range of possible futures and shape of the scenarios. Together, these driving forces comprise the "rules of the game," for choosing among competing policy and business options. The City of San Francisco is subject to many such driving forces, emanating from both within the City and outside, including:

- Public perceptions and public policy focus regarding the dangers and costs of air and water pollution, climate modification, and industrial safety,
- The changing economics of power generation and service provision,
- Evolution and development of energy and information technologies that could fundamentally alter delivery channels for energy services (e.g., fuel cells, microturbines, combined heat and power, real time pricing and control),
- Growing demand for demand-side energy services,
- State and region changes in electric industry regulatory systems, and
- Shifts in demand for electric services brought about by new technologies and informed, price-driven customer behavior.

Key Actors

The future is often made by the actions of key actors, who in turn often have the ability to change the "rules of the game." Understanding the motivations and desires of these actors, and the range of options available to them is another fundamental component of building likely scenarios. We can identify players who will have a key role in any scenario of San Francisco's energy future:

- San Francisco Board of Supervisors, the Mayor, and other City officials,
- California legislature, governor and regulators,
- Mirant and other independent power producers,
- Pacific Gas and Electric Company,
- Federal Bankruptcy Court,
- California Independent System Operator,
- Major energy consumers, and
- San Francisco Public Utilities Commission.

Major Uncertainties

It is just as important to elaborate what we don't know as what we do know. Present uncertainties can become critical factors and possibly reveal new alternatives that affect the future. These uncertainties include the number, size, behavior and responsibilities of industry players, the physical operating parameters of the electricity delivery system, weather patterns, fuel prices, environmental costs and constraints and others. In each scenarios, the relative influence of these uncertainties can vary, but for San Francisco, a few stand out most prominently:

- The pace and scope of economic recovery, including large potential new developments such as Mission Bay and Hunter’s Point shipyards,
- The features and success of any future electric utility municipalization initiative,

- The economic strength of independent power producers and energy traders,
- The future role and responsibilities of the Pacific Gas and Electric Company once it emerges from bankruptcy,
- The future structure of the California wholesale energy market,
- The role of the State of California through the California Power Authority or other institutions in procuring new energy resources,
- The success with which the City implements measures B and H and encourages distributed generation and demand-side investments,
- The condition of critical infrastructure components and risk of catastrophic failures, and
- The ability of PG&E or others to construct new major transmission projects in the Bay Area.

We have carefully considered all these key components to develop an internally consistent view of the broad environment in which San Francisco's energy future will unfold. From that perspective, we articulated three different scenarios for the City's electric energy future.

The Scenarios

The analysis yielded three broad scenarios for San Francisco's energy future. Essentially, these represent an extrapolation of the current situation and each of two deviations from that situation.

"Central Generation"

The first scenario (CG) assumes that Mirant will be successful in licensing, financing and constructing a large combined-cycle gas turbine (CCGT) power plant at the Potrero facility. The energy from this plant is either sold into a restructured California wholesale energy market or to PG&E under a long-term contract. To mitigate the exercise of market power the Independent System operator enters into a “reliability-must-run” or similar contract with Mirant, which covers some of the capital costs of the project and assures that the plant will run when needed for reliability.

Electric services under this scenario will be provided by the franchised private utility, Pacific Gas & Electric, or its successor corporation, following the PG&E bankruptcy proceedings. Concern over the general failure of electric utility restructuring in California lead to elimination of direct access to alternative energy suppliers and a reversion toward traditional cost-of-service regulation.

This scenario assumes the San Francisco PUC and Department of the Environment proceed with energy efficiency programs at a minimal level as concern about energy reliability diminishes. Minimal amounts of new renewable energy resources are developed with funding through

Proposition B. Instead, attention is redirected to other City issues such as the reliability of water supply and improvement of other local infrastructure.

Little if any third party development of distributed generation occurs because of the low short-term marginal costs of the large combined cycle power plant at Potrero. The closing of Hunter's Point occurs after the new capacity at Potrero comes on line.

Hetch Hetchy Water and Power continues to serve municipal electricity load in the City but does not expand its service to other retail customers. The City develops a new small combined-cycle power plant at San Francisco International Airport but does not otherwise significantly increase generation under the City’s control.

"More Imports"

The second scenario (MI) assumes that PG&E builds a new high-voltage transmission line from the Jefferson substation near Redwood City to the Martin substation near the San Mateo-San Francisco County line. This new transmission line allows San Francisco to increase its ability to import electricity by more than one-third. The import of power is managed by some level of coordination between the City and PG&E, principally through competitive processes.

Most of the incremental imported power comes form fossil fuel-fired power plants. The City develops a 50 MW wind power plant in the Bay Area in addition to a combined-cycle plant at SFO Airport.

Concerns about the future volatility of imported power costs provide public support for a moderate level of investments in energy efficiency, distributed generation and solar energy. These resources are funded through the Hetch Hetchy Power system and by City-directed investment of funds from the State-mandated public good charge. By 2012 San Francisco will have installed approximately 10 MW of solar generation. Minimal amounts of distributed generation is implemented by third-party developers because of concerns about financial risks and the lower short-term marginal costs of imported power.

Mirant refurbishes the existing power generation facilities at Potrero to comply with Clean Air Act requirements. The combination of these retrofits and the new transmission line allow for the closure of the Hunter’s Point power plant after the summer of 2005.

"Distributed Resources"

The third scenario (DR) assumes that neither the new central combined-cycle power plant at Potero nor the Jefferson-to-Martin transmission line is built by 2012. To assure reliability, the City of San Francisco takes on responsibility for developing new power resources. Two small combined-cycle power plants are built on City property by 2005 and a co-generation plant to meet downtown steam requirements is built by 2006. The existing power generation units at Potrero are refurbished and are available for reliability purposes.

Pressure for more local control of San Francisco's energy future leads to municipalization or some form of close collaboration between PG&E and the City in planning and procuring new energy resources. The City takes the lead in implementing a program to develop a more self-sufficient, clean, distributed energy infrastructure. Energy efficiency is aggressively pursued as the City expands its efforts to work with private residential and commercial customers. The combination of reduced energy load, the new smaller combined-cycle power plants and the co-generation facilities permits the shutdown of the Hunter's Point power plant.

The City aggressively implements measures B and H, resulting in the addition of 50 megawatts of solar generation by 2012. State and federal incentives encourage additional private sector financing of other sources of distributed generation.

Outside of San Francisco, the Hetch Hetchy system develops 150 megawatts of wind generation and 85 megawatts of new hydroelectric capacity, including pumped storage

Scenario Review and Comparison

Industry Structure

The environment in which each scenario develops is different.

Under the CG scenario, the central issue is the ability of Mirant to license, finance and construct a large combined-cycle power plant in San Francisco. Also at issue is the redesign of the wholesale power market in California that will prevent the exercise of market power by generators in transmission-constrained markets such as San Francisco.

Concern about the 2000-01 California market failure and the potential for future price volatility leads California regulators to rely principally on distribution utilities to manage energy resources through long-term contracts. The ISO manages much smaller day-ahead and real-time balancing markets. Electric service is based on cost-of-service revenue regulation, using cost averaging over time to mitigate the impact of supply price volatility.

This industry structure reinforces the dominat market position of the large, established players and existing technologies, principally central CCGT power plants.

Under the MI scenario, the central issue is the willingness and ability of PG&E to construct a new high-voltage transmission line to increase San Francisco's ability to import power. Also at issue is whether the Federal Energy Regulatory Commission (FERC) will succeed in creating a regional transmission organization (RTO) that facilitates an integrated electricity market in the Western U.S. Successful implementation of a competitive wholesale electricity market on a regional scale would allow San Francisco to import significantly more power at reasonable prices. However, failure of competitive markets to emerge could subject San Francisco to higher prices through the potential exercise of market power by power generators and energy traders.

The MI scenario assumes that PG&E emerges from bankruptcy with sufficient financial strength that it can implement planned transmission projects in the Bay Area and elsewhere in Northern California. The Hetch Hechy power system works within its jurisdictional boundaries to enhance energy security for the City. The central issue for the City is successful implementation of Propositions B and (to a lesser degree) H, as well as continued budgetary support for energy efficiency and infrastructure refurbishment.

Finally, under the DR scenario, the central issue is whether the public and the political leadership of San Francisco support increasing the City's responsibility and authority for developing and delivering energy services. Increased local control over the City's energy future creates a broader range of local solutions. At issue will be the City's ability to finance both the new combined-cycle plants needed for reliability as well as multiple solar power and distributed generation facilities. Financing will depend on whether the City has responsibility for providing electric service directly to retail customers in San Francisco. Also at issue will be the City's ability to access funds from the State-mandated public good charge for energy efficiency measures and its ability to develop and carry out broad-based energy efficiency programs. The success of these efforts will depend, in part, on the ability of the City to establish strong partnerships with commercial customers that constitute a large portion of San Francisco's energy load.

Policy, Regulation and Legislation

Policy decisions will exert a strong influence on the results that emerge in each of the scenarios. These decisions, in turn, depend on the policy drivers that are most prominent. Different sets of policy drivers achieve prominence in each scenario.

Under the CG scenario, the strongest policy drivers are the economic climate and the jurisdictional roles of the Federal and state governments in regulating the electricity industry. The collapse of Enron has weakened investor confidence in merchant power plant developers. This has led to the cancellation of numerous power plant projects and made it more difficult to finance projects that are still slated for development. The key to the potential development of the proposed new Potrero unit 7 is the ability of Mirant to convince investors that it will be able to recover its capital costs plus a sufficient rate of return. This cost recovery may depend on Mirant's ability to negotiate an attractive "reliability-must-run" contract with the ISO or, alternatively, a long-term contract with PG&E that is accepted by the California PUC. The terms of such a contract with PG&E may be affected by the PG&E bankruptcy case.

Assuming that PG&E takes on responsibility for procuring new energy resources, the California legislature will determine the level of support for developing energy efficiency, renewable sources and distributed generation through the franchised utility. The City government plays a relatively minor role in new in-City resource development through local ordinances and through the SFPUC.

Under the MI scenario, the key policy drivers are the willingness of the CPUC to rate-base the cost of constructing new transmission facilities, and the potential local environmental opposition to transmission facilities and transmission congestion management rules to be developed by the ISO. For new transmission projects to be rate-based, electric utilities must obtain a certificate of public convenience and necessity from the CPUC. Granting of such a certificate may depend on the environmental impacts of the facility, as well as alternative means of meeting electric reliability. In addition, the congestion management rules may determine how the costs of the new project are allocated among Northern California ratepayers. Currently the costs of transmission are averaged across the entire California grid. Under some policy proposals, the costs could be assigned to specific regions or zones, and this approach could raise the cost of transmission projects to San Francisco ratepayers.

For the development of renewable and energy efficiency resources, an important driver will be the public and political commitment to use the City's financial resources to increase reliance on energy efficiency, renewables and distributed resources to provide energy services for City functions. The CPUC also has an important role in determining what entities will administer energy efficiency programs paid for by a public goods charge on the delivery of electricity to PG&E customers.

Under the DR scenario, the key policy driver will be the willingness of local elected officials to assert more local control over both City and private energy services. Current state regulations lock customers into their current utility franchise and prohibit those customers from obtaining electric service from alternate providers. For the city to assume increased responsibility for resource procurement, a change in state laws or regulations would be required. Alternatively, the City could assume ownership of the transmission and distribution facilities in San Francisco and provide electric service as a municipal utility. In any case, as the City assumes greater control of energy services regulation within its jurisdictional boundaries, the City government becomes the key source of energy policy, regulation, and local legislation. State regulatory and legislative actions will remain important in creating a favorable environment for the development of distributed and renewable energy sources.

Markets

The most distinct differences between the scenarios emerge in the context of the market structures at work under each.

In the CG scenario, investors in new conventional power plants will require these investments to be secured by long-term contracts. The recent reduction in the creditworthiness of merchant power plant developers like Calpine, Mirant, Dynergy and Reliant has called into question the commoditization of wholesale supply markets and thereby limited investments in new merchant power plants. Investments in renewable energy resources will be determined by regulatory mandates such as a renewable portfolio standard. Absent a regulatory mandate for utilities to procure energy efficiency resources, investment horizons for commercial and residential customers will be relatively short.

The customer price for delivered energy will still largely not reflect externalized costs, which will continue to be paid via health and environmental damage across the region. Above-market costs for investments in reliability, spinning reserve, and transmission capacity, as well as costs caused by wholesale price volatility, are transferred to statewide charges or to the taxpayers. Transmission open access regimes will remain in place, but the uncertainties that dominated in 2001 may be mitigated by re-regulation and stronger reliability-related requirements. Retail residential and commercial customers will see relatively few energy service choices. Exit fees designed to protect cost recovery for utility investments (and the requirements of the bankruptcy case's final decisions) will serve as a barrier to self-generation options.

The preference for large generation solutions and the difficulty of siting plants near or in urban centers will lead to concentration of generation resources. However, regulatory mechanisms will be reintroduced to keep customers from seeing direct effects of the exercise of market power. Resource portfolio decisions will be shaped and determined largely by developers of large central plants, and by regulators who approve the costs and place them into rates.

The power market will resemble a traditional rate regulation and franchise arrangement, except for non-utility ownership of generation assets. The need to protect revenue streams for these investments, and for any bankruptcy settlement or ruling, will also maintain pressure against easy interconnection of distributed generation. The potential for the development of distributed energy resources will depend on the nature and extent of statewide incentive programs and rebates. The role of the City of San Francisco will be limited to municipal facilities and loads.

Under the MI scenario, the City's efforts to develop renewable energy sources under Propositions B and H will be strengthened by participation in statewide programs designed for municipal utilities, including the Public Partnership for Renewable Energy, rebate and buy-down programs, and energy research projects. Retail customer demand for energy efficiency and renewable energy services, however, will remain largely as it has under the current regime. Initially, choice for these customers will be dictated by the terms of statewide incentive programs relating to renewables, distributed generation and energy efficiency services. Success of economic development in the energy services sectors can, over time, lead to enhanced availability of such service options to these and other customers.

Investment decisions for the PG&E system will continue to be driven by regulation, Wall Street and the bankruptcy court. However, the City government and the public will be the main decision-makers regarding City energy programs, along with private financial sources involved in municipal finance markets. Wholesale market behavior in the region and throughout the state will continue to set the benchmark for commodity prices, and guide rate-setting policies for municipal customers.

Under the DR scenario, markets will be mixed and will entail longer planning horizons for energy efficiency, renewable energy and distributed generation investments. Analysis of investment options will involve explicit consideration of a range of environmental and social concerns and be more customer-focused. The City will face strong pressure to resist direct access choice by customers, either by out-competing alternative suppliers or establishing customer retention policies.

The City utility will need to accept and manage a broader range of technological and economic risk. Local market power can be significantly mitigated by the reliance on more, smaller generators with diverse ownership. However, sophisticated communications and control systems will be required to meet the demand for reliable, high quality power services. This requirement could be met either through municipalization or through close coordination with PG&E.

Under the DR scenario, the City will need to develop multifaceted relationship with suppliers of energy efficiency, renewable energy and distributed generation technologies and services. These relationships could support the emergence of new, self-sustaining market segments in clean energy services, which could also influence the choices offered to utility customers in California.

Technology

Technology plays a crucial role in shaping each of the scenarios.

The focus in the CG scenario is on established, large-scale energy supply technologies. The dominant technology choice in San Francisco is the expansion of the Potrero generating facility. The focus on a large combined-cycle power plant as the principal solution to reliability results in evaluating other incremental technologies in a linear fashion. That is, future demand is forecasted; then generation technologies are selected according to their initial capital costs. Transmission and distribution options are evaluated separately, as are energy efficiency and load management solutions.

In the CG scenario, energy efficiency, renewable sources and distributed generation are introduced primarily through pilot projects or as a result of regulatory mandates. As a result, the adoption of new technologies in San Francisco is slower in this scenario than in others. The consequences of technology choices, such as pollution, local neighborhood impacts, economic development, and others, are addressed through regulatory public participation processes, and are accounted for or mitigated in the siting and construction requirements that emanate from regulatory decision-making.

In the MI scenario, the choice to rely on imports to meet much of San Francisco’s energy requirements pushes decisions about the type of power generation technologies onto other communities. To the extent that new resources are procured by PG&E, technology choices could be guided by state-level policies and incentives. The development of solar and other renewable energy projects under Propositions B and H stimulates interest by other cities and counties to create markets for clean, distributed energy technology. By enlarging markets for these technologies, the City accelerates the pace of their development. Favorable interest rates for municipal investments decrease first-cost barriers associated with adoption of new technologies. Local concerns also exert a greater influence over technology choices, including those related to local employment, localized pollution, and other factors.

In the DR scenario, no single technology dominates. Instead, various energy efficiency and peak load management technologies gain importance, and a wider variety of generation sources – natural gas-fired co-generation, microturbines, fuel cells, solar photovoltaics, etc. – are deployed in numerous locations. This technological and geographic diversity is enabled by the smaller size and minimal environmental impact of the selected technologies. Thus, technology decisions are made at finer degrees of resolution. Also, the proximity of energy technologies to the customer means that public perception and preference plays a greater role in shaping the technology portfolio.

When more people live near a power generator — be it solar, fuel cell or microturbine — issues related to design and integration into the community become more important. Thus, technology selections are likely to be smaller and more modular in nature, cleaner in performance and incorporated into building design and neighborhood planning. The objective of capturing cost-effective renewable resources also stimulates development of larger-scale options such as wind farms in Alameda County and pumped storage hydro associated with the Hetch Hechy system.

Uncertainties and Risks

Each scenario is vulnerable to major uncertainties and disruptions.

Under the CG scenario, there are two major risks facing the City. The first risk is that development of the new Potrero unit 7 is significantly delayed or cancelled because of investor concerns about the California electricity market. Recent plant cancellations by Calpine and Mirant increase the salience of this risk. The second risk is that the owner of the Potrero power plants is able to exercise market power, creating more volatile and higher electricity prices for San Francisco. Mitigation of this market power is primarily the responsibility of the Federal government and the ISO. The City has relatively weak tools to mitigate market power, such as developing alternative supplies or inducing energy efficiency, peak load reduction and distributed generation. The City could face difficulty in bearing the economic burdens of large and potentially over-built supply infrastructure, especially under zonal pricing or rate allocation schemes. Finally, the City’s dependence on relatively few, concentrated generation sources introduces a degree of vulnerability to catastrophic failure associated with natural disasters, sabotage or other forces.

The major risks under the MI scenario are threefold. The first is the risk that opposition to construction of the new transmission line in San Mateo County results in its delay. This delay would increase the length of time that the city must rely on the aging Hunter’s Point Power plant. Since PG&E has indicated that it does not intend to retrofit this plant’s emission control system, the City would face the choice of higher local air pollution or decreased reliability. The second risk is that changes in the rules for allocating transmission costs by the ISO or FERC could increase the price of electricity to San Francisco. The third risk is increased vulnerability to catastrophic failure, because the new transmission line feeds into the same substation at the San Francisco-San Mateo County line as do all other transmission lines into San Francisco.

The biggest risk under the DR scenario is unrealized potential. Effective implementation of the large-scale commitment to energy efficiency measures, solar power projects and distributed generation will require an increased degree of local control over the electric system in San Francisco. Possible PG&E resistance to cooperating in the interconnection of many new generating facilities to the local transmission and distribution system could be a formidable obstacle to realizing this scenario. In addition, PG&E's concerns about lost distribution revenue may make them reluctant to jointly plan with the City for the implementation of distributed resources. Another obstacle in implementing the DG scenario is increasing the capabilities of City government to plan and implement these projects in a timely and efficient manner. The success in implementing this scenario will depend on the degree of broad political consensus to deploy these distributed energy technologies in San Francisco.

Summary of Scenario Descriptions

The matrix in Table 1 summarizes the key attributes of the scenarios.

Table 1. Scenario descriptions

SF Energy Plan Scenario Descriptions

	"Central Generation"	"More Imports"	"Distributed Resources"
KEY FEATURES	A large combined-cycle power plant located at the existing Potrero power plant is the principal new source of electricity for San Francisco over the next 10 years. The owner, Mirant, has significant market power during many hours of the year. Market power is mitigated by some sort of power purchase agreement with Mirant and PG&E, the City or the ISO. Surplus power available from this plant dampens efforts to implement energy efficiency measures, DG and renewable energy technologies. Support for new transmission into San Francisco is weakened.	PG&E builds a new transmission line from Redwood City into San Francisco (Jefferson to Martin) that permits the import of increased quantities of power principally from fossil fuel power plants located in Northern California. Some competition among energy suppliers emerges to control the cost of electricity. The City uses Prop B funding to develop some renewable energy sources, while expanding efficiency programs. Mirant completes air quality retrofits for the existing thermal power plant at Potrero which remains the principal in-city source of generation.	Concern about the risks of deferral or cancellation of the proposed new Potrero power plant and the Redwood City to San Francisco transmission line leads the City to take responsibility for developing new in-city energy resources. The SFPUC develops several new, smaller cogeneration or combined-cycle power plants and launches an aggressive program of efficiency and renewable sources, SFPUC increases the purchase of wind generation from outside the City and completes major upgrades to the Hetch Hetchy hydro system.
PLAYING FIELD	Concerns about electricity reliability and market power of merchant power plant owners lead to a re-regulated electric sector with increased resource procurement responsibilities for investor-owned utilities, the state or the ISO. Aversion to higher short-term costs minimizes investments in energy efficiency and renewables.	PG&E successfully convinces the ISO and CPUC to allow it to construct and rate-base a new high voltage transmission line into San Francisco. PG&E emerges from bankruptcy and takes on procurement of new resources through competitive processes. The SFPUC continues to serve city customers and develops new energy efficiency and renewable resources to meet load growth.	City establishes authority to serve additional retail customers in San Francisco and takes the lead role in procuring new energy resources. San Francisco's environmental values drive significant investments in energy efficiency, DG and renewable energy resources. Planning for new energy resources is done in a comprehensive manner.
KEY ACTORS	Mirant, CAISO, FERC, CPUC; State Legislature	PG&E; Bankruptcy Court; ISO, CPUC: SFPUC	City of SF; SFPUC; State Legislature; PG&E; energy users; renewable energy developers
MAJOR UNCERTAINTIES	Creditworthiness of merchant power plant owners; ability of ISO and FERC to effectively mitigate market power. Role of state in planning and procuring energy resources.	Emergence of PG&E from bankruptcy and its future role in resource procurement. Local opposition to the construction of a new high voltage transmission line.	Ability of SFPUC to develop new energy resources for San Francisco. Cooperation of PG&E and SFPUC in carrying out comprehensive resource planning.
MARKET	Uncertainty about investment	Driven by bankruptcy decisions	Increased role for City triggers

ENVIRONMENT	criteria for new generation and energy efficiency. Near-term surpluses keep wholesale prices down. Non-market costs not internalized.	and ISO market re-design. Investment decisions in new transmission driven by government rules on cost recovery. SFPUC takes integrated approach to resource procurement for municipal customers.	longer planning horizons for energy efficiency, renewables, and distributed generation. Investments are driven by use of tax-exempt municipal financing. Environmental costs are internalized.
MAIN STRUCTURAL ISSUE	Redesign of California market by FERC, State Legislature and CPUC.	Role of PG&E following bankruptcy. City implementation of Propositions B & H.	Increased role for SFPUC in resource planning and procurement.
BIGGEST RISKS	Potrero plant is delayed or cancelled because of Mirant credit problems and/or market uncertainties. City remains dependent on Hunters Point power plants for reliability. If new power plant is built, Mirant is able to exercise market power in San Francisco, causing retail rates to increase.	Environmental opposition to the new transmission line causes significant delays or cancellation. City remains dependent on Hunters Point power plants for reliability. Mirant fails to upgrade existing Potero units resulting in significant limits on their hours of operation, thereby increasing the probability of power outages.	City is incapable of developing new power resources because of political opposition or inability to finance. City remains dependent on Hunters Point power plant. SFPUC and PG&E are unable to jointly plan implementation of distributed resources leading to a protracted political stalemate on municipalization.
REGULATORY ROLE	FERC and CPUC argue over responsibility for wholesale market design. FERC and ISO provide financial assurance that allows new Potrero plant to be built.	CPUC approves rate-basing of new PG&E transmission line and assigns long-term resource procurement responsibilities to PG&E following bankruptcy.	City undertakes resource procurement responsibility for SF retail customers and develops cost-of-service rate structure.
STATE LEGISLATIVE ROLE	Acquiesces to predominant FERC role in wholesale market design for California.	Supports CPUC re-regulation of investor-owned utilities while supporting local initiatives for renewable sources and energy efficiency.	Provides for increased role for municipal governments in resource planning and procurement. Supports commercialization of emerging clean distributed generation technologies.
FINANCING SOURCES	Most financing is supported through bilateral power purchase contracts with power plant developers. Some state investment to provide adequate reserve margins.	Most financing of new facilities is supported by CPUC regulatory orders that provide for cost recovery of new energy projects by investor-owned utilities. City of SF finances municipal programs from Prop B bonds.	New energy resources are primarily financed with municipal revenue bonds. City aggressively implements Prop B and Prop H bonds.
DEMAND FOR DISTRIBUTED RESOURCES	In proportion to statewide incentive programs.	Driven by implementation of Props B and H in coordination with statewide incentive programs.	Diverse, varied demand is partly aggregated by the City utility, increasing buying power and decreasing costs.
TECHNOLOGY DRIVERS	Preferred technologies are large, proven, and have low initial capital costs.	Technology choice is largely driven by regional markets with preference for proven, low first-cost options. Some local choices are driven by implementation of Props B and H.	City utility choices driven by site-ability, environmental performance, reliability effect, and local production opportunities.

Other Scenarios

The three scenarios analyzed in this document represent three specific points of departure along a wide spectrum of possibilities. Many other combinations of assumptions about policies, markets and technologies could be used to construct different scenarios. Given the limited time available to produce this document, we chose these three to illustrate the key issues.

In the course of a more in-depth analysis, we hope to explore a wider range of scenarios, including some hybrids of the three presented here. For example, one interesting variation would be an aggressive efficiency and distributed energy scenario, similar to DR, but with the additional transmission capacity assumed in the MI scenario.

This suggestion and other alternative scenarios can and should be explored in depth, in order to design the best possible Energy Resource Investment Strategy for San Francisco. None of the three scenarios presented here are necessarily optimal, or the best possible compromise among the competing criteria considered. Rather, they are intended to illustrate the possibilities available and the trade-offs involved in implementing different options.

Design of the Scenario Analysis for San Francisco

Based on the qualitative scenario descriptions explained above, we constructed a quantitative picture of each of the scenarios. Again, these future scenarios are not predictions of the future. Rather, they are exploratory tools that allow us to ask a set of hypothetical "what-if" questions. The answers come in the form of a set of internally consistent views of possible future energy systems. By internally consistent, we mean that the results must conform to the same logical consistency, i.e., that energy supply equals demand in each case, and assumptions do not contradict each other in any noticeable way.

The transparency and quantitative detail of the process can help clarify differing visions of the future, challenge decision makers to foresee consequences that might be missed or denied, and focus debate on critical issues. Hopefully, the scenarios can provide a degree of common insight and common language in addressing San Francisco's energy future. The process itself can have the benefit of stimulating feedback from key decision makers, stakeholders and the public. The intended result of scenario analysis is better thinking and strategic conversation about the future.

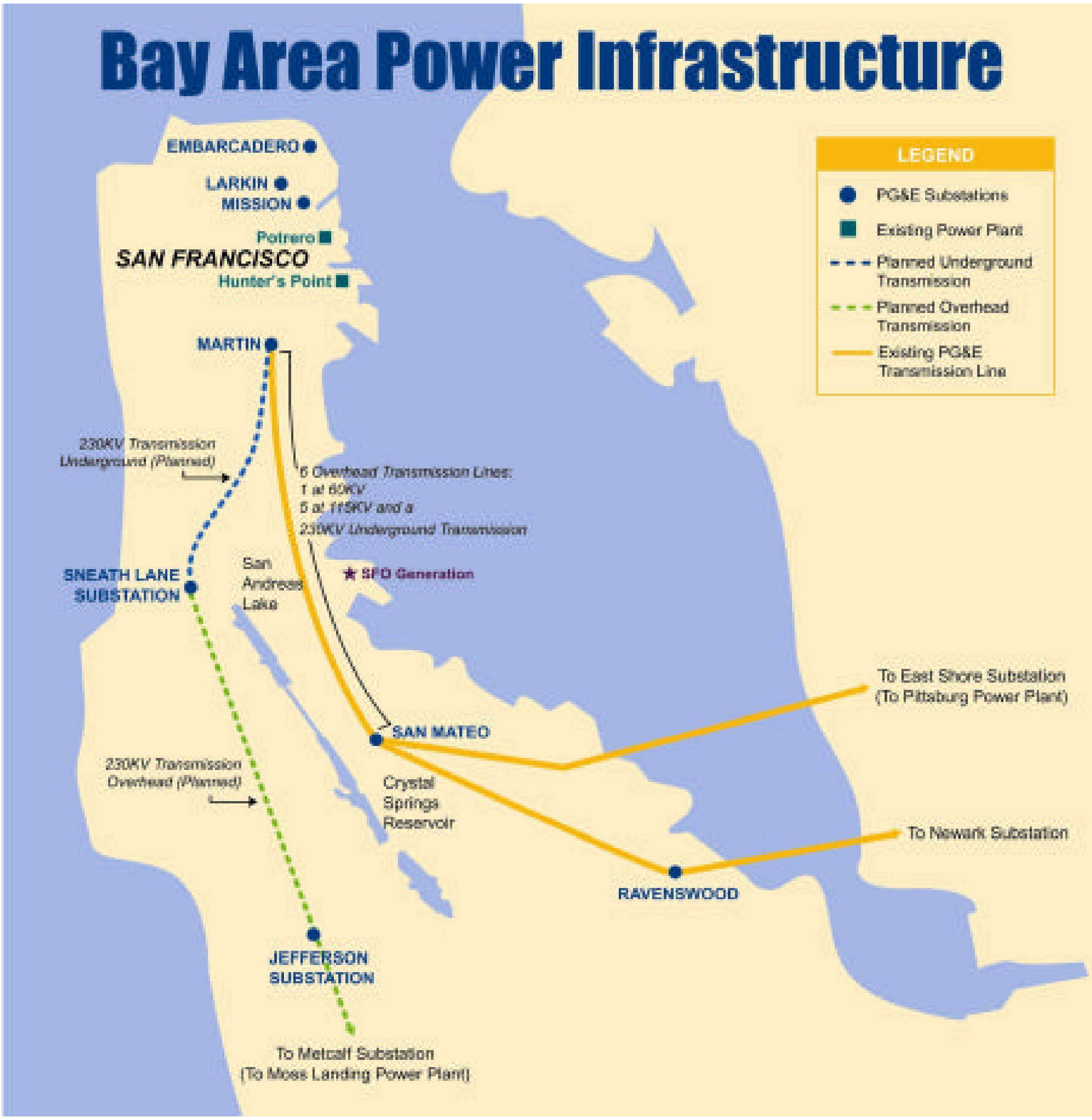

Figure 1. Location of major electricity supply facilities serving San Francisco

System Boundaries

For the City and County of San Francisco, political, geographic and electric system boundaries are a key component of the scenarios (see Figure 1).

- Political boundaries can be perceived in widening circles, these include such communities of interest as the neighborhoods near the Hunter's Point Power Station and Potrero Power Station, 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, 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 Martin substation with its supply source in San Mateo. The proposed Jefferson-to-Martin line would provide another, partly separate source. 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.

These boundaries are critical to the evaluation of opportunities, for example, to generate and transmit power, to site facilities, and to maintain system reliability. For example, while wind energy can provide a cost-effective, environmentally benign energy resource, siting, performance and cost issues require that such a resource be located outside the City of San Francisco, most likely in Alameda County. This energy must be transmitted to the City via the PG&E grid. No likely scenario contemplates the siting of wind farms within the City.

Finally, in addition to the electrical, geographic and jurisdictional boundaries, there are the boundaries between the key industry players. The residents and businesses of San Francisco obtain electric service from PG&E, and the San Francisco Public Utilities Commission provides service to municipal customers. Under current conditions, the lines between these entities are both clear and significant for planning. As a result of restructuring in California, some generation resources are owned by utilities (mostly large hydro and nuclear), and some are not (mostly thermal and small renewable).

Role of Electricity Resources in the Scenarios

Because the electrical boundaries are rather complex, the scenario analysis must account for certain activities outside the political boundaries of the City and County of San Francisco. As noted above, 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 area of Peninsula is relevant because the San Mateo substation is the sole source of transmission capacity to areas north of this substation, 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 2):

- 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 2. Breakdown of the role of each type of electricity resource in the scenarios

Resources that meet reliability needs only	Resources that meet reliability needs and supply energy	Resources that supply energy only
▪ Transmission capacity into Martin substation	▪ Hunter's Point Generation ▪ Potrero Generation ▪ New City Generation ▪ Distributed Generation ▪ Solar in CCSF ▪ Efficiency/DSM in CCSF ▪ Biomass/biogas in CCSF ▪ Peninsula Generation ▪ Solar on Peninsula ▪ Peninsula Efficiency/DSM	▪ Hetch Hechy Hydro ▪ Wind in Alameda County ▪ Purchased Imports

Methodology

The scenario analysis is based on a simplified bottom-up approach.[1] 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 an estimate 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:

[1] 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.

- 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
- Design of an integrated strategy to minimize economic costs and environmental impacts
- Implementation of the selected strategy

The resources options in each scenario must meet both the total energy demand (in MWh) and the maximum peak demand (in MW). Peak demand can be met either by electricity supply resources, via the generation and T&D systems, 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.

Note that this document presents a preliminary version of a full ERIS for San Francisco. The limited time and resources available have not allowed use to research and evaluate the electric supply and demand-side options fully, nor have we examined a full range of plausible scenarios and sensitivity cases. Thus, the objective here is not to select and design a single outcome for final implementation, but rather to identify a range of options for more detailed exploration, based on input from a range of stakeholders and the general public.

Demand for Electricity Services in the Scenarios

The *baseline demand scenario* is the starting point in the analysis of supply resources and energy-efficiency improvements. For the purposes of this analysis, we adopt the most recent statewide demand forecast by the California Energy Commission, which includes a peak demand forecast for San Francisco.[2] We take the CEC's projection for 2012 (1169 MW peak), and interpolate a smooth growth function from 2000 (945 MW peak), which gives an annual growth rate of 1.8%.

We use the 2000 electricity consumption value of 5360 GWh, which gives an average load factor of 64.75%.[3] This load factor is used to project consumption growth through 2012, when the total electricity use reaches 6630 GWh. The same growth profiles are used to project Peninsula demand from 2000 to 2012. Load growth on the Peninsula reduces the effective transmission capacity to import power into the City. These and other general assumptions are listed in Table 3.

Note that we use the demand for the year 2000 as the base from which to extrapolate, rather than 2001. The demand in 2001 was strongly influenced by emergency demand reductions, much of which resulted from behavioral changes that can be expected to disappear after the crisis ends. Therefore, we treat this year’s demand as anomalous and project future demand from the level observed in 2000, using a smooth growth function as described above.

---

[2] California Energy Commission, 2001. “California Energy Demand 2002-2012 Forecast,” Table E-2, http://www.energy.ca.gov/energyoutlook/documents.

[3] Load factor is the ratio of average to peak demand.

Table 3. General Assumptions

Gas Cost	3 $/MMBtu
Gas Cost Escalation Rate	2 %/year (real)
Discount Rate	4.5 %/year (real)
Load Factor	64.75 %
Annual Rate of Demand Growth	1.80 %
Peak Availability of Wind	30 %
Peak Availability of Solar	75 %
Peak Coincident DSM Savings	80 %

Assumptions on Electricity Supply Resources in San Francisco

Each scenario includes a different set of generation resources in the City. The existing resources include a total of 370 MW of gas-fired steam turbines and 208 MW of oil-fired combustion-turbine (CT) peaking plants. As shown in Table 4, these plants are located at Hunter's Point (unit 4: 163 MW steam, unit 1: 52 MW CT) and Potrero (unit 3: 207 MW steam, units 4-6: 156 MW CT).

Table 4. Existing major generation source in San Francisco

Generator Plant	Capacity	Type	Fuel	Status
Potrero Station				
Unit 3	207 MW	Steam	Natural gas	Operating
Unit 4	52 MW	CT	Oil	Operating
Unit 5	52 MW	CT	Oil	Operating
Unit 6	52 MW	CT	Oil	Operating
Unit 7	*540 MW*	*CCGT*	*Natural gas*	*Planned to open 2005?*
Hunters Point Station				
Unit 1	52 MW	CT	Oil	Operating until 2005?
Unit 2		Steam	Natural gas	Closed
Unit 3		Steam	Natural gas	Closed
Unit 4	163 MW	Steam	Natural gas	Operating until 2005?

All of these units are old and high in emissions. The City and PG&E have agreed to close Hunter's 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. In addition, the remaining units at the Potrero plant would need to be retrofitted with more advanced emission control equipment to improve environmental quality in the southeast part of the City. Assumptions on the resources used in the scenarios are summarized in Table 5.

Table 5. Assumptions on Costs,[4] Efficiency and Capacity Factor[5] for Electric Resources

	Capital Costs ($/kW)	Heat Rate (MMBtu / MWh)	Non-Fuel Energy Cost ($/MWh)	Capacity Factor
Hunter's Point	N/a	11	20	40%[1]
Potrero – Unit #3 without retrofit	N/a	11	20	40%[1]
Potrero – Unit #3 with retrofit	242	10	15	10-40%
Potrero – Unit #7 new CCGT	833	7	8	63%[2]
New City Generation	850	8	10	75%
Energy Efficiency / Demand Side Management	100-1400[3]	0	0	65%
Distributed Generation	1500[4]	10	3	68%
DG – Fuel Cells	4000[4]	8	3	68%
Solar	4500[5]	0	0	19%
Biomass	1500	10	10	80%
Wind	1000[6]	0	11	35%
Hetch Hetchy Hydro	1000[7]	0	35	40-60%
Purchased Imports	N/a	N/a	32	20-50%

Notes: 1. Capacity factor is based on monthly metered generation during 4/98-3/01. 2. Capacity factor includes unit 7 at 80% and peaking CTs at 3%. 3. DSM costs depend on the amount implemented, see footnote 8. 4. DG capital costs decline at 3%/year for fuel cells and 1%/year for other technologies 5. PV capital costs decline at 3%/year. 6. Wind capital costs decline at 1%/year. 7. Cost of retrofit upgrades only.

In the Central Generation scenario, Mirant builds Potrero unit 7, a 540 MW gas-fired CCGT, in 2005. The addition of unit 7 allows the closure of unit 3.[6] The CTs continue to provide 156 MW

[4] Non-fuel operating costs include operation and maintenance, transmission cost for resources outside the City, and a $12/MWh credit for co-generated thermal energy from DG sources.
[5] Capacity factor is ratio of the average power output to the rated capacity.

of peaking capacity. Other in-City resources include a 2-MW biogas-fired plant that is already planned and a small amount (500 kW/year) of new solar photovoltaic (PV) development.

In the More Imports scenario, the Hunters Point generation plant is closed when the new Jefferson-Martin transmission line increases the total power import capacity into the City. However, this new line is not expected to be in place until 2006. The closure of Hunter's Point is accompanied (or preceded) by 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. In addition, smaller distributed generation (DG) and solar PV each add one MW per year of capacity.

In the Distributed Resources scenario, the Hunters Point generation plant is closed in 2005, when two City-owned CCGT units, with a total capacity of 114 MW are put in service along with load reduction of 23 megawatts form energy efficiency programs and the installation of 35 MW of distributed generation. These units are needed to maintain adequate reliability without either the Hunter's Point plant or the Jefferson-Martin transmission line. The installation of these units is followed in 2006 by a new 50-MW co-generation facility in downtown San Francisco.

The remaining steam-turbine power plant at Potrero (unit 3) is upgraded with emission controls and along with the three CTs at Potrero are used primarily for system reliability and for peaking capacity. In addition, smaller distributed generation (DG) capacity, initially using microturbines and later using fuel cells, adds 100 MW of capacity in the City by 2012. Finally, 50 MW of solar PV capacity is installed by 2012.[7]

Assumptions on Electricity Efficiency and Demand-Side Management

The scenarios represent a range of increasingly ambitious energy efficiency and other demand-side management (DSM) programs. We assume that 80% of the demand savings in all scenarios are peak coincident. In other words, every 100 kW of load reductions reduce the local area peak demand by 80 kW. We also assume that the load factor for energy savings is the same as for the electric demand in general, i.e., that a 10% reduction in kW demand (which reduces local area peak demand by 8%) also reduces total consumption by 10%. Finally, the marginal costs of DSM programs are assumed to increase in proportion to the amount implemented.[8]

All three scenarios include current energy-efficiency programs being promoted by the City, resulting in 10 MW of peak savings by 2003. This effort includes, among others, the SF PUC's implementation of the Mayor's Energy Conservation Account and on-going commercial-sector efficiency programs implemented by the SF Department of Environment.

---

[6] We assume that this CCGT plant involves two separate gas turbines and a steam turbine with supplemental firing capability, such that the loss of one unit would decrease total plant output by no more than 200 MW. This is necessary to meet reliability requirements, because if the entire 540 MW capacity could be lost at once, the system would still need adequate capacity to meet peak demand without the plant under first contingency conditions.

[7] The solar PV capacity values represent 75% of the rated output during times of peak demand.

[8] Marginal cost is the cost of the last and most expensive measures implemented, after cheaper measures have been exhausted. The cost function is assumed increase linearly with savings, such that the marginal cost of saving 10% (of total usage) is \$1000/kW, or \$1250/kW of coincident peak load. Average costs are about two-thirds as much.

In the CG scenario, this activity is followed by a modest amount of additional savings (3 MW/year) being achieved in later years. Savings in total consumption reach 4% (3% peak demand) in 2012. These savings result from the use of State programs such as the Public Goods Charge (PGC) funding for energy efficiency.

In the MI scenario, following the 10 MW of savings achieved in 2003, additional City programs result in greater savings (6 MW/year) in the later years. Saving in total consumption reach 8% (6% peak demand) in 2012.

In the DR scenario, aggressive implementation of City efficiency programs, together with leveraging of private capital via energy service companies (ESCos), produces more than 100 MW of savings by 2012. Savings in total consumption reach 12% (9% peak demand) in 2012.

Assumptions on Electricity Imports and Transmission Capacity

The current 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. Total existing transmission capacity into 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 the San Francisco transmission planning study shows that a City load of 1057 MW,[9] 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.

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).

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 Peninsula (in 2002), the City's 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.

In addition, the San Francisco Operating Criteria require in-City generation of 40% of the City load, which corresponds to the high-value "downtown network" load.[10] This currently requires about 380 MW of generating capacity, which is met by the two steam plants at Hunter's Point and Potrero. This requirement will increase under our scenarios to 420-460 MW by 2012.

---

[9] 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.

[10] Environmental Science Associates, 1998. *Draft Environmental Impact Report for Pacific Gas and Electric Company's Application No. 98-01-008*, section 4.12.

While all of the scenarios include transmission upgrades within the City, only the More Imports scenario involves a major transmission expansion. In MI, a new 230-kV transmission line (420 MVA normal rating) from the Jefferson substation in Redwood City to the City's Martin substation adds about 350 MW of additional power import capacity. This line, which is assumed to be in service in 2006, makes it possible to close the Hunters Point station at that time.

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 any explicit effort by the City of San Francisco to influence energy planning in Peninsula communities, the SFO airport and its tenants are municipal electricity customers. Also, we assume that aggressive programs to support energy efficiency and solar energy in the City will indirectly stimulate a moderate increase in the use of these resources on the Peninsula as well.

There is presently a co-generation facility at SFO airport, which exports about 25 MW net to the Peninsula grid. After 2002, a 57 MW combined-cycle gas turbine (CCGT) unit will be installed at SFO under all scenarios. This generation capacity at SFO makes additional import capacity available to the City, via 115 kV line #5 San Mateo-SFO-Martin.

Other Peninsula resources include a modest 500 kW of annual energy efficiency improvements, increasing to 2 MW/year in the DR scenario. We also assume that 500 kW/year of solar PV resources are developed on the Peninsula under MI, increasing to about 1 MW/year under DR, or about 10 MW total capacity by 2012.

Assumptions on Electricity Supply Resources outside San Francisco

San Francisco already has its own generation resources at the Hetch Hechy hydroelectric facility, which has a maximum capacity of 400 MW. The total amount of energy supplied to San Francisco is limited by existing contracts to sell power to the irrigation districts of Modesto and Turlock. Present deliveries to San Francisco are about 900 GWh/year, and these increase during the scenarios in proportion to the City's demand growth.

No additional resources are assumed in the CG scenario.

The MI scenario includes incremental improvements to existing base-load generation at Hetch Hetchy, and a modest number of wind turbines in Alameda County, are developed to serve the City. Improvements at Hetch Hechy provide 24 MW average and 20 MW peak by 2008. Wind power capacity with a rated output of 50 MW provides 17.5 MW average and 15 MW peak by 2004.

Under the DR scenario, the improvements at Hetch Hechy are supplemented in 2006 by the addition of 65 MW of pumped storage capacity, which adds to output capacity during times of peak demand. More aggressive wind power development includes a total of 150 MW of rated capacity by 2010, producing 52.5 MW average and 45 MW peak.

Results of the Scenarios

Energy and Peak Demand

Following the bottom-up analysis approach, we treat energy efficiency and peak load management as an energy resource comparable to new electricity supplies. Therefore, we present the results 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 earlier, we ensure that adequate transmission capacity for power imports is available, and that reserve margins are sufficient to satisfy first-contingency planning conditions.[11]

The results of the CG scenario are shown in Figure 2, which gives peak MW demand and supply capacity values, and Figure 3, which gives total MWh use and energy supply values. Figure 2 shows clearly that the new CCGT unit 7 at Potrero dominates the electric supply capacity mix in this scenario. Hunter's Point is closed in 2005, while Hetch Hechy and other imported power play a secondary role.

[11] 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).

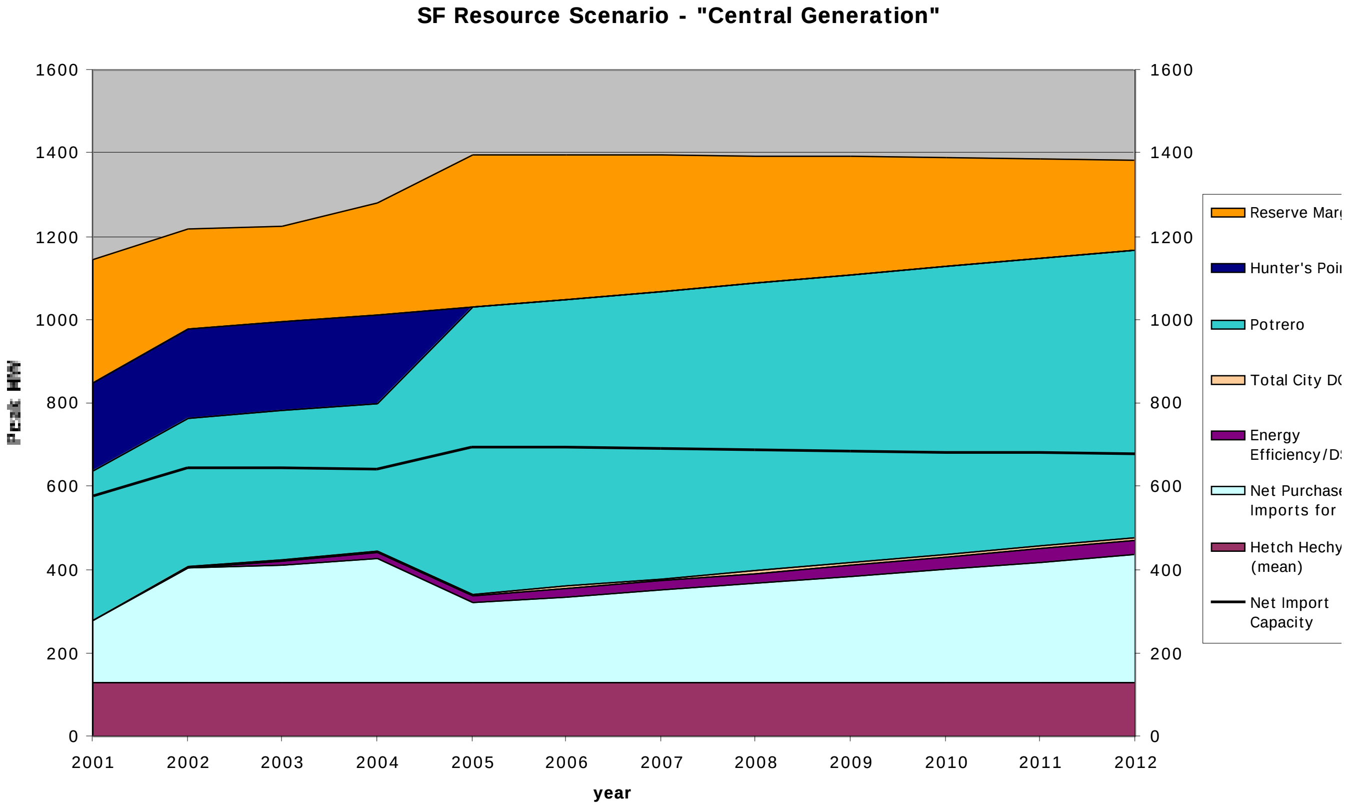

Figure 2. Resources to Meet Peak Demand – Central Generation Scenario

The solid line in the middle of Figure 2 shows the transmission capacity available for imports, which must exceed the total MW from Hetch Hechy and other imported power. Both the available transmission capacity and the reserve margin, shown as the top bar in Figure 2, are adequate through most of the scenario. Near 2012, however, it appears that both the import transmission capacity and the reserve margin are tightening. Thus, an additional resource such as the Jefferson-Martin transmission line project may be needed toward the end of the scenario timeframe.

Figure 3 shows that the new CCGT unit 7 at Potrero dominates the total energy requirements, as it did the peak demand coverage. Hetch Hechy and other imported power also make significant contributions to the energy requirements.

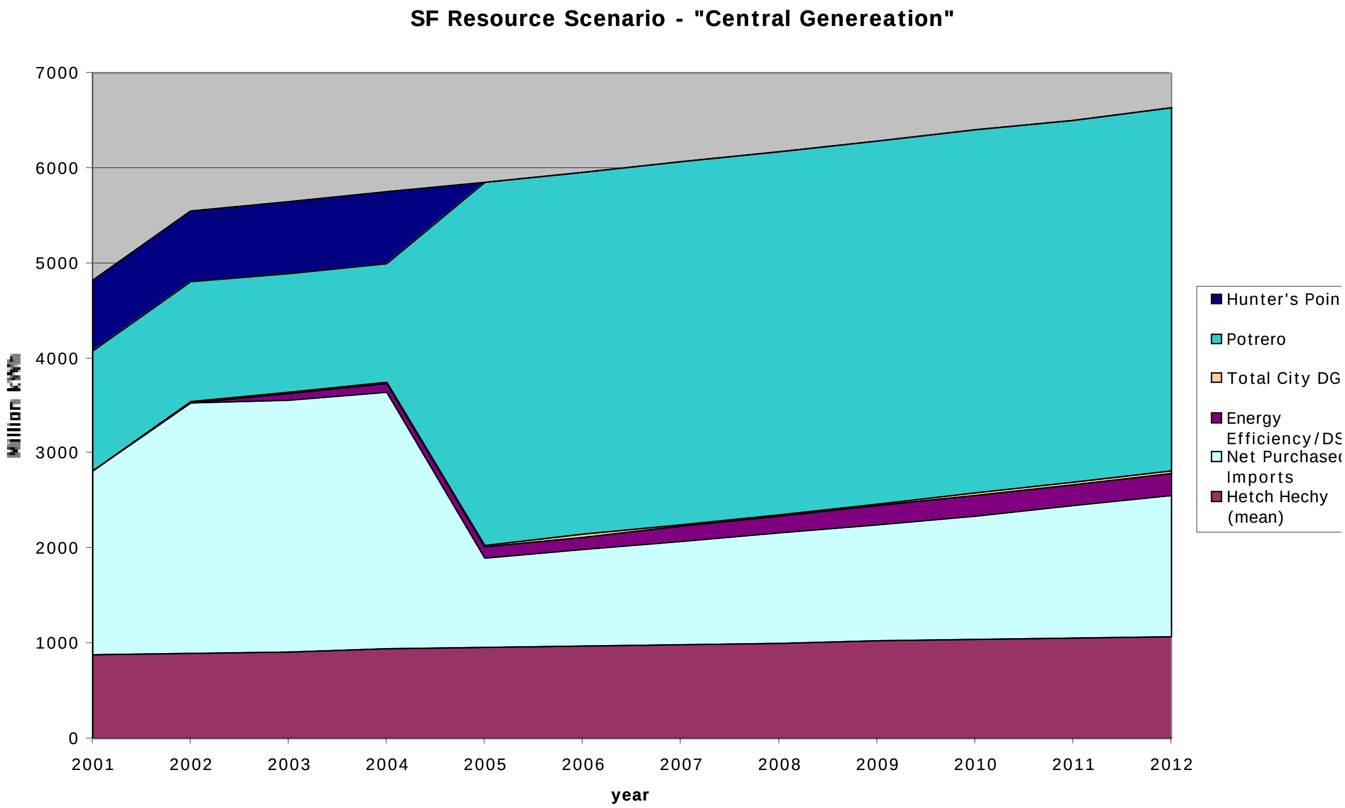

Figure 3. Resources to Meet Electric Energy Demand – Central Generation Scenario

The results of the MI scenario are shown in Figure 4, which gives peak MW demand and supply capacity values, and Figure 5, which gives total MWh use and energy supply values. Figure 4 shows that the dominant supply source is purchased imports, and that the import transmission capacity is adequate for these imports as well as the power supply from Hetch Hechy. Hunter's Point is closed in 2006.

The only major in-City source is the upgraded Potrero facility, although the impact of energy efficiency and other DSM programs becomes noticeable in this scenario. The importance of Potrero in this scenario could create a reliability problem, as the CTs might not be available during enough hours to consider their full capacity as firm resources available to meet peak demands, in which case additional in-City generation may be needed during the scenario.

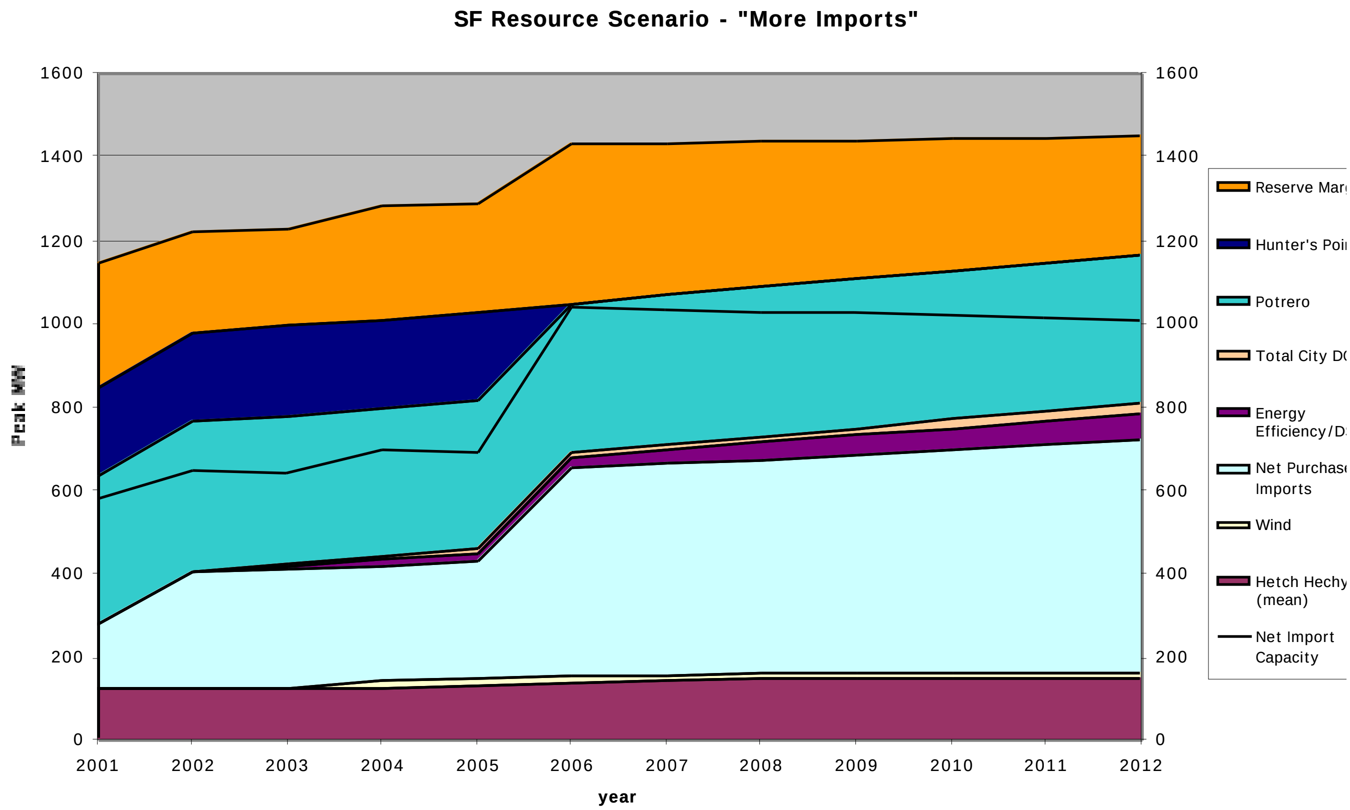

Figure 4. Resources to Meet Peak Demand – More Imports Scenario

Figure 5 shows a similar pattern for total energy use, as purchased imports dominate energy supply, followed by Hetch Hechy and Potrero.

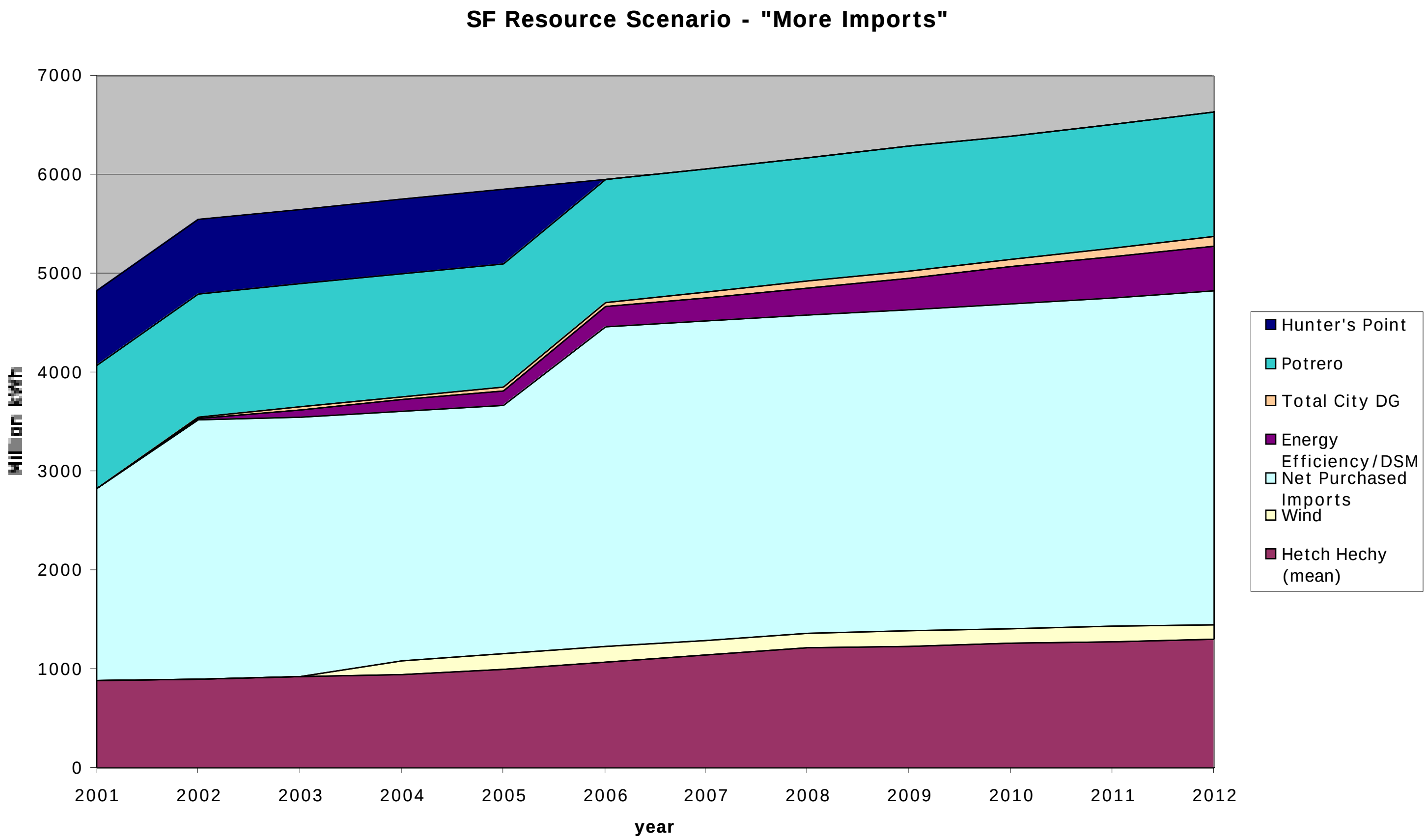

Figure 5. Resources to Meet Electric Energy Demand – More Imports Scenario

The results of the DR scenario are shown in Figure 6, which gives peak MW demand and supply capacity values, and Figure 7, which gives total MWh use and energy supply values. In terms of MW capacity to meet peak demands, San Francisco is more reliant on its own relatively diverse resources and less dependent on imports, although Hetch Hechy still plays a significant role. Important contributions to peak demand come from the new City-owned generating plant, a variety of distributed generation sources, and the upgraded Potrero facility, which is used explicitly to meet loads during times of peak demand. Energy efficiency and DSM also play a significant role.

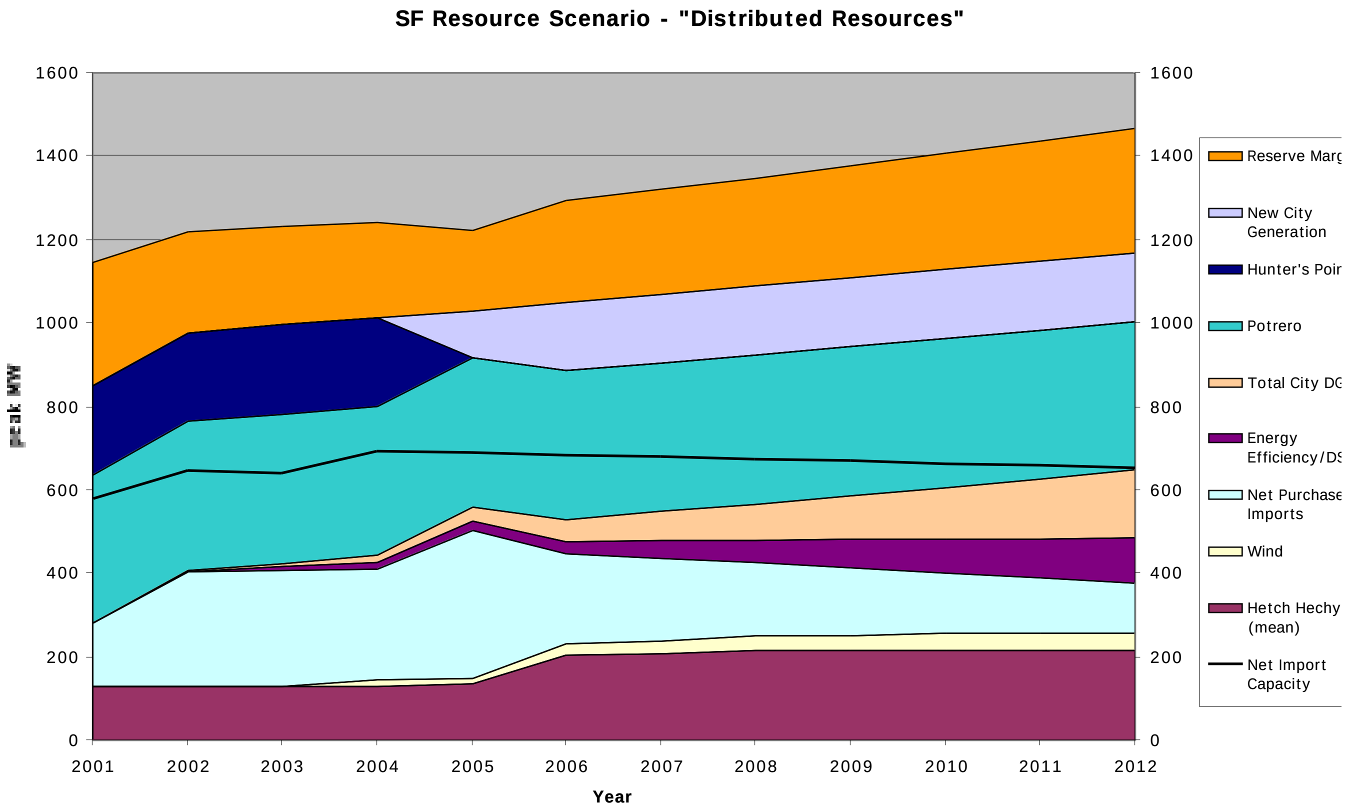

Figure 6. Resources to Meet Peak Demand – Distributed Resources Scenario

In terms of total energy use, Figure 7 presents a rather different picture in this scenario. Potrero makes relatively little contribution, and purchased imports are a more important source of energy than of peak capacity. The remaining energy demand is met by a diverse set of resources, including the new City-owned generating plant, distributed generation sources including solar PV and fuel cells, wind farms in Alameda County, and Hetch Hechy.

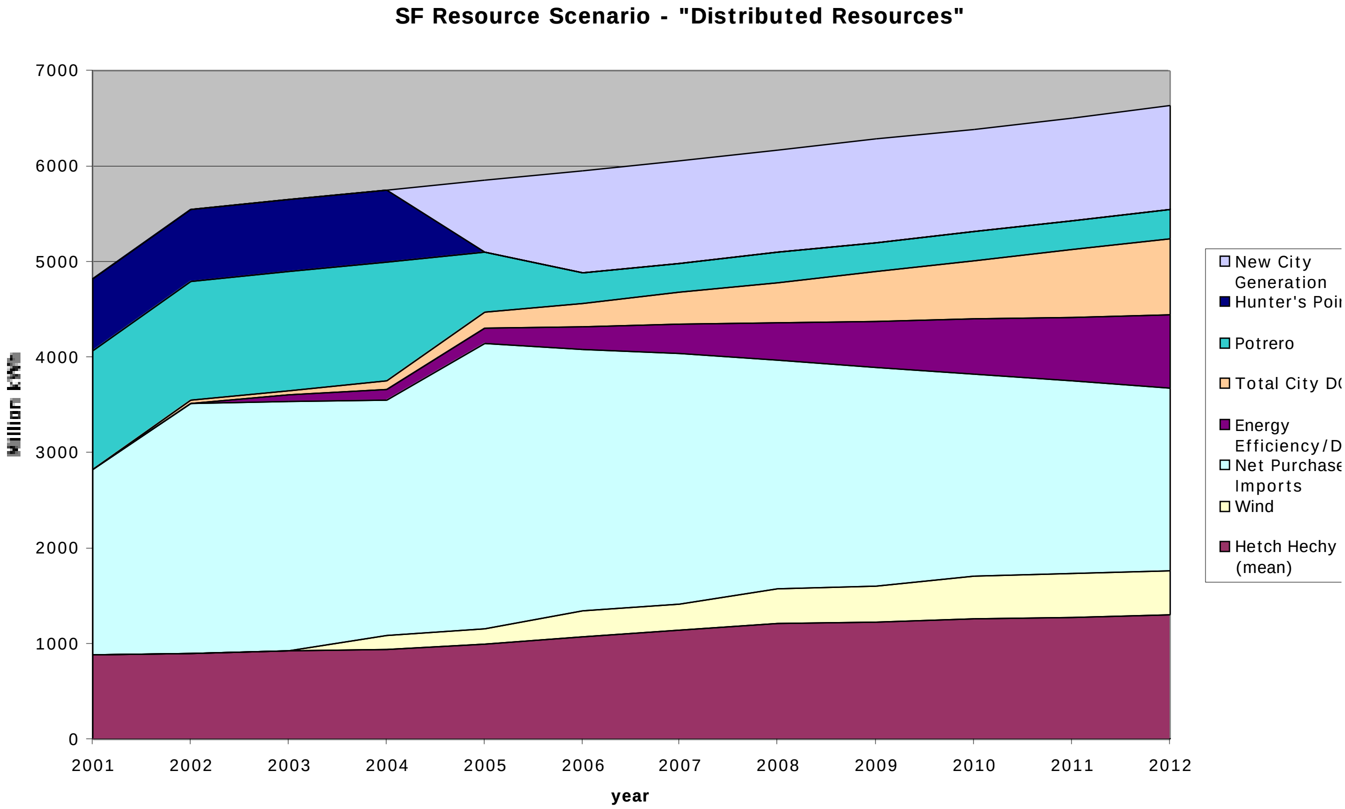

Figure 7. Resources to Meet Electric Energy Demand – Distributed Resources Scenario

Capital and Operating Costs

One of the fundamental elements in a full 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. At this preliminary stage of the analysis, we are not able to assess the economics of each option in sufficient detail to fully evaluate and optimize an ERIS on an economic basis. However, we have made an initial cost analysis in order to identify basic trends and potential concerns in each scenario.

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. Operating costs include general operation and maintenance (O&M) costs, transmission charges, and credits (negative costs) for co-generated thermal energy.

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 (an oversimplification that ignores 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.

The overall results for the scenarios are shown in terms of capital costs in Figure 8. The largest capital investments occur mostly in 2005-2006, when the major facilities needed to replace Hunter's Point are installed. These include Potrero unit 7 ($450 million) in CG, the Jefferson-Martin transmission line ($190 million) in MI, and the new City generation, a large co-generation project and the pumped storage capacity at Hetch Hechy in DR. Also, on-going investments in distributed generation, renewable energy, energy efficiency and DSM require significant capital investments during the later years in the DR scenario.

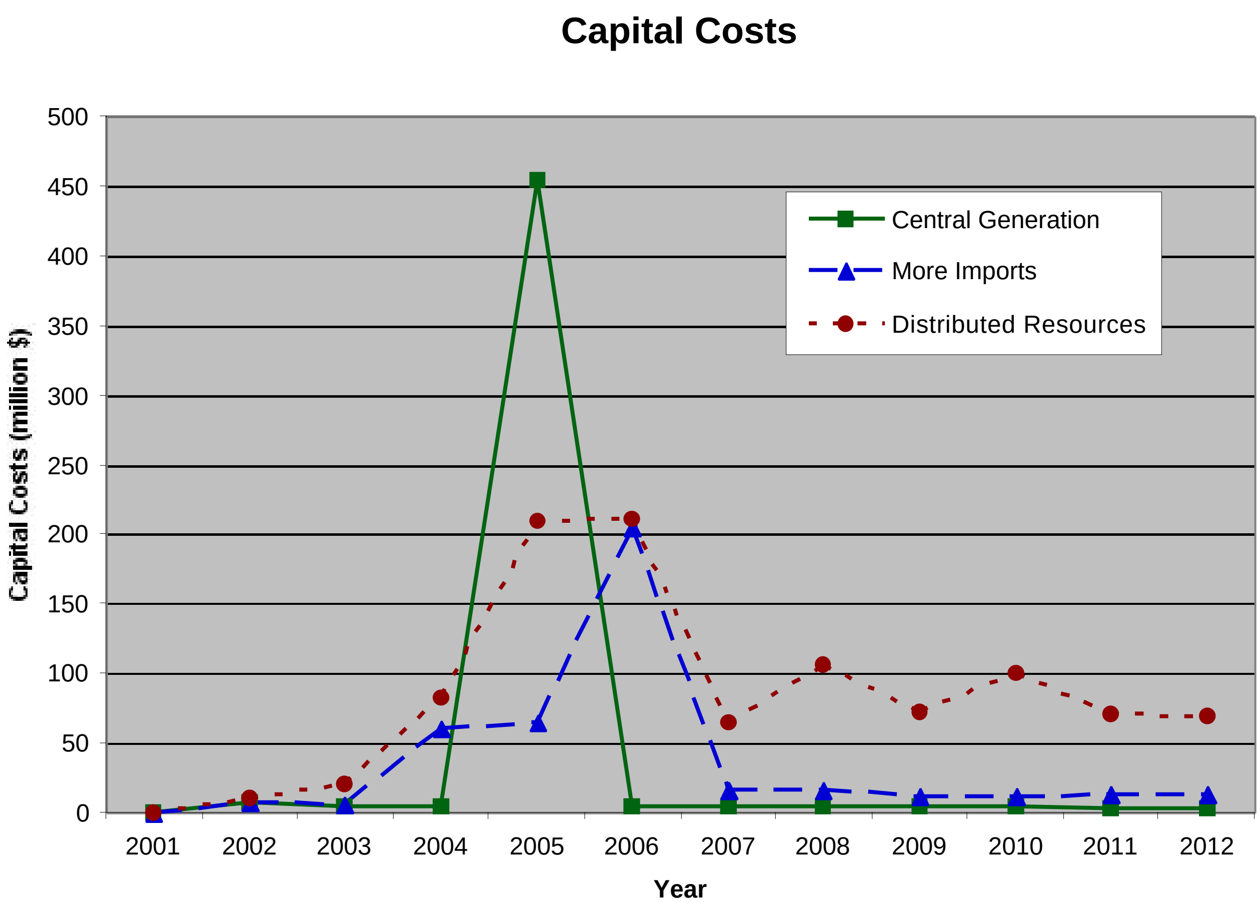

Figure 8. Capital Costs for Technologies Installed in Each Scenario

The overall results for the scenarios are shown in terms of annual fuel and other operating costs in Figure 9. Operating costs drop in DR, and especially in CG, because the new generation sources are more efficient than the generators they replace at the existing Hunter's Point plant.

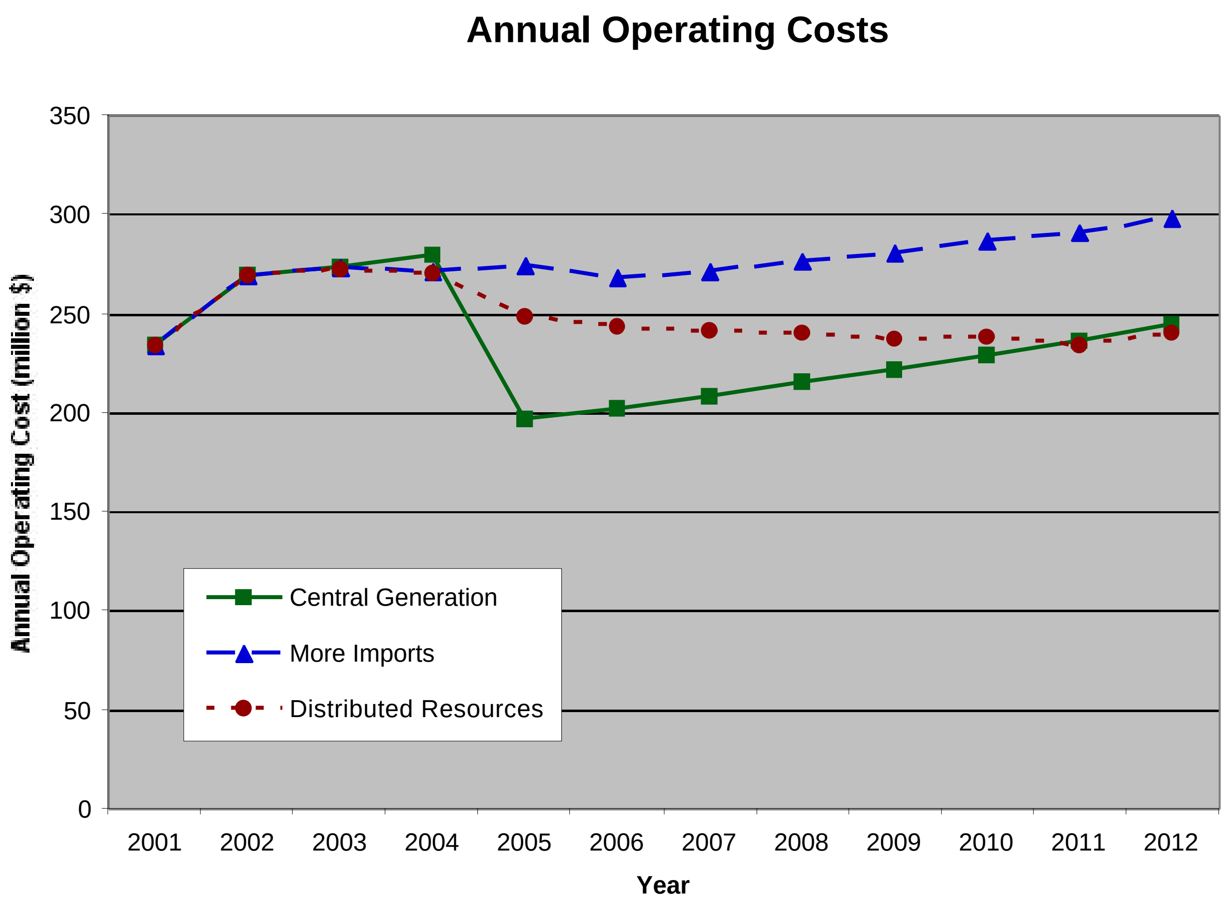

Figure 9. Fuel and Other Annual Costs for Technologies Operating in Each Scenario

Costs remain rather high in MI because the imported power costs are considered to be mostly operating costs (as opposed to capital costs) in these estimates. In MI and even more in CG, operating costs increase over time with the increasing demand for electricity. In DR, energy efficiency programs mitigate this load growth, replacing megawatts with "negawatts" to a significant extent, causing annual operating costs to decline slightly as net power imports are reduced.

The overall results for the scenarios are shown in terms of the total cost per MWh of energy services delivered in Figure 10. For these calculations, the capital costs shown in Figure 8 are annualized over 20 years at a real (net of inflation) discount rate of 4.5%. Then, the total annualized costs (annual operating cost plus annualized capital costs) are divided by the total energy service demand to arrive at a total cost normalized per MWh.

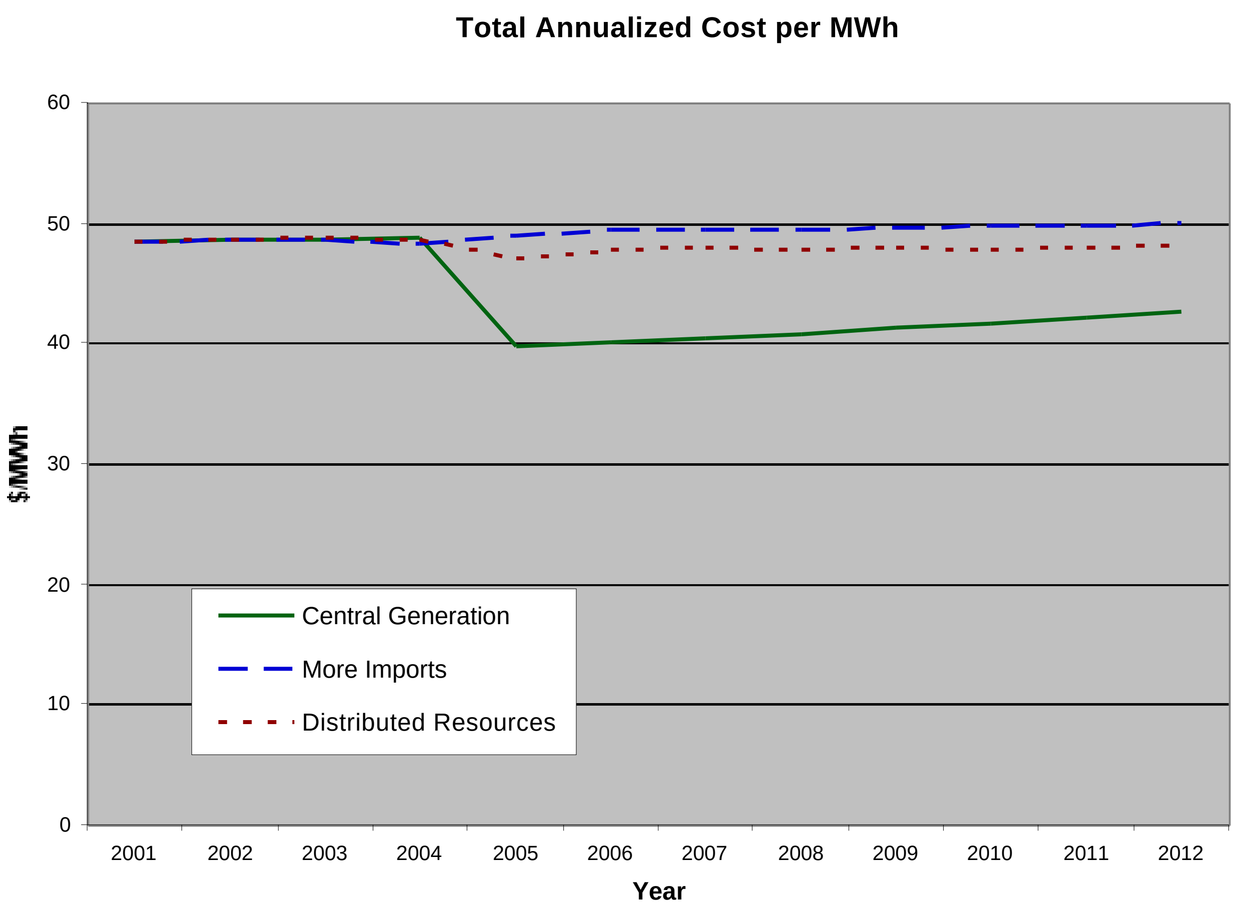

Figure 10. Total Annualized Costs per MWh for Energy Services Delivered in Each Scenario

As shown in Figure 10, the total cost of delivering each unit of energy services does not increase significantly in any of the scenarios. Note that this cost level is far below the current retail commercial electricity tariffs in San Francisco. In CG, the cost falls significantly as soon as the Hunter's Point plant is replaced by the new CCGT at Potrero unit 7.

This cost reduction indicates that the lower fuel and operating costs of the new unit more than compensate for its additional capital cost on an annualized basis. However, there are several factors that could make this initial capital cost estimate increase significantly after more detailed analysis. First, the cost of capital could be substantially higher than the 4.5% real discount rate used here. Second, because of its dominant role in supply power to San Francisco under this scenario, the plant's owner (Mirant) could sell some or all of the power at prices significantly above its own costs. Finally, our capital cost estimate ($450 million) could be too low.

Total units costs under MI and DR are similar to the current costs. The costs under MI are especially dependent on the price of imported power, which can vary in either direction from our estimates.

The costs in DR are based mostly on the present costs of a number of renewable and distributed generation technologies, including solar PV, wind, fuel cells, microturbines and gas-fired cogeneration. These are relatively new technologies, although most of them are widely used throughout the world. Their costs are therefore less certain than the costs of more mature technologies, and these costs could turn out to be higher than we have estimated.

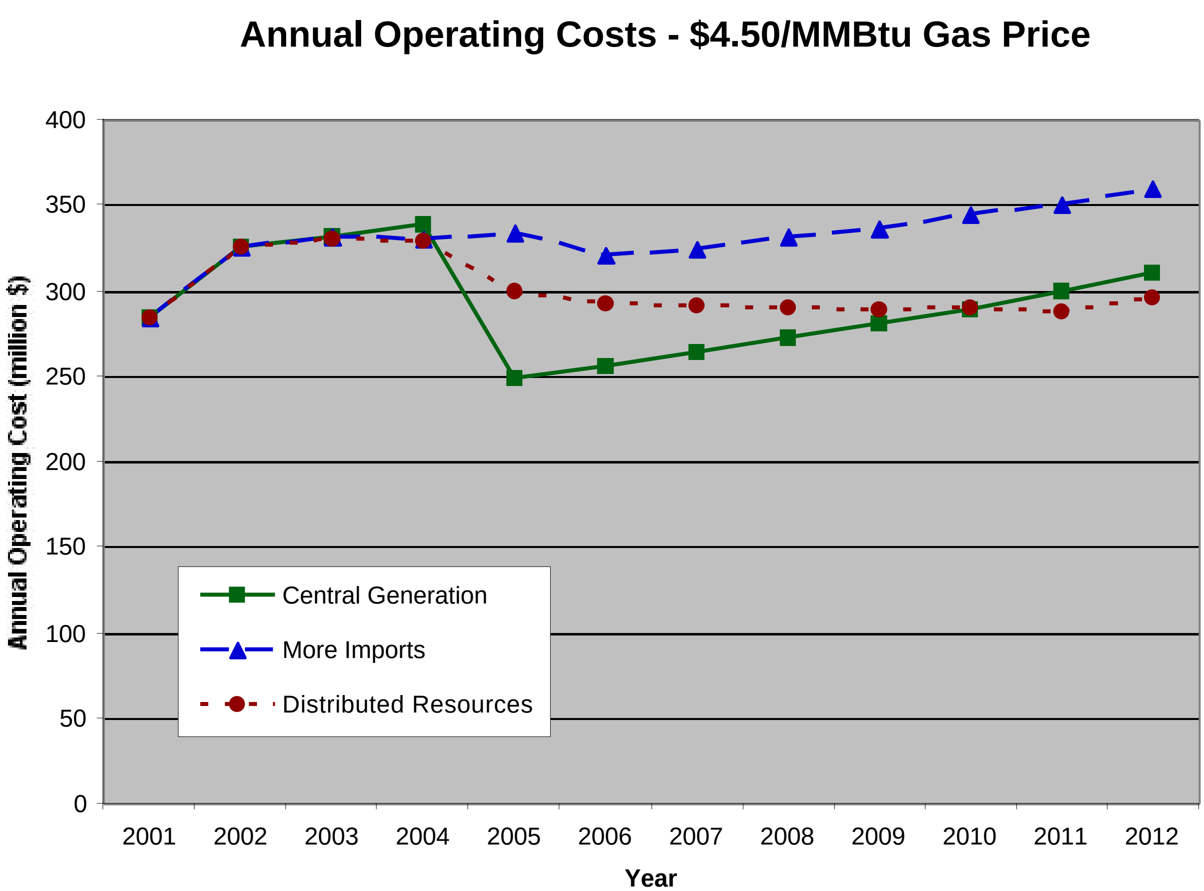

Figure 11. Fuel and Other Annual Costs for High Fuel-Cost Scenarios

On the other hand, costs of some technologies such as wind turbines have been falling steadily, and it is reasonable to expect significant cost reductions in the other technologies as they mature and expand their markets. Any cost breakthroughs in these technologies would make this initial capital cost estimate decrease significantly.

Another cost issue in favor of the technologies used in the DR scenario is that the cost of capital could be somewhat lower than the 4.5% real discount rate used here. Because these technologies can be financed using low-cost tax-exempt municipal bond financing under Propositions B and H, the lower cost of capital could create a significant cost advantage. This advantage applies in all the scenarios, but especially in DR.

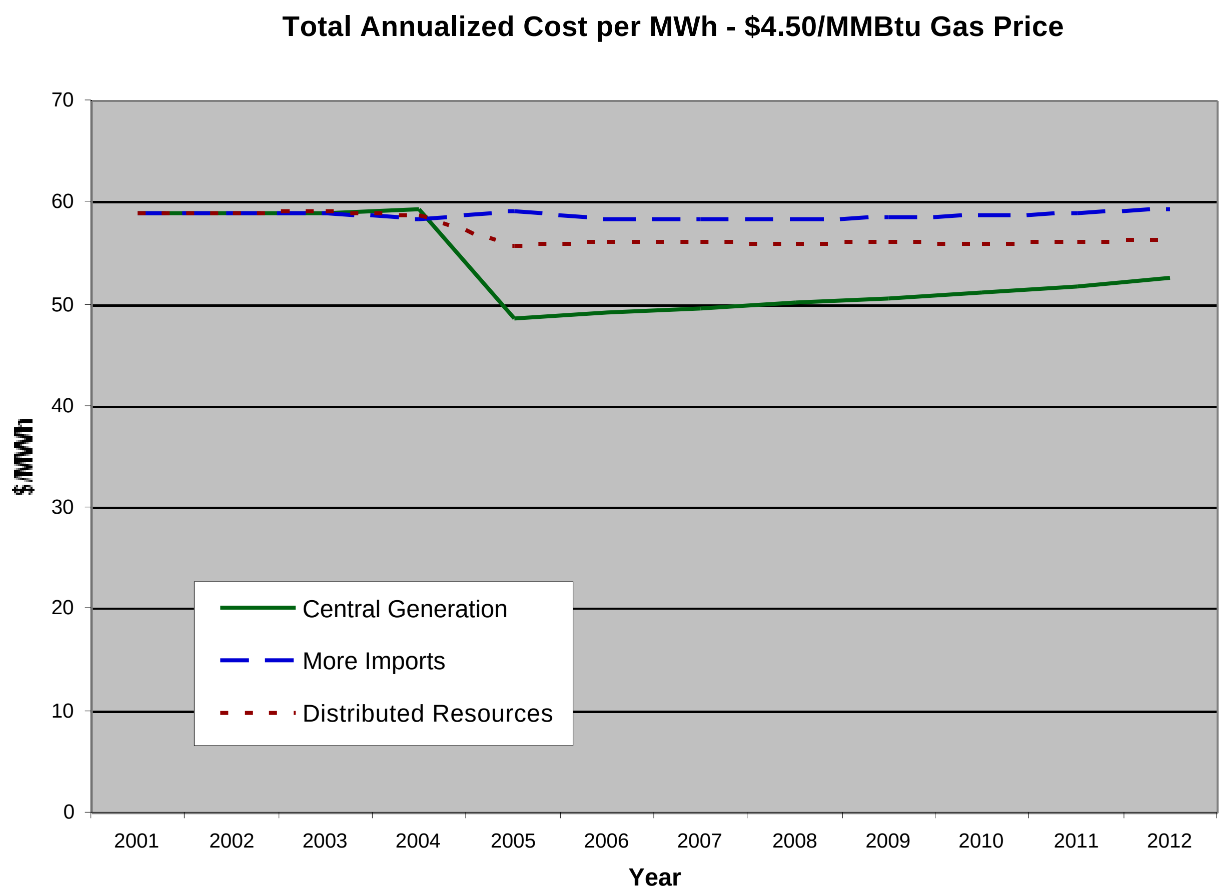

Figure 12. Total Annualized Costs per MWh for High Energy-Cost Scenarios

The cost analysis was based on an assumption that natural gas costs would be $3/MMBtu, escalating at 2%/year above inflation. Because fuel costs are one of the main components of the total cost of supplying electricity service in each of the scenarios, we performed a sensitivity analysis on this gas price assumption. Instead of $3.00/MMBtu, we assumed that the base natural gas price is $4.50/MMBtu. The results of this change are shown in Figure 11.

The effect of higher gas prices is, not surprisingly, to increase operating costs in all scenarios. Each scenario uses similar total quantities of gas, although in much different types of facilities and locations. As a result, the total annual cost increase, about $50 million per year, is roughly the same in all three scenarios. This result is also shown in Figure 12, which gives the total cost per MWh of energy services delivered. Total cost per MWh increases in each scenario by about $9/MWh, or roughly 20% compared to the same scenarios under a $3.00/MMBtu base gas price.

A Note about Distribution Costs

This preliminary cost analysis considers generation costs and bulk transmission costs on the supply side. It also accounts for the costs of demand-side measures such as energy efficiency and load management technologies that can replace a certain amount of generation. We have not, however, included local transmission and distribution costs in the scenarios for the purpose of this analysis. Our initial review of the local transmission needs in the City indicates that similar upgrades will be necessary under all the scenarios.

Distribution costs, however, could vary significantly, and targeted DG and DSM can offset costs in the distribution system, providing economic benefit to the utility system. Until recently, most utilities treated T&D costs as unavoidable consequences of generation network expansion, based on engineering rules of thumb designed to maintain accepted system reliability criteria.

However, recent analytic advances in determining utilities' area- and time-specific (ATS) costs more accurately have important implications for the siting and design of DG sources and targeted DSM programs.[12] One consistent result of ATS analysis is that T&D costs vary widely in time and place, which allows precise targeting of DG projects and targeted DSM programs in areas where the *distribution utility costs are relatively high* (see Figure 13). By selectively targeting such projects and programs, it is possible (albeit still difficult in practice) to reduce utility costs by deferring the need for investments to expand the distribution system.

Utilities such as PG&E have strict rules governing connection between a DG source and the grid, as an incorrect connection can endanger the system and utility personnel. Typical rules require detailed engineering studies, utility-grade switches, batteries, dedicated isolation transformers, fault-current-limiting reactors and other protection equipment, automated control, monitoring and telemetry equipment. On the other hand, utilities make relatively little effort to encourage proper connections to DG sources, and to realize the potential economic and operating benefits. In addition to capacity deferral, DG can provide economic benefits to distribution utilities by reducing costs in the operation and maintenance of T&D systems. The potential benefits include:

- Reduction of Losses. DG can reduce system losses by reducing the current flow from the transmission system through the transformers and conductors on the distribution system. DG-based loss reduction also reduces the distribution utility's total installed capacity (and corresponding cost) as seen by the transmission system.
- Voltage Support. DG can support voltage in areas of the distribution system that suffer large drops at high loads, replacing voltage regulators and line upgrades. Voltage support is

[12] 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.

provided by injecting power into the system at the DG site, thereby reducing the current and corresponding voltage drop from the substation to the area. DG can also regulate voltage by balancing fluctuating loads with generation output.

- Reactive Power Support.[13] DG can help balance reactive power flows on a distribution system with both real and reactive power injection. Real power injection reduces current in the conductors, which is a major source of reactive power demand that is typically treated with banks of capacitors. Improved reactive power flow (as indicated by a higher power factor) reduces current and losses on transmission and distribution components, and helps control system voltage.
- Equipment Life Extension. DG can provide value for equipment life extension in aging facilities, especially if transformers and feeder lines are under heavy loading. If DG is used to keep loading levels on these facilities below a predefined de-rated value, the DG source can defer the transformers' or lines' replacement costs.

Conventional approach:
Based on system-level costs,
all areas look the same…

Based on area-specific costs:
Some high cost (red) areas are attractive for DG now,
but these areas become low-cost (green) areas later.

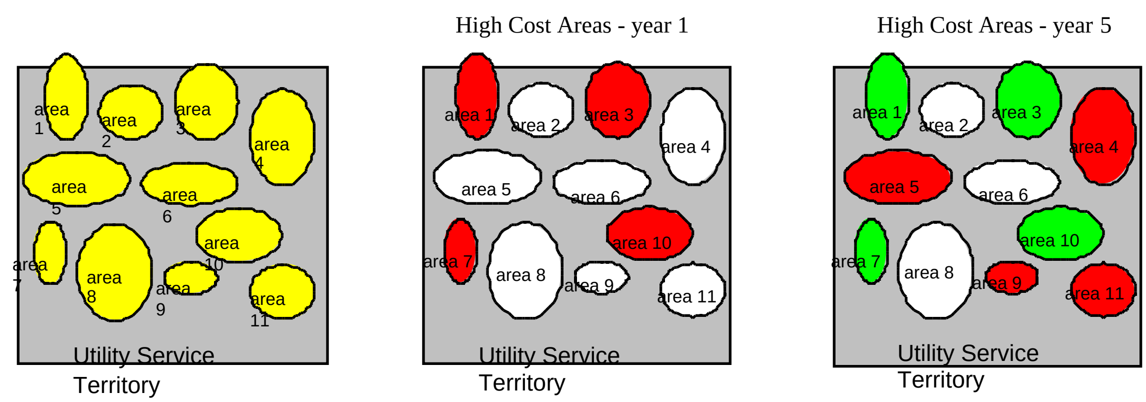

Figure 13. Comparison of Conventional DG Siting to Targeted (ATS-based) Approach

Aggressive implementation of DG, as in the DR scenario, would require more detailed study of the requirements for interconnection to the grid, costs of interconnection, and potential cost savings from advantageous siting of DG sources. In addition, detailed ATS analysis of the costs of maintaining and upgrading the San Francisco distribution grid could reveal opportunities to use targeted DG and DSM to reduce distribution utility costs. Such savings could provide win-

[13] Reactive power is a measure of energy stored in the oscillating inductance and/or capacitance of a power delivery system with no net gain or loss. Reactive power is indicated by the *power factor*, which is the ratio of real power supplied (kW) to the apparent power (kVA) and is equal to the cosine of the phase-angle between the supply voltage and current. Reactive power demand (measured in kVAR) increases the current needed from the power system, which increases system losses, and can also cause a voltage drop in T&D lines. To reduce these effects, electric utilities use *reactive-power compensation* and may pass on the cost of compensation to the user in the form of a penalty for power factors low enough to require compensation.

win benefits to the utility and its customers, and we encourage PG&E and the City to cooperate in investigating this issue further.

The bottom line result in terms of distribution costs in the scenarios is that these costs are too uncertain to include in the present analysis, as ATS cost analysis is beyond the scope of the present work. However, based on experience with such analysis in other areas, including parts of PG&E's service territory, we suspect that targeted DG and DSM could provide cost savings in the distribution system. Such savings would favor a scenario such as DR.

Electricity Supply Reliability

One of the underlying trends, or predetermined elements, assumed in all the scenarios is the growing demand for high electric supply reliability. Premium reliability can have a very high value in sensitive industries such as data centers, semiconductor fabs and many conventional businesses as well. These businesses are not simply inconvenienced by a power outage; they can be crippled by even a brief outage. Thus, growth of the digital economy translates into growing demand for premium-reliability power.

Contrary to some widely cited claims, this demand 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.[14] 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 only the generation and bulk transmission components of the electricity supply system in detail. 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 here. In fact, one of the most promising aspects of DG technology is the potential to provide improved customer reliability using a combination of DG and grid power. Assessing the benefits and costs of this strategy is, however, beyond the scope of this study.

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,
- Total transmission capacity to import power into the City , and
- In-City generation capacity to serve City loads without imported power.

[14] 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.

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 San Mateo substation. All loads in the City or on the Peninsula north of San Mateo tend to reduce the reserve margin. All generation resources and peak-coincident DSM resources in these areas tend to 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 reserve margin values for each of the scenarios are shown in Figure 14.

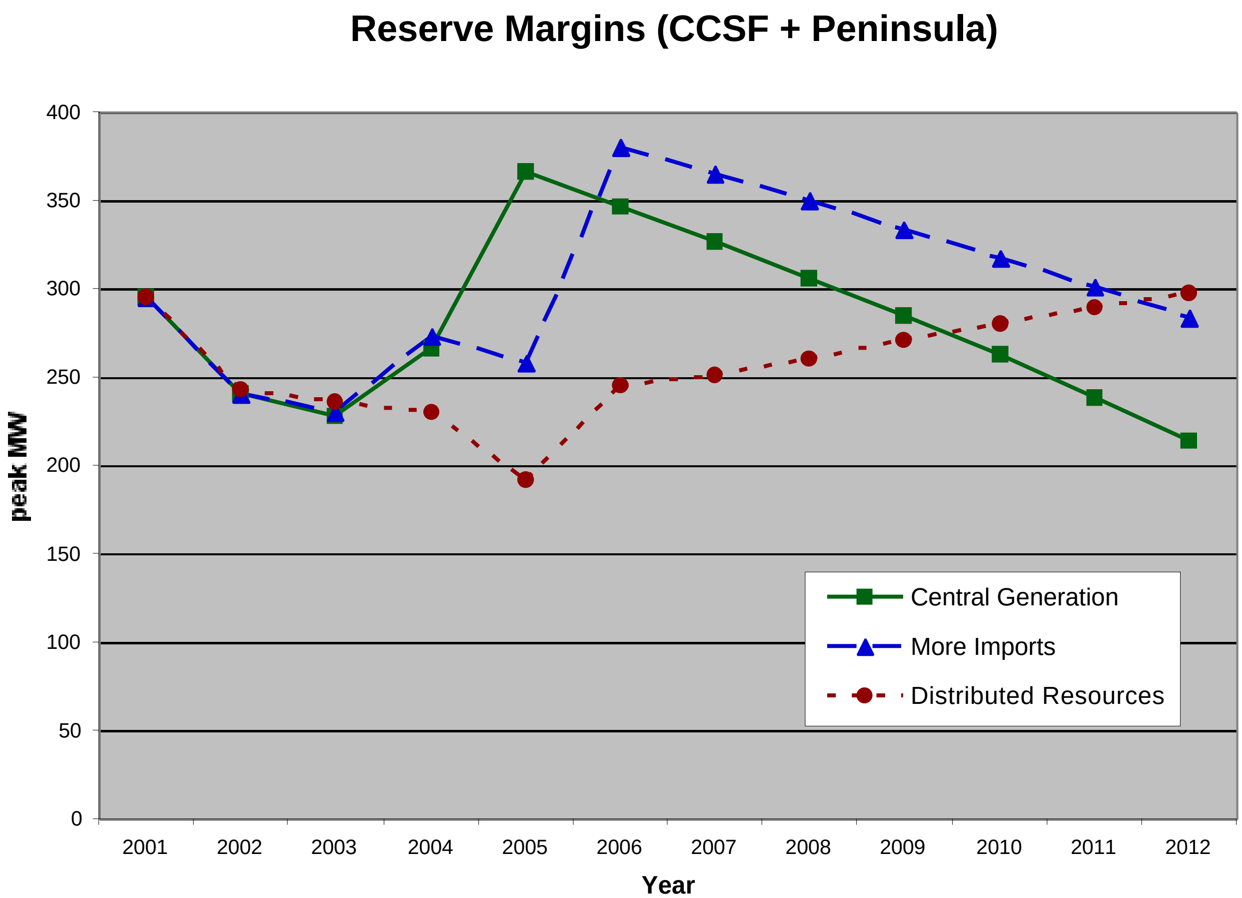

Figure 14. Reserve Margins in Each Scenario

The estimated reserve margin remain above 200 MW in all scenarios. This is the critical value because it is approximately equal to the capacity of the largest generating unit in each scenario (assuming that Potrero unit 7 can run at a capacity of at least 340 MW when one turbine is out of service). Thus, combined with the first-contingency planning built into the transmission system, this 200 MW reserve margin satisfies a double-contingency reliability criterion in San Francisco. In other words, the system can meet its maximum load despite a simultaneous failure of both the largest transmission component and the largest generation component.

In both CG and MI, the reserve margin increases in 2005-2006, when the major facilities needed to replace Hunter's Point are installed. These include Potrero unit 7 540 MW) in CG, the Jefferson-Martin transmission line (about 350 MW) in MI. After this time, load growth reduces the capacity margin, and it appears that additional resources are needed around the end of the CG scenario in 2012.

The DR scenario muddles through the early years, maintaining the reserve margin around 200 MW. Later, however, as the cumulative installed capacity of DG and DSM grows, the reserve margin increases to a comfortable level and surpasses that of the other scenarios.

In terms of total transmission capacity to import power into the City , the only difference between the scenarios is the addition of the Jefferson-Martin line under MI. This capacity value is shown, in comparison to the supply resources and total loads, in Figures 2, 4, and 6. This capacity is more than adequate in each scenario, assuming that all the planned in-City generation sources are available, although the spare capacity tightens around 2005-2006 in the DR scenario and toward the end of the CG scenario. The net import capacity, shown as a black line across Figures, 2, 4 and 6, exceeds the planned imports from Hetch Hechy, wind farms, and other purchases. The spare capacity or reserve margin can be seen in the orange band at the top of each chart.

The scenarios show varying degrees of reliability, however, in the event that planned in-City generation resources are not available. In this case, the total transmission capacity provides a measure of reliability for meeting City loads via imports. Relative to this criterion, the MI scenario has a large advantage due to the capacity of the Jefferson-Martin line. This line provides import capacity (net of Peninsula loads) under first-contingency normal operating conditions of over 1000 MW, which is nearly enough to meet the peak demand (net of DSM savings). Relaxing the first contingency condition, the total import capacity (net of Peninsula loads) of about 1300 MW is more than adequate to meet peak demand.

In the other scenarios, import capacity (net of Peninsula loads) is about 700 MW under first-contingency normal operating conditions and about 1000 MW of total capacity. The latter value would be nearly sufficient to meet the reduced peak demand under DR, but insufficient by more than 100 MW under CG.

In terms of in-City generation capacity to serve City loads even without imported power, the MI scenario has a large disadvantage compared to the other scenarios. To meet the 40% in-City generation requirement of the San Francisco Operating Criteria under MI, one would have to count the peaking CTs at Potrero and all DG sources, which narrowly satisfy this requirement in the early years but fall short near the end of the scenario (see Table 6).

In DR, the in-City generation requirement is met by the upgraded Potrero unit 3, the new City-owned generation, and the large cogeneration capacity. The peaking CTs and all the other DG sources add greater reliability. In CG, Potrero unit 7 alone meets the requirement, and the peaking CTs provide an additional cushion. Note, however, that the required power imports are increasing under CG, while the DR scenario has decreasing imports as additional DG and DSM capacity is added in the later years.

Table 6. In-City generation capacity to serve City loads in each scenario, 2012

Scenario	Central Generation	More Imports	Distributed Resources
In-City Generation (MW) 2012	697	381	683
Peak Demand (MW) 2012	1136	1105	1062
Ratio (%)	61%	35%	64%
Required Imports (MW) 2012	439	724	379

Environmental Quality and Equity

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 Hunter's 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 and use 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.

Table 7 lists our assumptions on the emissions of various technologies employed in the three 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.

The least efficient and most polluting technologies are clearly the existing Hunter's 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 nearly 85-

90%. On the other hand, the state-of-the-art CCGT in CG has much higher efficiency (thus lower CO_2 emissions) and lower NOx emissions. The new City-owned generation plant in DR is has somewhat lower efficiency and higher NOx than a new CCGT, but much better than the existing plants.

Table 7. Assumptions on emission intensities for electricity resources

Electricity Resource	CO2 [ton/MWh]	NOx [lb/MWh]
Hunter's Point	0.6	1.7
Potrero – unit #3 without retrofit	0.6	1.7
Potrero – unit #3 with retrofit	0.6	0.2
Potrero – Unit #7 new CCGT	0.4	0.1
New City Generation	0.45	0.1
Efficiency / DSM	0	0
Distributed Generation[1]	0.3	0.5
DG – Fuel Cells[1]	0.25	0.02
Solar	0	0
Biomass	0	0.2
Wind	0	0
Hetch Hetchy Hydro	0	0
Purchased Imports[2]	0.4	0.3

Notes: 1. Total co-gen emissions are attributed 50% to electricity, 50% to thermal energy. 2. Statewide average values, from California Energy Commission, 2001. *Environmental Performance Report of California's Electric Generation Facilities*, P700-01-001.

The various DG technologies are all fairly efficient, but produce much more NOx per MWh generated than a central CCGT (with the exception of fuel cells in the later part of the DR scenario). Cogeneration 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.

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.

Total emissions of CO_2 do not change dramatically in the CG and MI scenarios, although emissions in the City increase under CG and decrease under MI. Both in-City and total CO_2 emissions decrease in the DR scenario.

In the CG scenario, the most significant source of CO_2 emissions is the Potrero power plant, as shown in Figure 15. Although unit 7 is extremely efficient, its CO_2 emission intensity is the same as that of purchased imports that this plant replaces for the most part. The emissions benefit from replacing Hunter's Point is offset by the increase in total supply to meet demand growth.

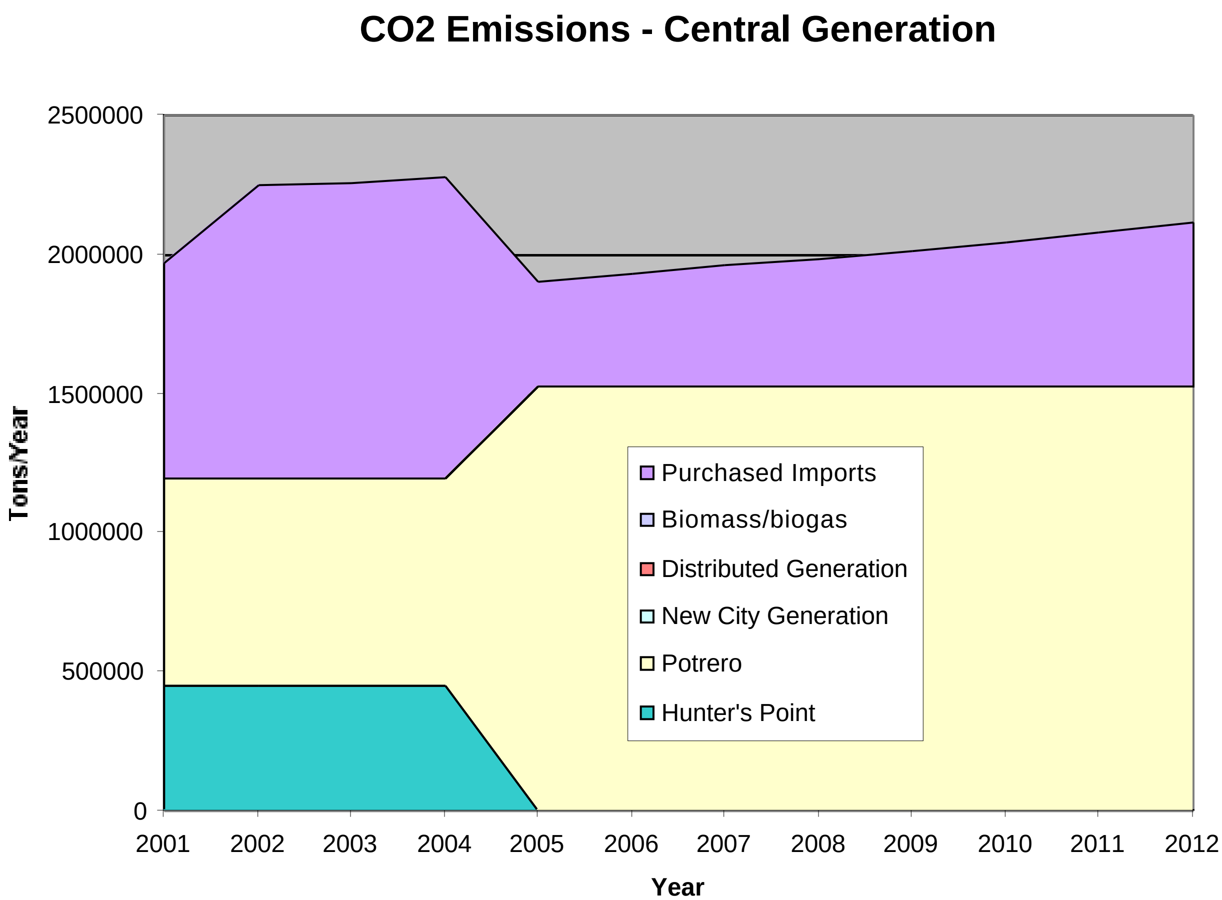

Figure 15. CO2 Emissions - Central Generation Scenario

The MI scenario primarily relies on importing power to meet the City's energy demand, and the resulting emissions profile is shown in Figure 16. As in the CG scenario, total emissions fall after Hunter's Point is shut down, but climb steadily as increases in system demand are met by more imported power. Potrero unit 3 emissions of CO_2 (but not NOx) remain steady after the unit's retrofit.

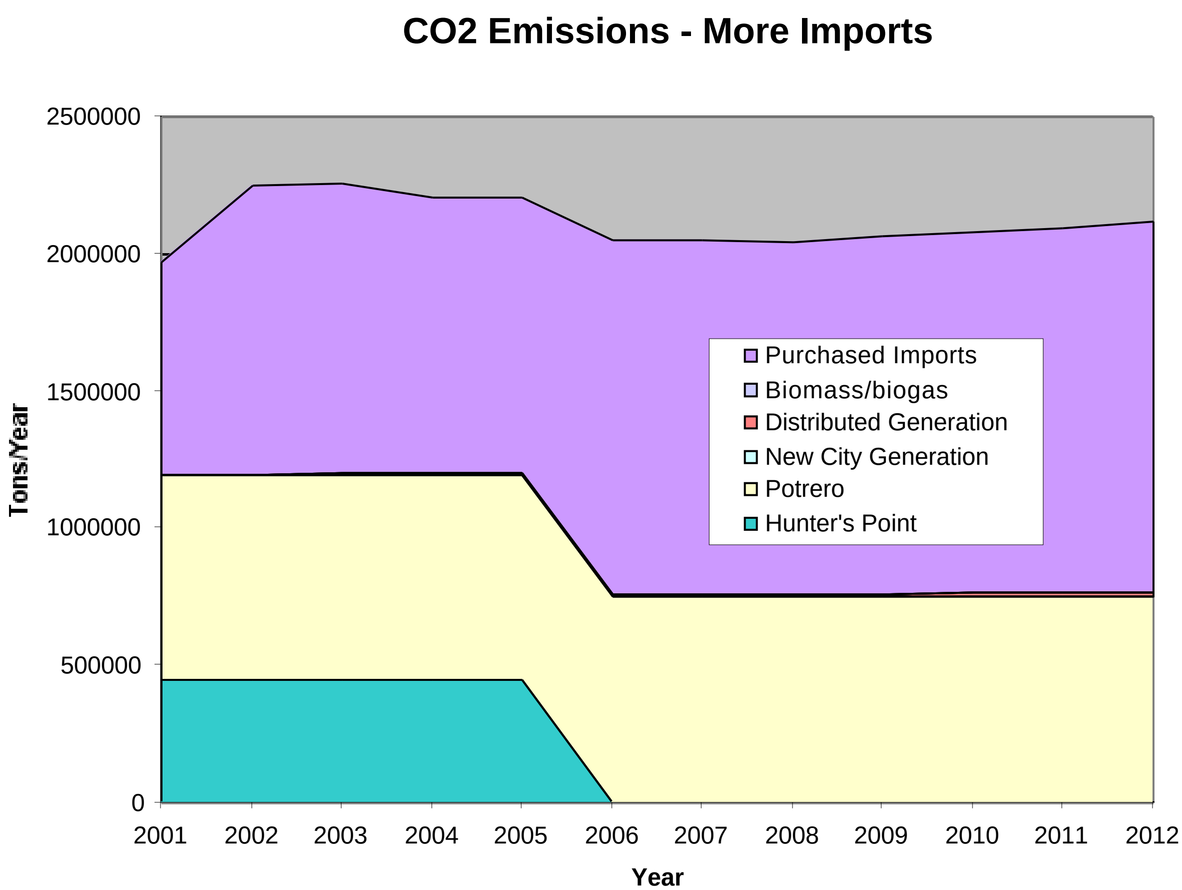

Figure 16. CO2 Emissions - More Imports Scenario

The DR scenario, shown in Figure 17, is the only scenario in which CO_2 emissions decrease. Moreover, emissions continue to fall at the end of the analysis period. This is because energy efficiency and the renewable technologies, which do not emit any CO2, are beginning to meet a more significant share of San Francisco's energy requirements.

For CO_2 emissions from the electricity sector, the year 2001 is rather similar to 1990, because the energy conservation efforts in 2001 reduced total demand to about the level of 1990 (roughly 4800 GWh). Assuming a similar power supply and emissions profile, we can use the 2001 levels shown in the figures as an approximate baseline for comparing future emissions to 1990 levels. On this basis of comparison, only the DR scenario shows net emission reductions. In fact, the reductions in DR amount to about 18% below the level of 2001, and presumably 1990.

Thus, the DR scenario appears to come close to meeting the emission reduction goal recently announced by Mayor Brown, assuming that the overall goal is applied to the electricity supply sector separately. Alternatively, if it is difficult to reduce emissions in other sectors such as transportation, deeper reductions would be needed in emissions from electricity in order to achieve the overall reduction target.

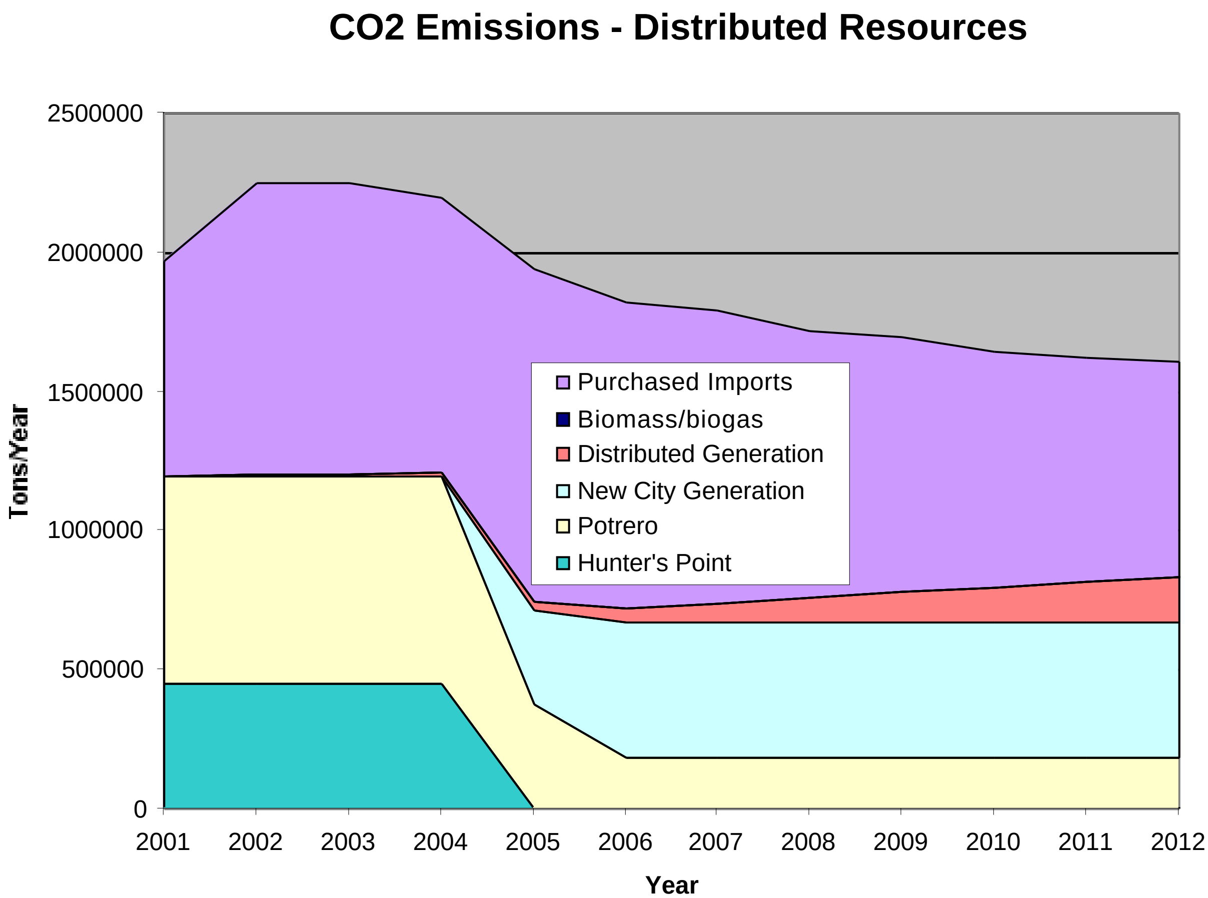

Figure 17. CO2 Emissions – Distributed Resources Scenario

The summary results of the scenarios are shown in terms of cumulative eight-year (2005-2012) emissions in Figure 18. The DR scenario clearly has the lowest in-city and total CO_2 emissions. This is due to its reliance on energy efficiency, renewable energy resources and high efficiency distributed generation. The CG scenario relies most heavily on a local power plant to meet its increasing energy demands. Because of the power plant's in-city location and fossil based technology, the in-city emissions are significantly higher than either the MI or DR scenarios.

With regard to NOx emissions, the local in-City emissions are as important or more important than the total emissions, because of the local health and air quality impacts. Fortunately, it appears that the technologies installed in all three scenarios are able to reduce NOx emissions dramatically. Total reductions are 70-80% in each scenario, and local in-City emissions are reduced by about 90% in all scenarios.

In all of the scenarios, the most dramatic reductions in NOx emissions result from shutting down the Hunter's Point plant and either shutting down Potrero unit 3 or upgrading its emissions control equipment. Beyond these vast improvements, the differences between the scenarios become relatively small.

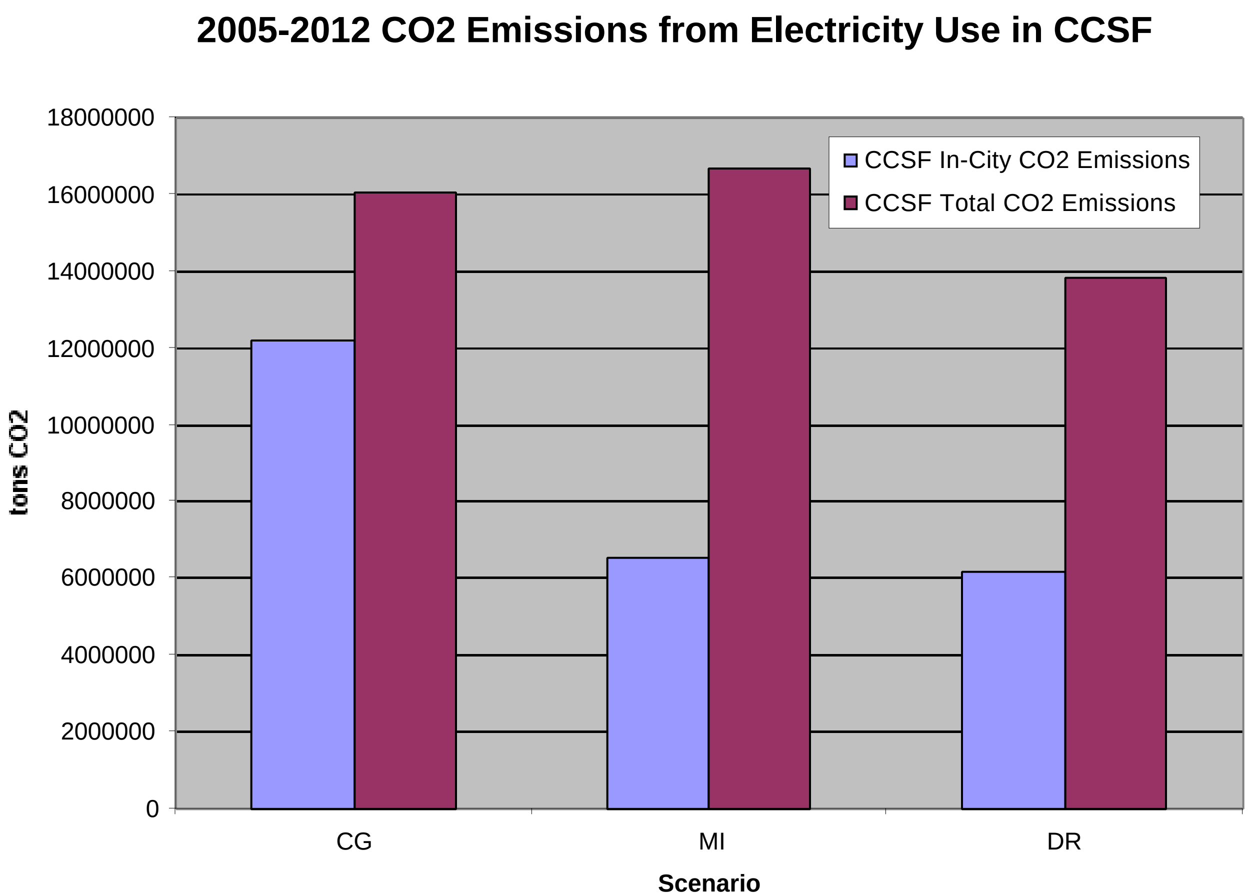

Figure 18. CO2 Emissions Caused by Electricity Usage in CCSF

None of the scenarios is clearly superior in terms of NOx emissions. The CG scenario (Figure 19) has the advantage of a large state-of-the-art CCGT plant that emits far less NOx per MWh than other fossil fuel-fired combustion technologies. The only disadvantage in this scenario is that a relatively large share of total NOx emissions occur in the City itself.

Moreover, all these emissions, and those of other pollutants as well, continued to be concentrated in the southeast part of the City. Thus, while this scenario does not address the environmental equity issue, the large reduction in the total level of emissions results in an improvement in air quality everywhere in the City and its neighboring communities.

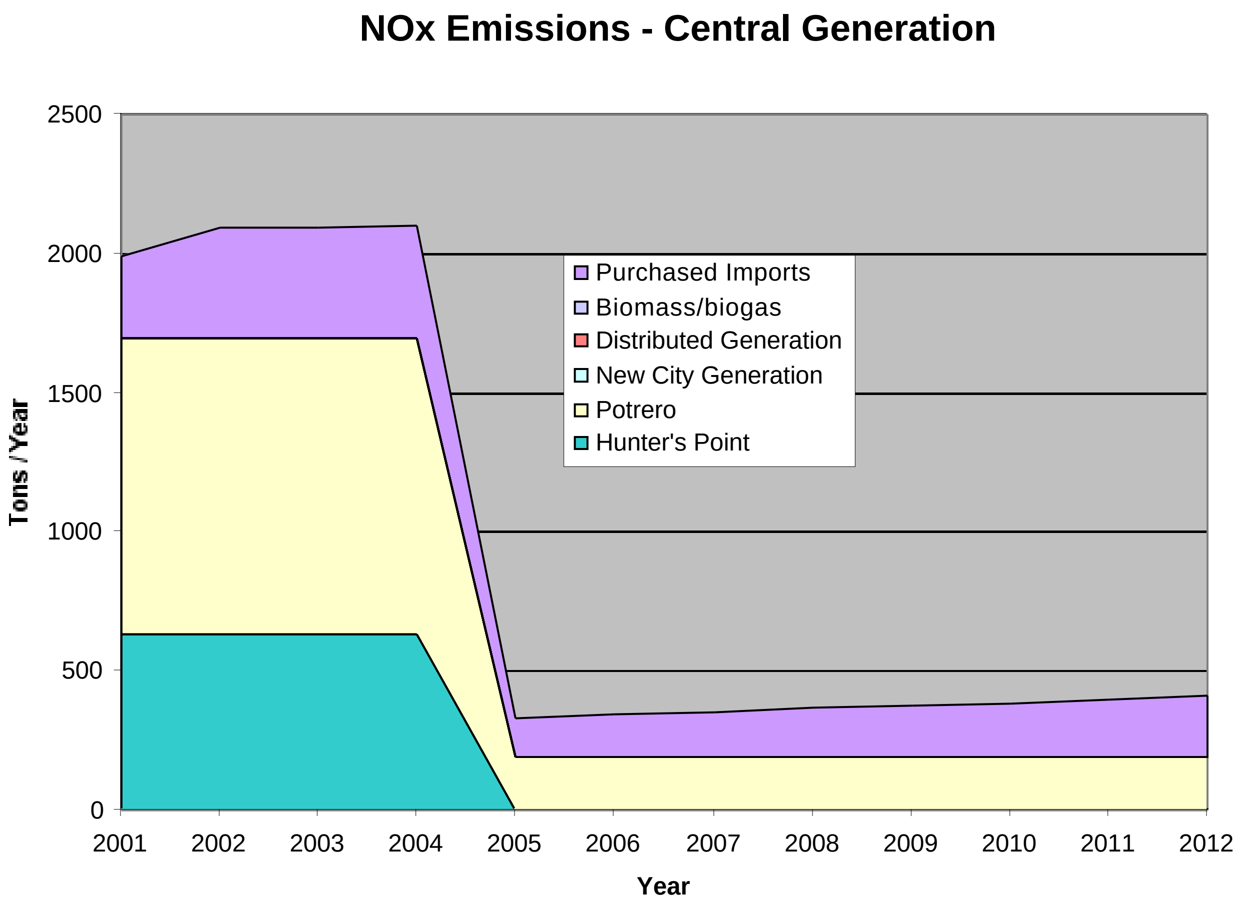

Figure 19. NOx Emissions – Central Generation Scenario

While the MI scenario emits more total NOx, this scenario still reduces emissions by more than 70% as soon as the Hunter's Point plant is closed (Figure 20). In this scenario, however, the plant remains open for an additional year compared to the other scenarios. This is because we do not expect the Jefferson-Martin transmission line to be in service until 2006. Because more power is imported, the MI scenario has the lowest in-City emissions of the three scenarios, although the remaining emissions are still concentrated at the Potrero plant.

Under DR, total NOx emissions are lower than in MI but slightly higher than in CG (Figure 21). In-City emissions are almost as low as those in MI (Figure 22). Unlike in the other two scenarios, under DR the NOx (and other pollutant) emissions, which are greatly reduced, do not continue to be concentrated in the southeast part of the City. Because of the increased use of distributed generation, the small amount of emissions in this scenario is likely to be more evenly distributed throughout the City. Because the absolute level of emissions is very low, the small increase in some areas should not create significant problems. Meanwhile environmental equity is improved significantly in this scenario.

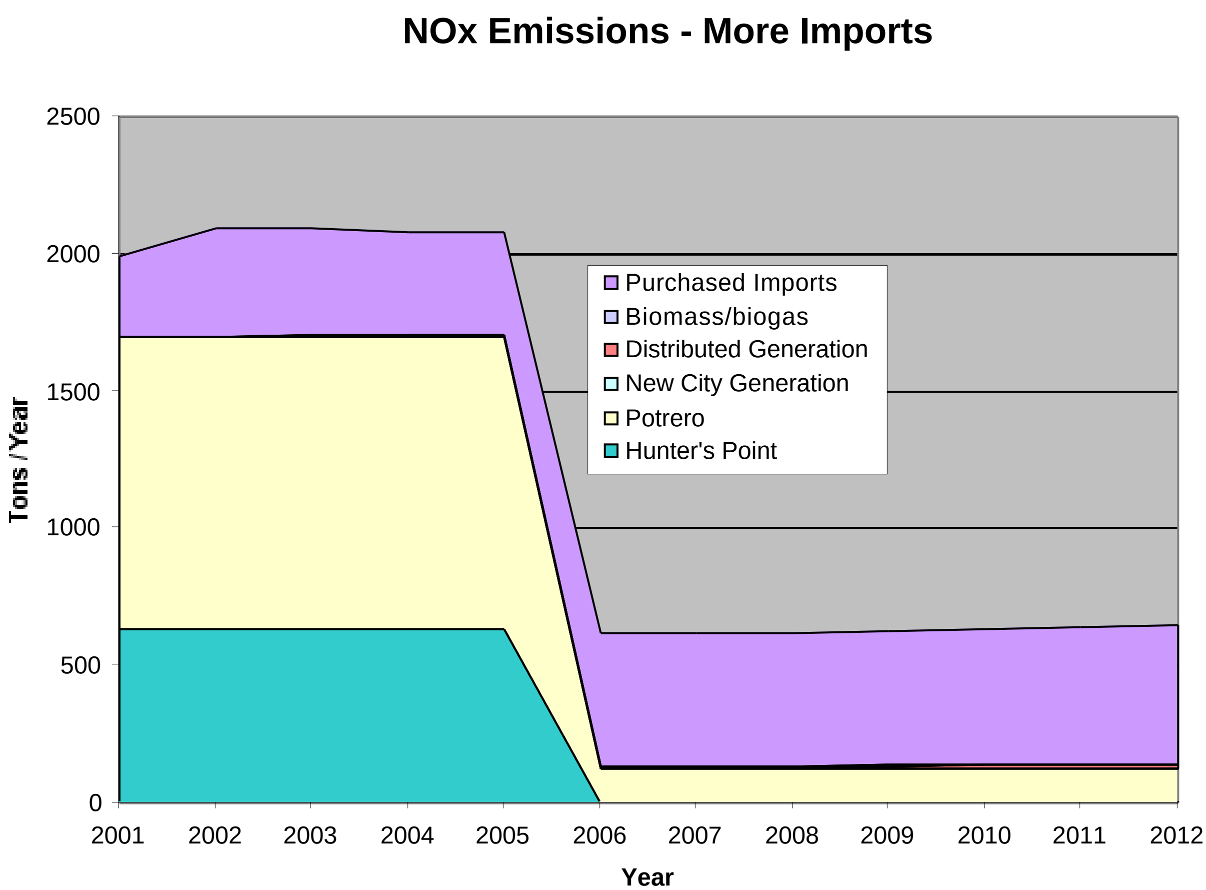

Figure 20. NOx Emissions – More Imports Scenario

To summarize the scenario results in terms of environmental impacts, all the scenarios result in emission reductions, especially NOx. While the CG scenario appears to have the lowest level of total NOx emissions, the MI and DR scenarios have lower emission levels within the City itself, which is important in terms of local health impacts (see Figure 22).

The DR scenario is the only one of the three scenarios that reduces CO_2 emissions significantly, and it appears that this scenario would be close to complying with the Mayor's goal of 20% reductions between 1990 and 2012. Regarding NOx emissions, this scenario provides an additional benefit in terms of environmental equity by distributing the very low level of emissions more evenly throughout the City.

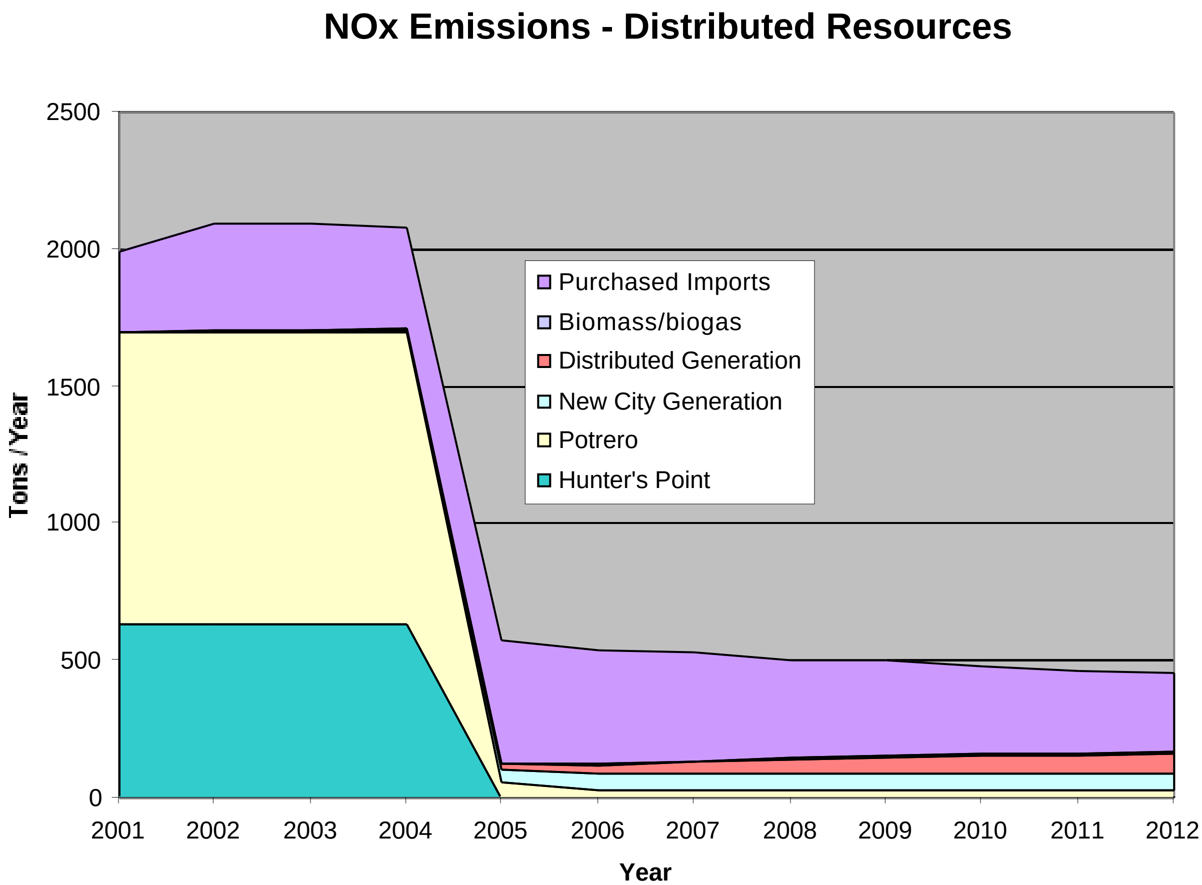

Figure 21. NOx Emissions – Distributed Resources Scenario

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 scenarios and evaluate their relative success in keeping dollars in the local economy.

First, we discuss each of the technologies in the various scenarios 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 evaluate the scenarios to determine if any are more successful in keeping dollars in the local economy.

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, combined-cycle plants, 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.

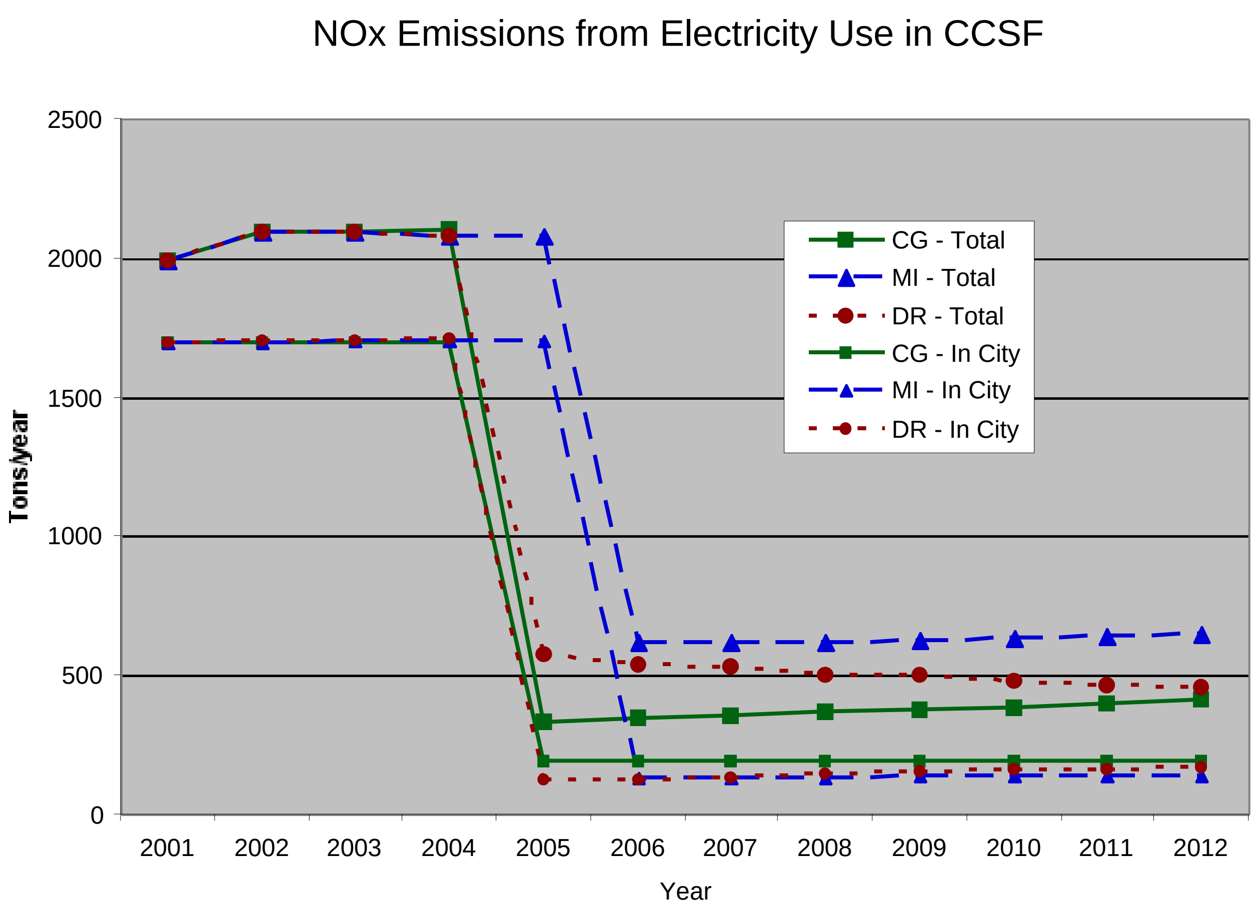

Figure 22. In-City and Total NOx Emissions Caused by Electricity Usage in CCSF

Solar technologies also embody a high degree of intellectual property. However, because two leading companies in solar technologies are in the Bay Area, more of the costs associated with this technology are local. Energy efficient equipment costs are often only slightly more expensive than the equipment being replaced. Therefore, a greater percentage of the costs are associated with local labor. Similarly, peak load management systems are available locally and their deployment requires local labor (see Table 8).

Considering the total costs of the scenarios on a present-value basis, the annual operating costs of the scenarios are larger than the capital costs. Therefore, the degree to which annual operating costs remain local is a driving factor in whether the overall technology costs stay local. 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. Local funds are not leaving the area pay for fuel supplies.

Table 8. 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
New Potrero CCGT					X
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		

In the case of both Hetch Hetchy case and wind farms, there are 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, combined-cycle plants, and distributed generation (cogeneration, microturbines, fuel cells), all require large annual costs for fuel purchases. Because fuel costs largely exit the local economy and the remaining annual costs are split between local labor and external equipment sales, these technologies keep a relatively small fraction of their total costs in the local economy (see Table 9).

Table 9. 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
New Potrero CCGT					X
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 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.

Thus, the success with which a scenario keeps dollars in the local economy depends on the technologies employed in that scenario. The CG scenario relies primarily on central fossil fuel generation. The use of a mature technology and the large power plant scale keep the capital costs per kW relatively low, and the plant's high efficiency keeps the fuel usage moderate. However, both the capital costs and the annual operating costs are mostly external, and a very small fraction of the costs remains in the local economy.

The MI scenario uses increased transmission capacity, greater imports, and moderate efficiency improvements to meet electricity demand. This strategy has lower capital costs but somewhat increased operating costs than the CG scenario. No large generating plant is built. However, the Potrero unit #3 is upgraded, and there is a significant investment in the transmission system. MI uses more of the technologies that keep the costs local, including the transmission project, and overall a greater, albeit still small, share of the costs remain local.

The DR scenario relies on a broad array of new City-owned generation (fossil fuel, wind, improved hydro), distributed generation (microturbines, fuel cells, and cogeneration), biomass, solar, and energy efficiency to meet San Francisco's electricity service needs. DR has higher capital costs than the other scenarios because the capital costs of the technologies used are higher than those of a central power plant or transmission expansion. For all of the technologies used except solar and energy efficiency, capital costs flow mostly out of the local economy. Annual operating costs similarly are mostly fuel and similarly flow outward. Solar and energy efficiency are embraced in this scenario, increasing both the capital and annual operating costs recycled into the local economy. Overall the percentage of costs remaining local is similar to the MI scenario

General Conclusions from the Scenarios

This preliminary scenario analysis of electricity futures for San Francisco is based on a limited number of alternative strategies and an approximate analysis of the cost, performance and emissions of the various technologies. Thus, the precision of the quantitative results should not be exaggerated. That said, we can offer the following general observations, which we believe are sufficiently robust that they are likely to be verified by more detailed analysis, which we highly recommend that the City undertakes.

- There are a variety of energy technologies and resource strategies that can satisfy San Francisco's need for electricity services over the next ten years.

- These strategies can emphasize central generation, additional transmission of imported power, energy efficiency and distributed generation, or a combination of these options.

- All of these strategies can provide sufficient electric energy resources and adequate reserve margins to ensure reliable service and allow the closing of the Hunter's Point plant.
- The City can produce clean, inexpensive power at Hetch Hechy and Alameda County wind farms, but only transmission capacity and in-City generation contribute to service reliability.
- All of the strategies can meet San Francisco's growing demand for electricity services without an increase in the average cost per kWh produced or saved.
- All of the strategies are susceptible to increases in natural gas prices, such that a 50% increase in gas prices would increase the average cost per kWh by about 20%.
- The central generation strategy appears to be the least expensive, if concerns regarding the potential exercise of market power by the dominant generation owner can be addressed.
- Low-cost, tax exempt municipal bond financing provided by Propositions B and H can reduce the cost of strategies that depend on renewable and distributed generation sources.
- Distribution costs were not considered here, but should be analyzed in detail to identify where and when targeted DG and DSM could provide cost savings in the distribution system.
- The strategy emphasizing transmission of imported power may be vulnerable to reliability problems due to a possible lack of in-City generation (less than 40% of peak demand).
- All of the strategies reduce local emissions by 70-80% compared to the present situation, but a central generation strategy produces more emissions in the City than the other strategies.
- CO_2 emissions are reduced significantly only with a strategy emphasizing energy efficiency and distributed generation, which comes close to meeting the Mayor's 20% reduction goal.
- A strategy that emphasizes energy efficiency and distributed generation can provide several difficult-to-quantify benefits, such as local economic development and environmental equity.
- Additional scenarios, with other combinations of strategies, might be superior to those analyzed here, for example additional transmission combined with aggressive efficiency.
- More detailed analysis is needed to guide the formulation of a full Energy Resource Investment Strategy and implementation plan.