2010
INTEGRATED
RESOURCE PLAN

Imperial Irrigation District

Resource Planning

Imperial Irrigation District

Protecting the flow of progress.

Imperial Irrigation District

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CHAPTER 1: EXECUTIVE SUMMARY

INTRODUCTION

The Imperial Irrigation District (District) must plan to meet new challenges ranging from acquiring cost-effective resources to meet retail load requirements, adapting to new renewable energy portfolio standards, reducing greenhouse gas emissions and expanding its transmission system to meet retail and export needs. These challenges must be met while keeping energy costs affordable for retail customers.

The District must adapt to increased regulatory pressure to become an environmentally friendly utility that increases the efficiency of energy use, both by itself and its customers.

The District has an enviable position as a center of renewable energy resources. This requires that the District work with a number of utilities and regional entities to develop transmission resources and renewable resources for the rest of the state. Without the renewable resources within the District's service territory, primarily geothermal resources, it is unlikely that California can meet its adopted renewable resource targets and greenhouse gas emission reduction goals without significant rate impacts on the State's consumers.

GOALS OF THE DISTRICT

This 2010 Integrated Resource Plan (IRP) attempts to merge the competing goals and objectives of the District's Board of Directors with the regulatory structure imposed by County, State and Federal regulations. A utility could attempt to become the least-cost utility or the greenest utility, recognizing green energy is currently more expensive than traditional fossil fueled resources. A utility could strive for long-term price stability, which might increase costs in the short-term.

This IRP attempts to meet the following general resource planning goals:

COST AND OPERATION GOALS

- Provide reliable energy to the District's ratepayers;
- Maintain long-term, stable energy prices by implementing a comprehensive energy hedging program and acquiring new cost-effective resources;
- Maintain the District's current status as a balancing authority;
- Optimize the operation of system resources;
- Continue to own and operate all major transmission lines within the District's service territory.

Efficiency Goals

- Implement energy efficiency programs necessary to reduce load by at least 5 percent by 2015 with a 10 percent load reduction goal by 2020.

Regulatory Goals

- Meet or exceed all state and federal planning criteria for renewable resources with a goal of generating 20 percent of energy requirements from renewable sources renewable energy by 2012, 23 percent by 2014, 26 percent by 2017 and at least 33 percent by 2020;

- Reduce greenhouse gas (GHG) emissions by at least 35 percent by 2020 from in comparison to 2009 levels to minimize the cost of purchasing emission allowance credits in the marketplace.

Regional Development Goals

- Encourage local economic development by developing new generation resources within the District's service territory whenever possible.

All of these goals are difficult to achieve simultaneously. As the District adds more renewable energy sources into its resource mix, total power supply costs will likely increase. Reducing GHG may require increasing energy costs as "green[1] energy is added to the resource mix and existing thermal generation is replaced with more efficient, and costly, generation.

The 2009 IRP attempts to balance the different goals of the District, but it may not be possible to achieve all the goals within the identified timeframes without incurring additional costs.

Forecasted Economic Activity

Between 2000 and 2005, the District experienced load growth of almost 4 percent annually. This is a high load growth for electric utilities and almost twice the average growth rate of other utilities in California. However, beginning with the housing slowdown in 2005, Imperial County's growth rate began to slow and load growth in 2007, 2008 and 2009 was essentially zero. The District is not expected to show any significant increases in electricity demand in 2009 and 2010 due to the impacts of the current recession.

It will not be until 2011 that the District is expected to begin showing any significant load growth as the U.S. begins recovering from the current severe economic recession.

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[1] Green energy is used to describe energy produced from renewable or non-greenhouse gas producing methods as opposed to "brown" energy which is produced using traditional fossil fuel generation.

Energy Requirements Forecast

Residential energy consumption is expected to decline slightly in 2009 compared to 2008 before beginning to increase slightly in 2010. The forecasted residential seasonal consumption pattern matches the seasonal use of energy for air conditioning loads that is normal in a hot desert climate.

Commercial energy use (including both large and small commercial customers) is also forecasted to remain flat or decline slightly in 2009 before beginning to increase in 2010. Commercial use also exhibits the same seasonality as residential and other customer classes.

The forecast result show that the District's energy requirements will decline in 2009 and 2010 from 2008 levels, then begin a slow recovery through 2011 before growing at a steady rate although less than the District's historic growth levels.

Demand Forecasts

Forecasting monthly peak demand is more difficult that forecasting energy requirements. Each hourly peak demand is affected by a variety of events, such as temperature and non-predictable events such as when heavy equipment is turned on and off and individual customers decide to use energy consuming equipment.

The primary determinant of actual and potential peak demand growth is new customer growth. In the District's service territory, temperature, particularly when temperature exceeds 115 degrees for three or four consecutive days (a heat storm) determines when the potential load becomes actual loads. New customers add potential air conditioning load as they install new air conditioners in their residences and businesses. Until high temperatures result in increased air conditioning use, the potential load is not felt on the system. This is one reason that IID's peak load often remains static for several years before jumping four to six percent during a heat storm.

Energy Efficiency Programs

The District is implementing an aggressive energy efficiency program with the goal of reducing peak demand by up to 50 MW within five years.

Energy efficiency programs can be classified as either conservation programs or demand-side management programs. Conservation programs attempt to reduce the total amount of energy required by consumers with no change in how people use energy such as replacing inefficient air conditioning units with more efficient units. Demand-side management programs attempt to change the timing of energy use, such as persuading people to use their appliances during low load periods of the day that changes the timing of energy use but does not affect the total amount of energy used.

The District's programs will target air conditioning, both repair and maintenance of existing residential and commercial air conditioning units, lighting and equipment efficiency. In addition, a new residential and small commercial customer thermal energy storage project, in conjunction with the Southern California Public Power Authority (SCPPA) could reduce peak demand by almost 10 MW.

The District has also implemented a new interruptible load program that will be offered to major industrial/commercial customers. This program pays customers to either drop load or operate onsite generators during periods of high demand that threaten the reliability of the District's system. The District hopes to acquire 30-40 MW from this program in 2010.

State regulations now require the District to verify the reported savings from energy efficiency programs. In 2009, the District will begin a new verification program showing the cost efficiency of each of the District's programs. The verification programs must be done by a third-party to demonstrate that the reported program savings are, in fact, being realized and that the District's offered programs are meeting minimum cost-benefit levels.

Legislative and Regulatory Changes

There have been a number of new state and federal laws that have impacted the way that the District chooses to acquire resources. In addition, the start of the *California Independent System Operator's* (CAISO's) *Market Re-Design and Technology Update* marketplace (MRTU) has placed a number of restrictions (or potential additional costs) on the ability of the District to import energy from the north and west.

Perhaps the important legislative changes deal with renewable energy and greenhouse gas emissions. At the State level, this includes AB 32, SB 1368, SB 2120, SB 1078 and SB 14.

AB 32 of the Global Warming Solutions Act and Governor Schwarzenegger's Executive Order S-14-08 directs all state entities, including irrigation districts, to achieve at least 33 percent renewable energy by 2020. AB 32 requires the California State Air Resources Board (CARB) to establish a "cap and trade" emissions control mechanism by 2012.

SB 1368 requires all long-term (greater than five year) baseload power purchase agreements to conform to new greenhouse limits. It also prohibits California load-serving entities from entering into new long-term contracts for coal or extending existing contracts more than once for less than five years. Finally, it requires new renewable generation to be certified by the California Energy Commission (CEC) prior to contract execution.

SB 2120 first established the 20 percent renewable standard by 2010. The District is not directly bound by the 2010 target of 20 percent although the District's Board of Directors voluntarily agreed to meet this goal in 2007 subject to rate impact considerations.

SB 1078 established the CEC as the certifying agency for renewable resources and required the CEC to establish a tracking mechanism for renewable energy credits to insure that renewable energy output is counted only once for RPS standards. As a result, the CEC established the *Western Region Renewable Electricity Information System*, or WREGIS, in conjunction with other western states. The District is required to register all renewable resources that it owns or constructs, track the net output from each of the certified resources and report it to WREGIS. For power purchase agreements, the generator owner is required to provide the necessary data to WREGIS to verify that sales to the District are certified as renewable resources.

A bill that was vetoed by the Governor, SB 14 (2009), stands out as a special piece of legislation. SB 14 proposed raising the 2020 RPS obligation to 33 percent for all load-serving entities in California. However, SB 14 also attempted to redefine where renewable resources must be located to count as a renewable resource. SB 14 would only count new renewable resources located within California towards the RPS standard.

SB 14 would have resulted in increased pressure on the Imperial Valley to develop its geothermal and solar resources to help the rest of the State meet the 2020 RPS standards.

Governor Schwarzenegger opposed to the "California only" component of SB 14 that requires utilities to acquire renewable resources only from California generation. The Governor has vetoed the bill and has issued an executive order implementing many of the bills goals without the "California only" requirement.

The importance of SB 14 is that, even while vetoed, it still establishes the future direction that California's renewable energy policies and greenhouse gas emission reduction programs are proceeding. The State legislature and the Governor are still negotiating about how to codify issues addressed in the Governor's Executive Order S-14-08 setting a renewable portfolio goal of 33 percent by 2020.

Federal Legislation

While it has not yet been passed by either the House of Representatives or the Senate, the *Waxman – Merkley Renewable Energy and Security Act* (Waxman) appears to summarize the Obama Administration's approach to energy and the environment.

The bill has three major components. First, it requires a minimum of 15 percent of retail sales be met through certified renewable energy by 2020. Second, it requires load serving entities to meet at least five percent of its retail load through energy efficiency programs. Finally, it establishes a greenhouse gas cap-and-trade program.

Whether or not the Waxman bill will be passed and how, if necessary, the federal cap-and-trade program would be reconciled with the California cap-and-trade program is unknown.

The most important issue with the Waxman bill is that it shows how the Washington political climate is changing and that the control of greenhouse gases has become a central issue in energy and environmental legislation.

A competing, and more restrictive bill, to Waxman-Markley is the Kerry-Boxer bill "Clean Energy Jobs and American Power Act." The Kerry-Boxer bill recognizes natural gas as a bridge fuel along with conservation technologies and attempts to reduce US dependence on coal by 2020 by essentially taxing carbon emissions at a high rate. The Kerry-Boxer bill was only introduced in September 2009 so many details are unknown. However, the biggest announced change is that unlike the Waxman bill where carbon emissions are capped but firms can trade emission credits, the Kerry-Boxer bill caps carbon emissions with no trading, requiring firms to reduce their emissions on an annual basis by around 5 percent per year.

Summary of Legislative Requirements

The legislative efforts at the state and federal levels are intended to encourage utilities to increase the procurement of renewable resources, reduce GHG emissions and significantly increase energy efficiency efforts.

Many of the bills will not take full effect for two or three years into the future and then only after study and development of new regulations by different regulatory bodies.

The District participates in many of the different forums and proceedings to insure understanding and agreement with proposed legislation. As the state and federal energy and environmental policies evolve over the next two years, the District must insure that its resources, including both generation and transmission, can accommodate the proposed new laws and regulations with minimal impacts on its ratepayers.

Transmission Resources

The District's long-term transmission planning efforts are primarily centered on meeting retail load obligations. In addition, the District must also provide transmission services under its *Open Access Transmission Initiative* (OATI) to generators selling energy to entities outside of the District's control area.

The District's current long-term transmission plan meets the needs of its retail customers. The District is also working on upgrades to its major south-north transmission lines to increase near-term export capacity by approximately 1,200 MW by 2014. However, this planned transmission upgrade is now totally subscribed and additional south-north transmission capacity will be required to export planned generation from the Imperial County by 2015 or 2016.

It is almost a foregone conclusion that a major new transmission line will be constructed into the Imperial Valley with a number of new 500 kV transmission lines proposed by private and public entities. If the District does not develop this new line itself, the District will work with the various project sponsors to develop a line that maximizes the benefits to the District and its ratepayers. The District will oppose any new lines that threatens its balancing authority rights or which could result in stranding the District's investment in transmission resources.

Currently the District is involved in informal, non-binding talks with a number of different entities on possible new transmission lines, generally coming from the Yuma area to Imperial Valley substation in El Centro and then north through Imperial Valley to Devers substation in the Palm Springs area. But there is no development or planning agreements with any of these entities that would like to build the new line.

How to meet this additional demand for south-north transmission is one of the District's most critical near-term tasks. Choosing its partners and the management and financial structure of a major new transmission line will help the District meet its transmission obligations and protect the District's Balancing Authority rights and protect the District's existing transmission wheeling revenues from encroachment from other entities.

Base Case Power Supply Plan

The planning process has resulted in a proposed generation plan that meets renewable portfolio standards and greenhouse gas emission reduction requirements, while providing a high degree of price certainty for the period 2010 through 2012.

A basic summary of the proposed resource plan includes adding:

- A new 145 MW combined cycle generation facility at the existing El Centro Steam Plant Unit 3 by 2012;
- Entering into a power purchase agreement for 50 MW of geothermal generation for delivery by 2013;
- Entering into a power purchase agreement for 20 MW of solar thermal generation by 2012;
- Entering into a power purchase agreement for 17 MW of geothermal generation by 2014 with other Southern California Public Power Agency members.

These planned resource additions are in addition to the District's power purchase agreement with the Greenhunter Mesquite generation facility that adds 18 MW of bio-mass generation in 2011 to the District's resource mix and the Ice Bear Thermal Energy Storage project with 10 MW of load shifting and interruptible loads.

With these new resources, the District will generate almost 25 percent of its annual energy requirements from renewable energy sources by 2013/2014 while keeping total power supply costs relatively stable for the next three years.

A key to the District's power planning process is to minimize the impact of changes in natural gas costs. Currently, the District attempts to establish hedges two to three years into the future. In the near term, the District would like to increase its hedging activities to a five year term. A longer-term hedging strategy will allow the District to achieve price stability for a longer period in the future.

It is also useful to recognize that, from a rate perspective, it is not the total power supply cost that is important but the average cost per MWh. The proposed generation mix presented in this IRP keeps average energy costs rising at a relatively low rate over the next three years.

Summary and Recommendations

Based upon the analysis and studies prepared for this report, the following major recommendations are presented:

- The District should repower Unit 3 of the El Centro Generating Station. The repowering, with an expected cost of around $250,000,000 will provide additional efficient generation and additional ancillary services necessary as more intermittent resources are developed in the Imperial Valley;

- The District should enter into power supply agreements for an additional 50 MW of geothermal generation and 20 MW of solar generation with in-service dates by 2014 to help meet RPS standards and reduce GHG emissions. Renewable generation will also help reduce the price volatility of the District's power supply costs, although the additional renewable resources will be at a higher cost than traditional "dirty" resources;

- Conservation and demand-side management activities should supply around 50 MW to reduce the District's need for resources that are expected to be used for less than 500 hours per year. The Ice Bear Thermal Energy Storage project and interruptible rates are a the first step towards achieving the 50 MW of demand-side management requirements;

- The District should continue planning to meet GHG emission reduction legislation. Proposed additions to the District's resource mix will help reduce GHG emissions from the District's old, inefficient internal resources but additional reductions will be required to avoid having to purchase emission credits in the future at a potentially high cost;

- The District should evaluate its continued participation in San Juan Generating Station in light of increased costs of GHG and the high level of GHG emissions from this facility;
- The District should expand its gas and power hedging programs from the current three years to five years into the future to provide greater power supply cost stability;
- Completing the Path 42 transmission upgrades should be considered the first priority in transmission planning. This project opens the Imperial County for renewable energy development;
- After Path 42, a new 500 kV line from south-to-north will be developed in the District's service territory. The District should identify which path it prefers and who, if anyone, it will partner with as quickly as possible to have the new line available by 2016;
- The District is not taking advantage of surplus capacity during the November through March time period. The District should develop and implement procedures for bidding and selling surplus capacity into the CAISO market during the winter months;
- The District should anticipate power costs from marketers will rise as GHG emission costs are included in the wholesale market price. The District can control long-term more effectively by developing its own generation resources with low GHG emissions either by upgrading generation resources within its service territory or entering into new long-term contracts for renewable resources or a combination of both.

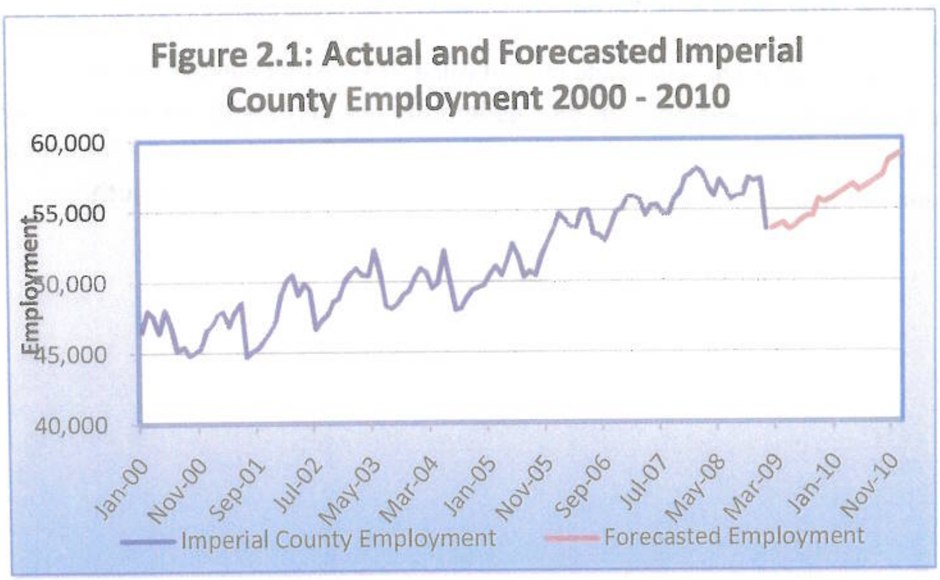
CHAPTER 2: FORECAST OF DEMAND AND ENERGY REQUIREMENTS

ECONOMIC FORECAST

The District has prepared a forecast of county employment using California employment forecasts.[2] The Imperial County employment forecast is used as the primary explanatory variable for residential and commercial energy use within the District's service territory.

The Imperial County employment forecast shows that 2009 employment will decline by about 4,300 jobs in 2009 as compared to 2008. The County economy will begin recovering in the first quarter of 2010 as the State economy begins to improve but employment growth will lag two to three quarters. Thus, it may not be until 2011 that the regional economy begins to see any significant employment growth in comparison to 2009 levels.

Figure 2.1 summarizes the employment forecast.



California's economy is expected to have reached its lowest level in the second quarter of 2009. The State economy should then level off for two quarters before beginning to improve in early 2010.

Even by 2010, Imperial County is unlikely to match the economic growth rate of the California economy. There are no existing employment growth industries that would help Imperial County

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[2] Sacramento Forecasting Project at California State University, Sacramento

grow its economy other than a return to pre-2005 construction levels and renewable energy. Government and agriculture will not suddenly expand employment to historic levels and, in fact, may decline as the long-term revenue impacts from declining housing values impact government revenues. The service sector may rebound slightly as personal income rises though not substantially in 2010.

In effect, the high proportion of Government and Agricultural jobs that helped cushion the regional impacts of the national economic downturn will result in slower regional growth when the state and federal economies improve.

The net result is that a return of a viable housing market will help pull Imperial County out of its current employment slump but may not result in any significant long-term employment growth.

An interesting way to help jump-start the Imperial County job market would be to encourage the development of renewable energy projects. Generally, a new construction project creates around 6.5 jobs per $1,000,000 construction cost and an additional 2.5 jobs in secondary income effects. Thus, a $250,000,000 construction project could create as many as 2,075 jobs in Imperial County. As importantly, the jobs created in the construction phase match the employment characteristics of the regions unemployed individuals. That is, the newly created jobs will go to existing residents and workers rather than imported employees.

Forecast of Energy Requirements

Once the Imperial Valley employment forecast was developed, the employment forecast was used to forecast commercial and residential energy requirements for the District.

The employment forecast captures both household growth in Imperial and Coachella Valley and income growth. As employment and income increases, electric demand will also increase.

One of the biggest problems with forecasting monthly energy sales is relating billing data to consumption. A typical electrical bill captures energy use during the past 30 days. So energy sales data in July will actually reflect energy use from both June and July. For example, a bill prepared on July 10^{th} will have twenty days of June consumption data and ten days of July consumption.

As an example, consider a hot August followed by a cool September. Energy use would be high in August and low in September. But if unadjusted billing data were used, the high August use would be billed in September and the relationship between hot weather (hence air conditioning use) and energy use would not show in the analysis.

In order to try to match actual consumption by class, the billing data must be adjusted to match actual consumption, not billing data. Otherwise, the estimated statistical relationship between income, weather and energy use will misrepresent the true relationship.

Temperature

The District's high use periods are the hot summer months when high temperatures lead to the high use of air conditioners. Summer temperatures vary from the high 90 degree to the low 120 degree range.

Temperature is the major reason for changes in monthly energy use in the forecasting model. Degree Days Cooling (DDC), a measure of the average daily temperature was used as the major explanatory variable, along with a weighted average of prior days DDC to attempt to measure temperature build up.

Forecasts of Sector Energy Use

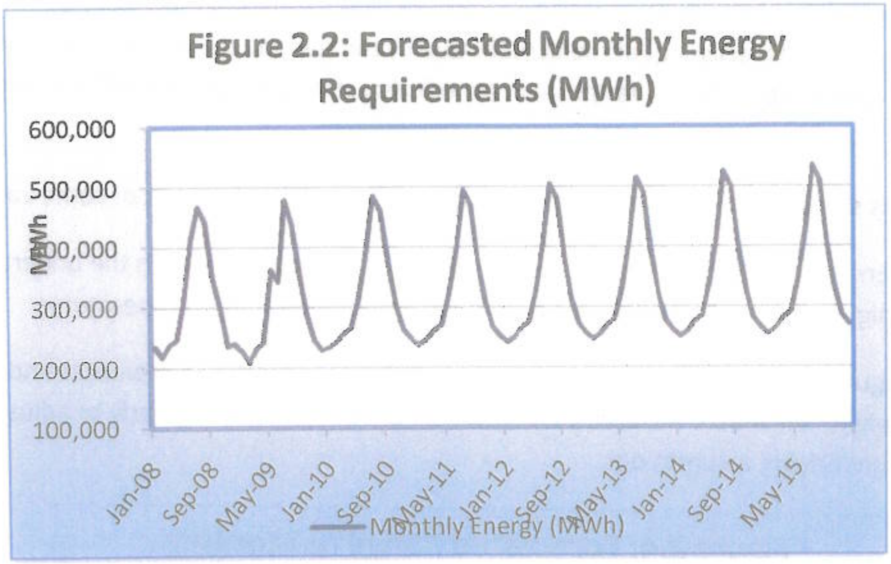
In addition to a forecast of monthly energy use for the District, forecasts of residential and commercial/industrial energy use were prepared. These sector forecasts were used to validate the overall forecast of monthly energy requirements.

Data is available for residential, commercial and industrial use along with several minor breakdowns of use. However, due to changes in the definition of commercial and industrial use over time, the statistical analysis performed better at a lower level of granularity.

Energy Forecast

The long-term monthly energy use forecast shows that energy use in 2009 and 2010 is basically flat relative to 2008 energy use. It is not until 2011 when the California economy begins to recover from the current economic recession that both economic and retail energy use begins to recover from current levels. But, even with the current economic conditions, the District's energy use still shows a small energy increase of around 0.7 percent (from 2008 through 2012) unlike many other utilities that are seeing declines of 3 to 4 percent (or more) in annual energy use.

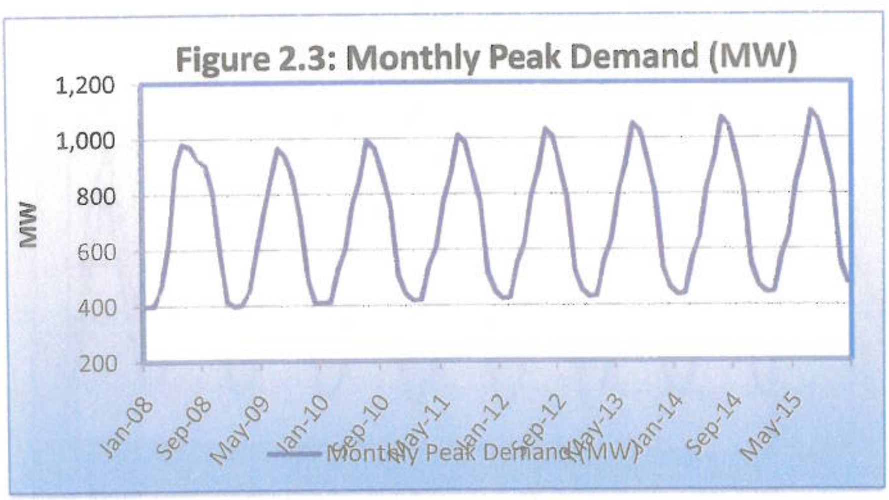
Figure 2.2 presents the long-term forecast of monthly energy use.



Monthly Peak Demand Forecast

Forecasting monthly peak demand is difficult due to the short time frame of the forecast. A peak demand forecast is essentially a forecast of instantaneous conditions while the energy forecast is the average of all the hourly demands during the month. As such, demand forecasts have a high variance.

The District's demand forecast uses the average of historic monthly load factors to calculate demand. The following figure presents the long-term monthly peak demand forecast. Notice that summer peak demand increases at a higher rate than winter peak demands.



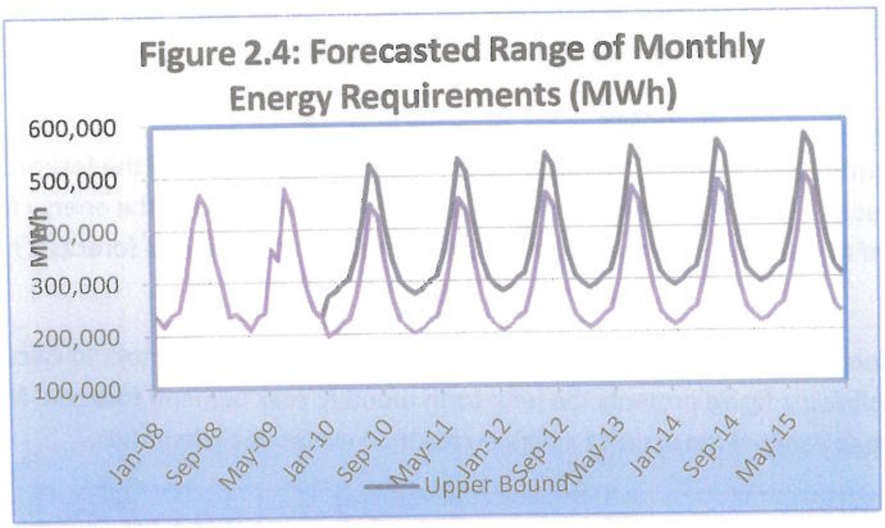
Statistical Ranges for Demand and Energy Forecasts

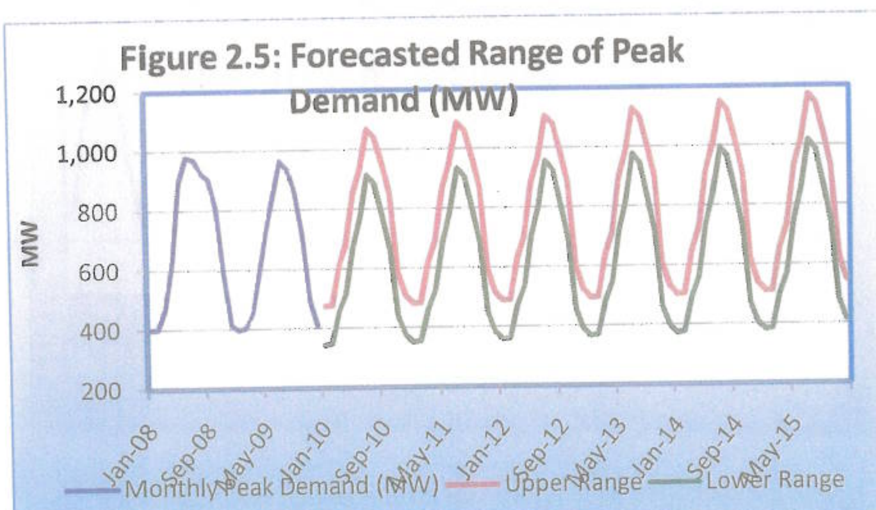
Every point forecast of long-term energy and demand requirements is wrong. Only by coincidence is does the forecast equal the actual value of the dependent variable. Yet, forecasts of demand and energy do identify a range where the forecast variable is likely to be at any particular time.

That is, forecasts should be thought of as a range rather than a point forecast of some value.

Over time, the error in any forecast increases due to unanticipated changes in the underlying values such as higher than anticipated growth or higher than forecasted temperatures.

The following figures illustrate the expected ranges that future energy requirements and demand are likely to fall within. However, forecasts should be updated regularly to adjust for changes in the underlying assumptions.





Chapter 3: The District's Existing Generation Resources

Introduction

In 2009, the District's peak demand forecast was slightly under 1,000 MW. However, as a balancing authority, the District is required to have generation resources providing spinning reserves, non-spinning reserves, operating reserves and planning reserves, totaling about 15 percent of load. Thus, the District required generation resources plus purchases equal to almost 1,150 MW for the peak summer months.

The District meets its annual resource requirements through a mix of the District owned generation and a number of purchase power contracts that can take the form of must-take contracts and call options.

The District's generation resources range from hydroelectric resources on the All-American Canal System to San Juan Unit 3, a coal plant in New Mexico, to the Palo Verdes Nuclear Generation Station near Phoenix and natural gas and diesel generation within or near the District's service territory.

Power purchase agreements (PPA) include fixed price, must-take contracts and options that satisfy the majority of the District's energy requirements. The District's internal gas-fired generation tends to be older, inefficient units (with a few exceptions). These units can be used to meet internal capacity requirements but generally are too inefficient and costly to operate for long periods and many have restricted hours of operation due to air quality restrictions.

Balancing Authority Obligations

The District is a Balancing Authority (BA) in the Western Electric Coordination Council (WECC). As a BA, the District has the obligation to:

- Match generation to load;
- Maintain scheduled interchanges with other Balancing Authorities;
- Maintain the frequency in real-time of the power system.

In order to meet these obligations, the District must forecast hourly retail load and know the schedules of generators selling energy to entities located in other balancing authorities. The District must have sufficient generation and power purchases to meet forecasted load plus reserves.

There are three different types of reserves, *spinning, operating and planning.*

Under normal circumstances, reserves are generally equal to around 15 percent of load. *Spinning reserves* are reserves available for immediate dispatch[3]. Spinning reserves are around 3.5 percent of total load. *Operating reserves* are generation resources that are available in ten minutes but are not synchronized with the grid, such as a quick start gas turbine. Generally, operating reserves are around 3.5 percent of total load. *Planning reserves* is generation that can be available in one hour. Planning reserves are usually 8 percent of total load.

The District is a participant in the Southwest Reserve Sharing Group (SRSG).[4] As a member of the SRSG, the District's hourly reserve obligations are reduced from approximately 35 MW of spinning reserve to around 20 MW during the summer.

Renewable resources create a special scheduling problem for the District, particularly wind and solar generation. These types of renewable resources are classified as intermittent resources. A cloud overhead or the wind stopping requires the balancing authority to make up any generation shortfall that is exported to other BA's from reserves (spinning), although the balancing authority has the right to charge the generation facility for providing back-up energy.

The District does not provide ancillary services for geothermal resources that are exporting energy into the CAISO. These generators are required to match scheduled generation to actual generation within a 2 MW band. If their generation goes to zero, the District simply cuts their schedules with the CAISO rather than replace the energy for the generator. The District does charge a generator for any energy that it supplies on the generator's behalf.

As more solar and wind generation is developed within the District's service territory, the District will have greater difficulties balancing loads and generation and the need for spinning and non-spinning reserves will increase. The District is examining the feasibility of requiring purchasers in nearby balancing authorities that are importing energy to have dynamic scheduling capabilities rather than providing any ancillary services for power scheduled for export.

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[3] Spinning reserves are generation that is synchronized with the transmission grid and can be available within ten minutes. Non-spinning reserves are not synchronized.

[4] The members of the SRSG include IID, Arizona Public Service, Dynegy. El Paso Electric Company, Farmington Electric Utility System, Entegra, Harquahala Generating Project, Nevada Power, Public Service Company of New Mexico, Southwest Transmission Cooperative, Salt River Project, Tri-State Generation and Transmission Association, Tucson Electric Power and Western Area Power Administration.

Hydroelectric Resources

The District has a number of small hydroelectric electric facilities located on the All-American Canal and near-by branches. The largest of these hydroelectric facilities is Pilot-Knob, a two-unit facility with a combined nameplate rating of 33 MW. The smallest unit is Double Weir with two units each with a rating of 0.28 MW.

The hydroelectric units have a combined rating of about 85 MW, although due to seasonal water flows, the summer capacity rating is around 32 MW of effective summer capacity.

The District's hydroelectric projects are considered green resources and energy produced from them helps satisfy the District's RPS requirements.

Annual energy production from the units is approximately 250,000 MWh although this value changes according to water availability.

Southern California Public Power Agency

The Southern California Public Power Agency (SCPPA) is a joint action agency comprised of the Cities of Los Angeles, Glendale, Burbank, Cerritos, Vernon, Pasadena, Anaheim, Riverside, Azusa, Banning and Colton and the District. The District (as an irrigation district) is the only non-municipal member of SCPPA.

SCPPA acts as a funding entity for transmission, generation and energy efficiency projects. SCPPA will issue debt for the construction of new resources and then secure this debt with take-or-pay contracts with project participants.

Joint action entities like SCPPA allow small entities the opportunity to participate in larger, cost-effective generation resources. A publicly-owned utility that is too small to buy an entire project can enter into a take-or-pay contract with SCPPA that will aggregate the needs of all its members. SCPPA will then issue debt to construct or purchase the generation resource and recover its debt service costs through take-or-pay contracts[5] with the project participants.

The District is a participant in two SCPPA projects, San Juan Generating Station, Unit 3 and Palo Verde Nuclear Generating Station but has not participated in the majority of SCPPA's projects, primarily due to geographical issues. The majority of SCPPA's members have transmission access to the north and east but the District does not have the transmission resources necessary to access many of SCPPA's projects.

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[5] A take-or-pay contract means that the participants pay the cost even if no energy is produced or they choose not to dispatch the generation project.

San Juan Generating Station

The District has an entitlement through SCPPA of 106 MW in the San Juan Generating Station (SJGS) unit 3.

The District may schedule from a minimum of 27 MW up to the maximum of 106 MW during each hour.

SJGS3's environmental equipment has recently been upgraded in an extensive equipment upgrade. PNM and other plant co-owners have invested $330 million at the 1,800-megawatt coal-fired power plant (four units of 450 MW each), 15 miles west of Farmington, to reduce emissions of sulfur dioxide, nitrous oxide, coal dust particles and mercury.

The emissions-reducing upgrade was agreed upon as a settlement to a 2002 lawsuit filed by the Sierra Club and Grand Canyon Trust following reports of more than 60,000 air quality violations at the San Juan Generating Station.

The renovations are anticipated to reduce plant emission of sulfur dioxide and particulate ash by an additional 50 percent, nitrous oxide emissions by 30 percent and mercury emissions by 90 percent.

Energy from SJGS is received at Blythe-Knob on the east side of the District's service territory. SCPPA has a displacement agreement with Tucson Electric Power to take the energy from Public Service Company of New Mexico (PNM) which delivers the power to the Western Area Power Administration at Westwing 500 kV Substation (near Palo Verde) which then delivers the power to Liberty and Pinnacle Peak substations for delivery to Blythe Substation.

Palo Verde Nuclear Generating Station

The District has a small entitlement (through SCPPA) of capacity in each of three units at the Palo Verde Nuclear Generating Station (PVNGS). The District's total (delivered) capacity is 14 MW (5 MW from each of the 3 PVNGS units less losses).

One of the greatest benefits of nuclear generation is the lack of any greenhouse gas emissions. Energy from PVNGS is expensive compared to current market prices although the reduction in greenhouse gas emissions helps the District's efforts to meet GHG emission levels.

Western Area Power Administration (Western) Parker-Davis Dam

The District has an entitlement of 32.6 MW[6] (summer) in the Parker-Davis Hydroelectric Project (Parker-Davis) in western Arizona. Energy from Parker-Davis is provided by Western at the rate of 3,679 MWh per MW of capacity per month.

Parker-Davis energy can be primarily used during the on-peak periods, although a small portion of the energy must be scheduled during the off-peak periods due to water management requirements of the Parker and Davis dams by Western.

While Parker-Davis is a hydroelectric project, it is not considered a renewable project by the State for RPS requirements. Hydroelectric projects must be less than 30 MW to qualify as renewable projects.

Parker-Davis capacity is a source of inexpensive capacity and energy. As such, the District is continually defending its allocation from claims from other eligible entities, primarily Native American tribes and the Department of Defense.

The Districts current allocation expires on January 1, 2018. Western will likely start a re-allocation of Parker-Davis' capacity in 2015 or early 2016. The District will have to make a compelling case at Western if it hopes to retain all or most of its current capacity allocation.

Yuma Axis Steam Plant

One of the District's most important units is the Yuma Axis Steam Plant in Yuma, Arizona. This steam unit has a nominal rating of 75 MW (an operational rating of 70 MW) and is used for energy and ancillary services, including regulation, on the District's system.

There is also an associated small gas-fired turbine (19.7 MW) at Yuma that is seldom used due to the poor heat rate of the unit.

Currently, APS operates the Yucca Plant under an operating agreement with the District. This operating agreement includes procuring natural gas supplies for the Yucca Plant.

The District is evaluating the feasibility of acquiring its own natural gas supplies for the Yucca Plant. APS physically provides natural gas to the Yucca Plant. APS has refused to allow the District to hedge natural gas costs using traditional physical hedges and so the District has put in place financial hedges to protect itself against spikes in natural gas costs. The feasibility of acquiring alternative gas supplies is discussed further in Chapter 10.

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[6] During the five winter months, the monthly capacity declines to 26.3 MW.

Internal Thermal Generation

The District owns 14 thermal generation facilities within its service territory. The unit names, fuel type and performance are summarized in Table 3.1.

As Table 3.1 shows, with the exception of the El Centro Generation Station, Unit 2, most of the District's thermal resources are fairly inefficient. New baseload generation has a heat rate of around 7,600 BTU/kWh or better. An exception to this is the Niland Gas Turbine units, which are peaking facilities intended to be operated during on-peak periods and which have restricted operating hours due to air quality regulations.

Table 3.1: District's Generation Resources Located Within the Service Territory

Name	Summer Operating Capacity (MW)	Fuel Type	Heat Rate (BTU's/kWh)
El Centro Generating Station, Unit 1	23	Natural gas	Indefinite Shutdown
El Centro Generating Station, Unit 2-1 and Unit 2-2 Combined Cycle	117	Natural gas	8,451
El Centro Generating Station, Unit 3	42	Natural gas	12,159
El Centro Generating Station, Unit 4	72	Natural gas	11,547
Niland Gas Turbine Unit 1	43.5	Natural gas	9,772
Niland Gas Turbine Unit 2	43.5	Natural gas	9,772
Coachella Gas Turbine, Unit 1	21	Natural gas	14,869
Coachella Gas Turbine, Unit 2	21	Natural gas	14,741
Coachella Gas Turbine, Unit 3	21	Natural gas	14,422
Coachella Gas Turbine, Unit 4	21	Natural gas	13,968
Rockwood Gas Turbine, Unit 1	21	Natural gas	13,294
Rockwood Gas Turbine, Unit 2	21	Diesel	13,294
Brawley Gas Turbine, Unit 1*	9	Diesel	19,472
Brawley Gas Turbine, Unit 2*	9	Diesel	19,472

**The Brawley Gas Turbines are expected to be retired in 2011.*

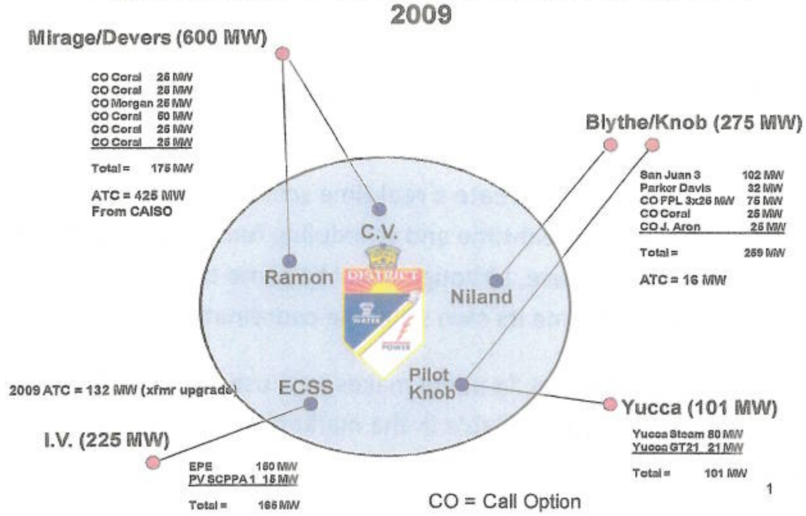
Power Purchase Agreements

Because many of the District's resources are old and inefficient, the District has relied on a number of *power purchase agreements* (PPAs) to meet much of its energy requirements. The District's existing generation resources have been counted as operating reserves.

There are a number of components that are studied prior to entering into a PPA. These include the amount of capacity required, the amount of capacity required at different hours of the day, the structure of the PPA itself, including such things as the fixed price, the energy price and how often it is expected to be used. The second is the transmission availability and cost.

The District always has to insure that transmission exists for a new PPA. Figure 3.1 identifies where the District can import energy and the approximate amount of transmission capacity available to the District:

Figure 3.1: Import Transmission Capacity Summer 2009



Legend:

I.V. = Imperial Valley Substation

ECSS = El Centro Switching Station

C.V. = Coachella Valley Substation

ATC = Available Transmission Capacity

The largest single purchase the District currently has is with El Paso Electric (EPE). This PPA, that expires on April 30, 2010, is for up to 150 MW for all hours of the year. The PPA allows the District to schedule from 25 to 150 MW.

The District also relies on a number of heat rate options for peaking capacity. A heat rate option has a fixed price that is determined by the likelihood of energy being called upon and an energy price determined by the daily spot price of natural gas. The lower the heat rate (hence the more likely the option is to be exercised) the higher the option price.

For example, a heat rate option of 7,600 BTU/kWh may have an option cost of $10.00 kW-month, while a heat rate option with a 14,000 BTU/kWh may have an option cost of only $2.00 kW-month.

The type of option depends upon the likelihood of actually exercising the option and having to pay for the associated energy. If the option is likely to be called only a few times per year for a few hours during peak periods, then the District would want to minimize the annual fixed cost. If the option were likely to be called multiple times each month, then the District would be better off paying more for the option and lowering the energy costs by reducing the option heat rate.

Spot Purchases

The District has begun aggressively purchasing energy in the short-term and hourly markets. In 2009, short-term purchases (both day ahead and real time) make up almost 14 percent of total energy requirements, compared to less than 6 percent in 2007.

The District is currently recruiting staff to create a real-time scheduling desk. Currently, Shell Energy performs most of the District's real-time and scheduling functions. The District intends to bring more of the daily functions in-house, although it will be some time before the District has the ability (and infrastructure) to become its own schedule coordinator[7].

A truism in the generation industry is that "a utility makes best use of generation by not operating it." This means that energy is available in the marketplace at a lower cost than the utility's cost of generating.

The District, with its inefficient, high cost resources, reduces power supply costs by minimizing the amount of generation that it operates. This means that market prices are lower than the cost of generation and the District can meet its retail obligations with less expensive energy. The District would prefer to meet much of its energy requirements with inexpensive, imported energy and only have enough generation online to meet its BA obligations.

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[7] A schedule coordinator is responsible for scheduling all generation and transmission resources under its operational control with the Western Energy Coordinating Council and is required to staff for 24 hours of the day and maintain greater control over transmission schedules than the District currently does.

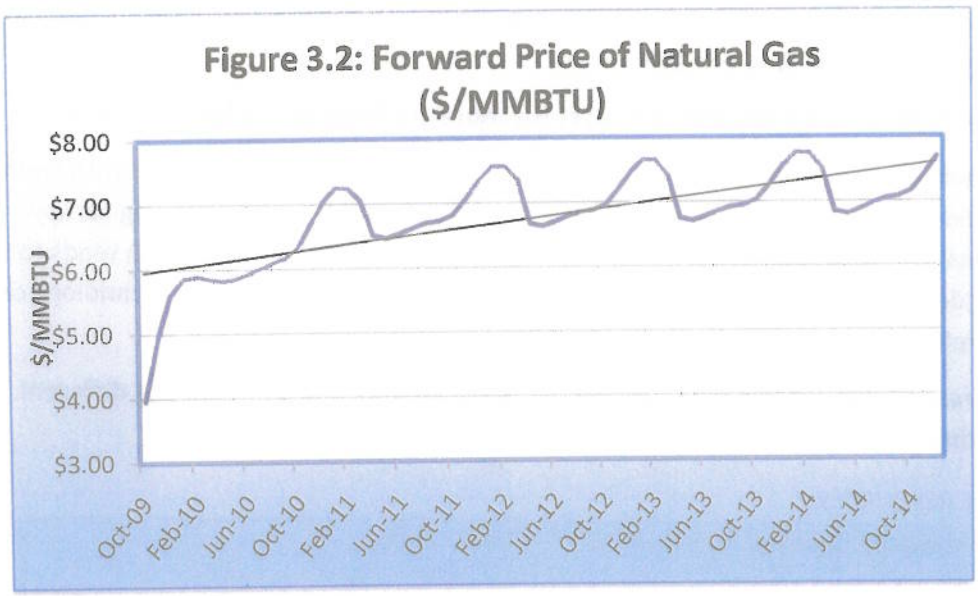
Natural Gas Prices

Natural gas purchases account for about 25 percent of the District's total power supply costs (approximately $65,000,000 in 2009) as fuel for District's natural gas-fired generation fleet. The District has begun a hedging program designed to reduce the volatility of the cost of purchasing natural gas for a rolling three-year period.

Gas prices are extremely volatile with significant swings depending upon supply-demand imbalances.

Over the past five years, natural gas prices have ranged from a monthly average high of $12.50 to a low of $4.60, although daily prices have been as low as $1.90/MMBTU[8].

Figure 3.2 presents the forward price of natural gas.



The District attempts to hedge about 70 percent of its three-year future gas requirements, enough to insure that power supply costs do not rise more than 30 percent from current levels three years from today. Hedging activities are designed to reduce the volatility of power supply costs in the near-term so that annual power supply budgets do not show significant deviations from actual costs.

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[8] Source: Energy Information Administration, Department of Energy. Regional prices have shown even greater volatility with prices in Southern California as high as $14.00/MMBTU in the spring of 2008.

Load Resource Balance

The District's existing resources and power purchase agreements are sufficient to meet the forecasted load for 2010 and 2011. By 2012 the District is short capacity to meet forecasted load requirements due to the expiration of many of the existing PPA's.

Identifying the right mix of new resources to meet the District's 2012 resource deficit is critical. The District must meet regulatory requirements, such as the RPS requirements and GHG emission levels, while attempting to minimize annual costs. An incorrect resource mix could lead to higher costs than necessary or prevent the District from meeting GHG requirements.

Renewable Resources

Unlike other areas of the state, the District has a number of geothermal, solar, wind and biomass alternatives available to meet its renewable energy requirements. Estimates of the potential renewable energy alternatives within the Imperial County range as high as 3,500 MW of financially viable renewable energy sources.

Choosing the right mix of renewable resources is a more challenging task for the District.

While geothermal resources are the most economic, they are a baseload resource with limited ability to schedule and dispatch. Solar and wind resources are only available during certain hours and may not be available when necessary (especially wind generation which tends to be unavailable during the peak hours of the day). Choosing too much of a specific technology can result in surplus energy that must be sold at a loss.

Table 3.2 presents the approximate average cost of generation from each of the different primary technologies available to the District.

Renewable Resources

Table 3.2: Estimated California Costs for RPS Eligible Energy

Technology	Average Cost ($/MWh)	Low Cost ($/MWh)	High Cost ($/MWh)
Biomass	$152	$114	$190
Geothermal	$100	$70	$130
Solar PV	$239	$192	$285
Solar Thermal	$125	$115	$200
Wind	$93	$60	$123

Averages shown are simple averages based on high and low estimated generation costs for each category. Data is from the RETI Phase 2 Final Report except for solar thermal which is based upon offers submitted to the District in RFP 693.

Greenhunter Mesquite Power Purchase Agreement (Greenhunter)

Besides its small hydroelectric generation, the District has only one significant renewable energy contract, a power purchase agreement with Greenhunter Mesquite, LLP.

The District has entered into a long-term PPA with Greenhunter for 18 MW. Greenhunter is a biomass facility (woodchips) located near the City of Imperial within the District's service territory.

When refurbished, Greenhunter is expected to generate 125,000 MWh of renewable energy annually, around 4 percent of the District's RPS obligations.

Greenhunter is expected to be online by June 2011.

Bullfrog Dairy

The District has a very small biogas contract with Bullfrog Dairy using gas from cow manure to power a small reciprocating engine. This is only a 25 kW contract with most of the energy used on-site.

Summary

Although the District has significant amounts of generation within its service territory, much of it is financially non-viable in today's power markets. The District attempts to displace internal generation with short-term purchases in the day-ahead markets and reserves the internal generation for operating reserves.

Chapter 4: Natural Gas and Electric Purchasing Alternatives

Introduction

The District has choices how to meet any future energy resource needs. It can purchase and construct physical generation, enter into a power purchase agreement or enter into an option for future power.

The District uses the same tools for purchasing natural gas as it does for electricity, with the exception of constructing physical capacity.

This section reviews some of the different alternatives available to the District. It is easier to begin with the District's options for purchasing natural gas because the natural gas price is fixed for a day or month at a time, making the purchasing decision easier. Electricity has a daily temporal component that is more difficult to price and purchase.

In general, every purchasing alternative available to the District for purchasing natural gas is also available for purchasing electricity.

Risks Faced by the District

Every purchase has risk. This means that every purchase that the District makes has a chance of being the wrong purchase for some reason, including the wrong price, the wrong amount or for the wrong time. Examples of risk include:

Forecasting Risk: The financial risks due to inaccurate forecasts. The District makes its long-term natural gas and energy purchases based upon sophisticated forecasts of demand and energy requirements. If the forecast is too high, the District purchases too much and may have to sell at a loss. If the forecast is too low, the District may not purchase enough in the forward markets and have to purchase additional energy and/or natural gas in the spot markets at a higher cost.

Regulatory Risk: The risk associated with having to meet new market regulations or changes in regulatory directions. An example of this is the GHG emission restrictions imposed by the State after the District had made a substantial investment in a coal-fired generation facility.

Market Price Risk: The risk that forward purchases are made at the wrong time. Energy and natural gas prices fluctuate daily. A purchase made several months (or years) ago may be expensive compared to today's price. Conversely, a sale of energy or natural gas could be made for more today than when it was made in the past.

Counter-Party Risk: The risk associated with purchases and sales to counter-parties that refuse or are unable to perform. This may result in either a loss due to non-payment for energy supplies or an inability to provide contracted deliveries resulting in higher costs to purchase replacement supplies.

Supply Risk: The risk associated with a generation unit or transmission line having a forced outage that affects its ability to provide energy. Failure of a generator may result in having to purchase energy at higher prices or even threaten the reliability of the system.

These are just a few examples of the risk that the District faces in its daily power supply decisions. The District attempts to minimize the effects of risks in its daily purchases of energy and natural gas but it will never succeed in totally eliminating the financial impact of risk.

PURCHASING NATURAL GAS

One of the largest expenses of the District is natural gas supplies for internal generation.

In the wholesale market, natural gas is traded on a million BTU basis, or MMBTU, (sometimes referred to as a decatherm). Natural gas has approximately 1,000 BTU[9] per cubic foot (cf) of gas. Therefore, approximately 1,000 cf of gas is equivalent to 1,000,000 BTU's. Retail natural gas is sold in therms which are 100 cf or 100,000 BTU.

National gas prices are quoted for delivery at Henry Hub, a trading point near New Orleans. The Henry Hub gas is the trading point for all future trades on the New York Mercantile Exchange (NYMEX). However, there are regional trading points where trades occur at prices higher or lower than the NYMEX price depending upon local demand. The difference between the Henry Hub price and a specific trading point is called the basis.

The spot price of gas is the current day's price of gas at a specific delivery point. The future (or forward) price of gas is the price of gas delivered at a specific delivery point at some time in the future. Generally, future prices are for a specific amount of gas delivered each day of the month while spot gas can be any quantity of gas.

The District purchases gas for use in its internal generation at the Southern California Citygate (SoCal Citygate), a virtual trading point created by the CPUC comprised of a number of pipeline delivery points onto Southern California Gas' (SoCalGas) distribution pipelines.

The District also uses natural gas for its Yucca Steam Plant although Arizona Public Service Company (APS) currently purchases all natural gas requirements and then bills the District for

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9 A BTU is the amount of heat necessary to raise one pound of water from 60 degrees to 61 degrees Fahrenheit

actual costs plus administrative fees. The District cannot purchase natural gas for the plant directly due to Federal rules requiring that gas transportation users must have title to the gas. Because APS owns the gas transmission rights to the plant, APS must have title to the gas. The District is studying alternative purchasing methods and transmission arrangements for Yucca gas supplies.

TRANSPORTATION COSTS

Transportation costs comprise a significant portion of the District's natural gas costs. Transportation on SoCalGas' pipeline system is around $0.46/MMTBU while on APS' gas transportation system (used to supply the Yucca Steam Plant fuel requirements) it is around $0.50/MMBTU (including a 7.0 percent utility user tax). This cost is around 10 percent of the total cost of natural gas to the District.

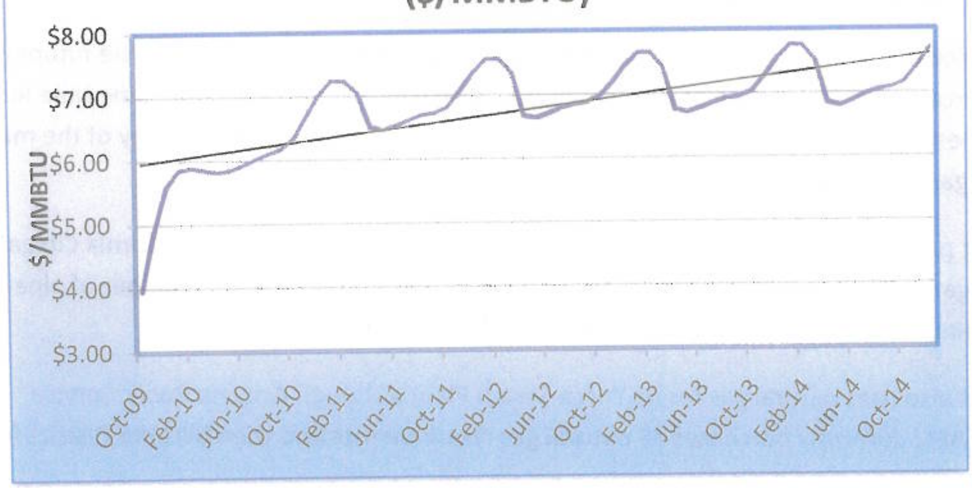
SPOT VERSUS FUTURE PRICES

The price of natural gas has a temporal, or time, value. Natural gas prices vary by day and season even though the trend of natural gas prices may be up or down at any time.

The spot price of gas is the daily price at a specific delivery point, for example Southern California Citygate or Ehrenberg, trading hubs on the western transmission system pipeline.

The forward price curve in Figure 4.1 shows the future price of natural gas for specific months in the future (for delivery at Henry Hub).

Figure 4.1: Forward Price of Natural Gas ($/MMBTU)



Forward curves tend to be upward sloping, reflecting the cost of storing gas from month to month and seasonal demands for gas.

An upward sloping forward curve illustrates why it is difficult for the District to purchase gas years into the future to fix prices. The current forward price for gas delivered in December 2011, for example, is more than double the current spot price of gas. As we move closer to the December 2011 delivery date for gas, the forward price and the spot price will converge. What is not known is whether December 2011 prices will move towards today's spot price or vice versa.

Burner-Tip Prices

Because there are so many additional costs associated with delivery of gas to a generator, use of a contract or daily price under-estimates the cost of producing energy.

Instead of using the spot price as an estimate of gas costs, a better indicator of natural gas costs is the burner-tip price. The burner-tip cost includes the cost of gas, transportation, taxes, scheduling fees and any other cost necessary to deliver gas to the generator.

The burner-tip cost is generally around $.50/MMBTU greater for the District or around 10 percent greater than the cost of the gas commodity itself.

Firm Purchases

The easiest way to purchase gas is a firm purchase of a specified quantity of natural gas at a specific location for a known quantity. For example, the District could purchase 5,000 MMBTU/day of natural gas delivered at SoCal Citygate at either a fixed price or the daily spot price of gas (referred to as the index price).

Firm purchases make up the bulk of IID's daily gas purchases. Firm gas means that if the supplier does not deliver the specified quantities of gas, it will be liable for any additional costs incurred by the District for replacing the contract quantity.

The advantage of a firm purchase is that the quantity, term, price and delivery point are all known. The disadvantage is that prices may decline between the time that the purchase is made and the gas is actually burned.

Call Options

The District uses call options to cap the price it will pay for natural gas.

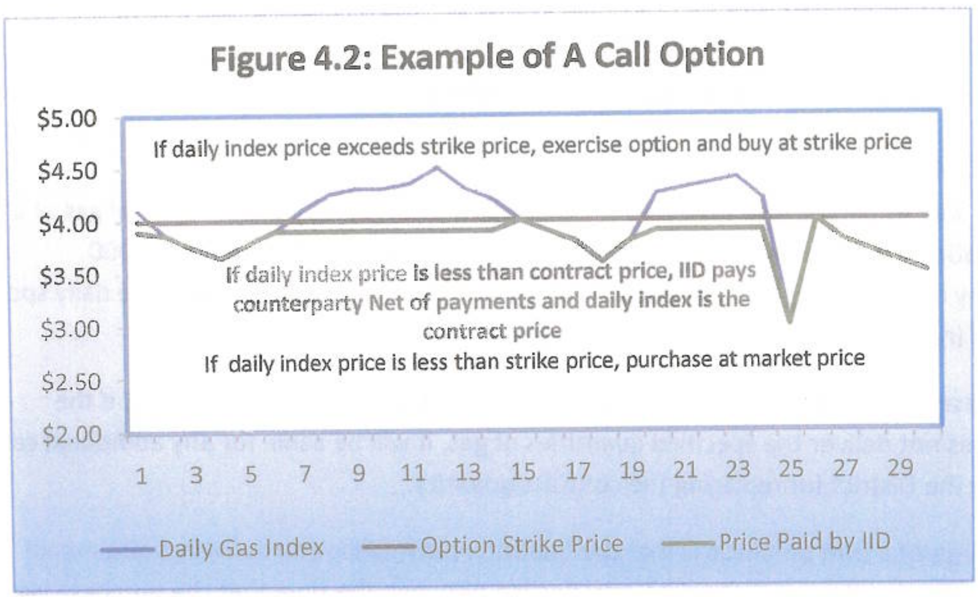
A call option allows the purchaser to buy the right to purchase a specific quantity of natural gas at a fixed price (called the strike price) regardless of the market price. For example, the District may purchase a call option for 2,000/MMBTU per day of gas at SoCal Citygate at a price of $7.50/MMBTU. If gas prices are greater than $7.50/MMBTU, then the District would exercise its right and pay the strike price. If prices were less than $7.50, the District would not exercise its right and instead purchase in the market at the lower price.

The price that the District has to pay for call options depends upon the time left to exercise an option and the strike price relative to the market.[10] The lower the strike price, the higher the option premium. Also, the further out in time the option is, the greater the price reflecting uncertainty about the future direction of the market.

The District has to balance current and forward prices with options. In the best case, any option purchased by the District would not be exercised, meaning that daily market natural gas prices were less than the strike price and the District could buy gas less expensively.

Options are used to cap natural gas costs. An option is protection against the financial impact of high gas prices on the District, but that protection comes with a cost.

Figure 4.2 illustrates how a call option works.



10 Option prices have been studies extensively and depend upon the relationship of the price to the strike price, time to maturity, underlying price volatility and the interest rate

PUT OPTIONS

A put gives the seller the right to sell at a specific price, regardless of the cost of an underlying commodity. For example, the District might buy a put if it felt natural gas costs were falling and it had surplus gas.

Historically, the District has not used puts because the District attempts not to have surplus natural gas that it has to sell in the market.

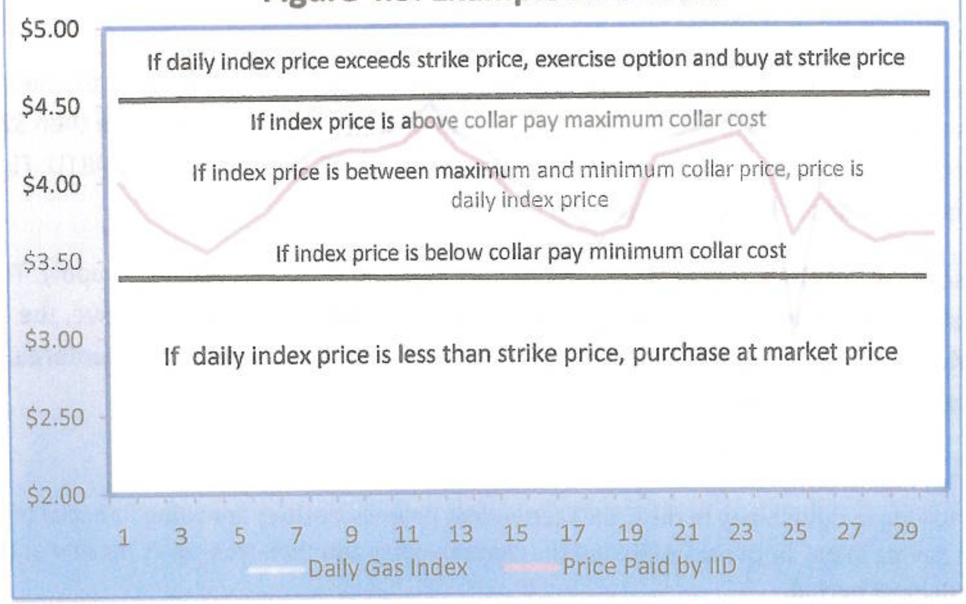
COLLARS

A way for the District to avoid paying the high premium cost of options, especially when gas prices are expected to rise, is to use costless collars. With a collar, the range of gas prices is fixed. A collar with a cap of $7.00/MMBTU and floor of $3.50/MMBTU means that the District will not pay more than $7.00/MMBTU for the gas, regardless of how high the price of gas is during the delivery period. But, the District would also not pay less than $3.50/MMBTU regardless of how low natural gas prices are.

The advantage of a costless collar is that, unlike a call option, the District does not have to pay for price protection. The value of the implicit put is used to offset the cost of the collar.

Costless collars are generally asymmetric. If the future gas price is $4.00/MMBTU, the collar may be from $3.25 to $6.50. If the District wanted a symmetric collar (for example $3.00 to $5.00) then it would likely have to pay the counterparty.

Figure 4.3: Example of a Collar



Financial Hedges

The District has historically not made use of financial hedges, preferring instead to purchase with fixed price and options. However, primarily due to the MRTU market that many counter-parties participate in, financial hedges have become much more common in the California wholesale gas and electric markets and the District is beginning to use them more often for specific purchases[11].

The simplest form of a financial hedge is a contract-for-differences. The two parties agree to a fixed, or strike, price based upon a daily index cost of gas and a specific quantity.[12] On a daily basis, the difference between the spot price and the strike price is due one party. If the price is below the strike price, the District would owe the counterparty while if the spot price was above the strike price, the counterparty would owe the District.

For example, suppose that the District took a three-day hedge for 1,000 MMBTU at $4.00/MMBTU. On day 1, the spot price was $4.10, on day 2 the spot price was $3.75 and on day 3 the spot price was $3.90.

The amounts owed by the counterparty to the District would be calculated as:

*Day 1: (1,000 MMBTU) * ($4.10 - $4.00) = $100.00*

*Day 2: (1,000 MMBTU) * ($3.75 - $4.00) = -$250.00*

*Day 3: (1,000 MMBTU) * ($3.90 - $4.00) = -$100.00*

Total Due Counterparty = -$250.00

The District would pay the spot price to a gas supplier (either the entity that wrote the hedge or any other supplier) $11,750 (the sum of the daily volumes times the spot price) and then $250 to the financial hedge counterparty, resulting in a net cost of $12,000 or $4.00/MMBTU. Figure 4.4 shows how a financial hedge operates:

The purpose of a financial hedge is to lock in the price regardless of the source of supply. The financial hedge actually works as a fixed price purchase. As shown in Figure 4.4 above, the net of the spot price cost plus amounts owed to, or received from, the financial hedge counterparty will be equal to the strike price.

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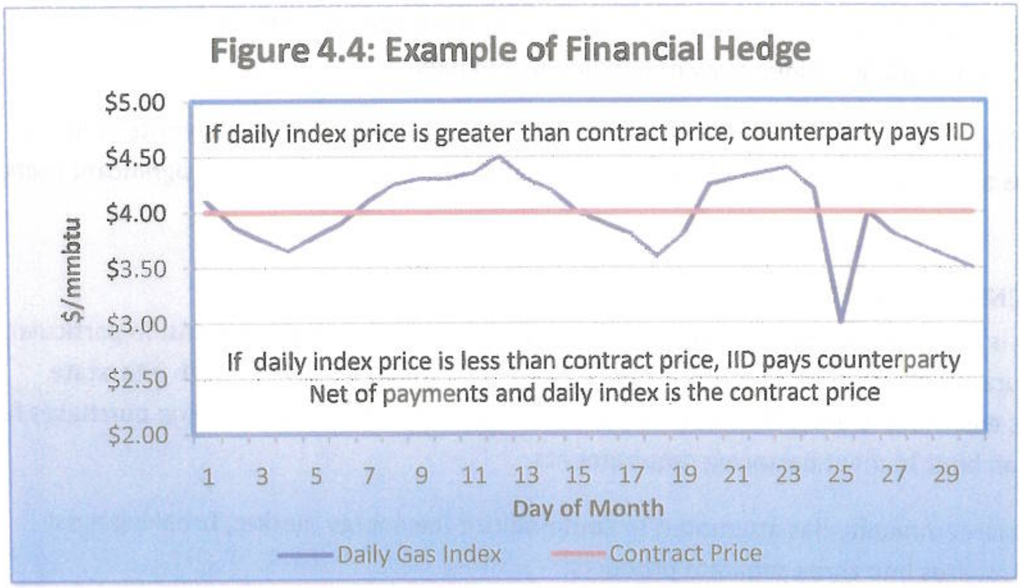
[11] To avoid having to double-pay in the CAISO settlement process, entities are using financial hedges rather than having to pay both the CAISO and the counter-party and then true-up at the end of the CAISO's settlement period.

[12] The usual index is the Platt's Daily Index of Natural Gas for a specific hub or trading point

The advantage of a financial hedge is that it can be done with any financial counterparty so long as an index can be agreed upon. Gas supplies can then be purchased at spot prices from any supplier and the financial hedge used to fix price. This allows entities the opportunity to enter into financial hedges with strong credit counter-parties and buy spot gas from any supplier.



The District does not directly purchase in the CAISO's MRTU energy market and so has not had the need to use financial hedges for energy in the past. However, the District has found the need to use financial hedges for its Yucca gas purchases.

Yucca gas supplies have traditionally been purchased by APS for the District. APS charges the District the physical price of gas and APS will not hedge gas costs for the District. As a result, the District has a large market price risk exposure to gas prices for Yucca.

The District can enter into a financial hedge of its Yucca gas costs. If (for example) the District hedged Yucca gas at $4.00 MMBTU, it would pay APS the spot price of gas and then either receive a payment from the counterparty or owe a payment to the counterparty to bring its cost of gas to $4.00/MMBTU.

SUMMARY

The District has five basic ways to buy gas to meet monthly burn requirements, firm purchases, options, puts, collars and spot gas purchases. In addition, it can use financial instruments to fix gas costs. Balancing the mix of firm purchases, options and collars can insure that the District's monthly gas costs are capped but allow for some downward movement in cost requires that the Planning Group perform sophisticated analysis and market simulations, at the lowest possible cost.

The District does have the ability to meet all of its forecasted monthly requirements using just one method, for example firm purchases or options. But this will almost always result in the District paying more for natural gas than is necessary.

The District has traditionally avoided using some of the more esoteric combinations of options and fixed price combinations even though the electric utility industry is becoming more sophisticated and using a wider array of hedging techniques.

Also, the District has not participated in SCPPA's prepay gas purchase arrangements or in-ground gas purchases. The prepay arrangement would have saved the District significant money over time.

Purchasing Electricity

Electricity is a different commodity than gas with many more purchasing options. In particular, while natural gas is bought and sold for daily delivery (except when dealing with interstate pipelines), electricity is bought and sold for different periods of the day, including purchases for less than an hour to meet balancing requirements.

The financial community has attempted to commoditize the energy market, breaking most energy purchases into three separate products:

- On-peak energy: Energy delivered from hour ending (HE) 0700 to 2200, Monday through Saturday
- Off-peak energy: Energy delivered between HE 2200 to HE 0600 Monday through Saturday and all day Sunday.
- Baseload Energy: Energy delivered for all hours of the day.

In addition, standard products have grown to include super peak, an eight hour block of energy delivered during the highest use periods of the day.

Generally, only standard products can be purchased in the forward markets. Non-standard purchases are made in the day-ahead and hour-ahead markets.

Tolling Agreements

Often, to avoid any market price risk, purchasers prefer that daily gas prices set the purchase price of energy. A tolling agreement (and a heat rate option) allows a supplier to offer different energy prices based upon the daily price of natural gas and a negotiated heat rate.

Tolling agreements and heat rate options differ slightly in that a tolling agreement is for firm, must-take energy while a heat rate option gives the purchaser the right to take the energy depending upon market prices and the terms of the agreement.

With a tolling agreement, the purchaser pays for and reserves the right to call energy at a specific heat rate for some time period. The lower the heat rate, the higher the cost of the option (generally – as with any negotiated contract there are exceptions). A tolling agreement with an 8,000 MMBTU/kWh might have a premium of $5.00/kW-month while a 13,000 MMBTU/kWh strike price may have a premium of $2.00/kW-month.

With heat rate options, the determining factor of how to choose the appropriate heat rate depends upon the forecasted use of the option. If the option is likely to be called on a frequent basis (for example, every weekday afternoon) then the purchaser would likely prefer a low heat rate and a high fixed premium. If however, the option is being used to meet unexpectedly high summer peaks, then the purchaser would want to minimize the fixed premium cost and purchase a high heat rate strike option.

Call Options

Energy call options can be purchased for on, off and super-peak time periods. There are two basic forms – a daily call option or a monthly call option. With a monthly call option, the option must be exercised prior to the beginning of the month and, once exercised, must be taken during the time periods. With a daily call option, the purchaser has the ability to choose to take the energy each day and can choose not to take energy if market prices are below the strike price.

The more flexibility the purchaser has, the greater the price. The premium price is also higher the lower the energy strike price.

Generally, call options are only available for the three standard market products, on-peak, off-peak and super peak.

Summary

The District uses a variety of different instruments to purchase natural gas and electricity. Identifying the right mix of firm purchases, call options and collars, helps insure that the District will have a mix of resources available to meet load reliably while providing flexibility to take advantage of market opportunities and minimize total power supply costs.

The District must also insure that it does not have too many heat rate options in its portfolio. Heat rate options increase power supply cost volatility as energy prices become perfectly correlated with changes in natural gas prices.

CHAPTER 5: FUTURE RESOURCE NEEDS

INTRODUCTION

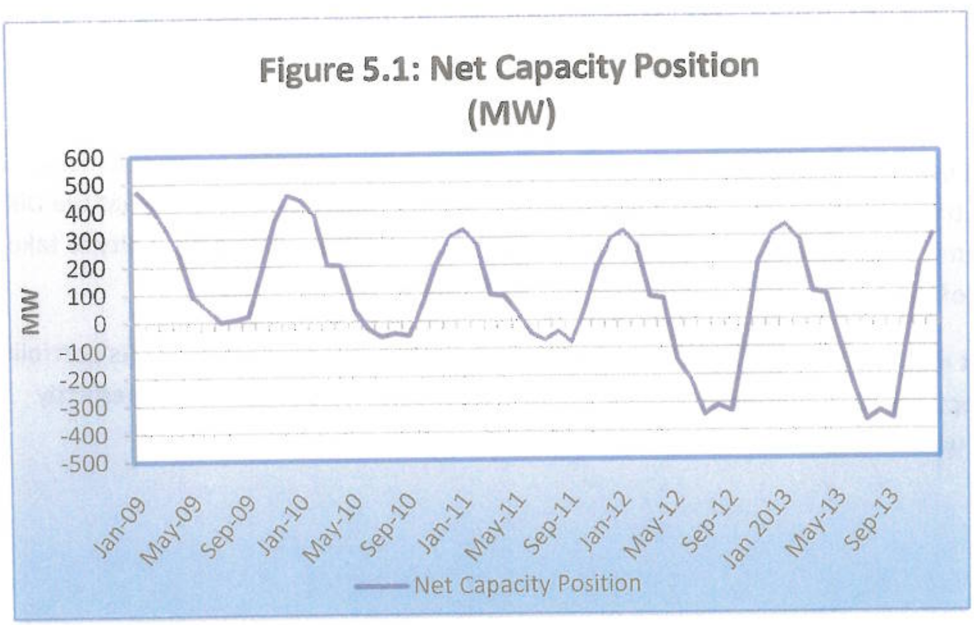
The District has procured sufficient capacity and energy to meet 2009 requirements. The District is short a small amount of capacity (some 20 MW) in 2010 and 2011 due to the planned retirement of the Brawley generation plant (20 MW). Beginning in 2012, the District is short significant amounts of capacity and energy with summer capacity deficits exceeding 340 MW.

In choosing how to meet the District's net short position, a number of factors must be taken into consideration, including the impact of new generation resources on:

- Total power supply costs;
- Renewable portfolio standards;
- Greenhouse gas emissions;
- Ability to provide necessary ancillary services to meet Balancing Authority obligations.

CAPACITY DEFICIT

Figure 5.1 presents the monthly capacity deficit that the District must plan for over the next four years:



Even though the District must acquire sufficient capacity to meet its forecasted loads, it must be careful that it does not pay for energy in excess of its load requirements. The District's capacity requirements are primarily in the April through October time period with excess capacity in the November through March time period.

Types of Generation Resources

There are three basic kinds of generation resources: baseload, peaking and intermediate. Acquiring the right mix of resources is necessary to meet load at the lowest cost.

Baseload Resources

Baseload resources have a capacity factor[13] of between 60 and 100 percent. Baseload resources are characterized by high construction costs and relatively low energy costs. Baseload resources include coal, nuclear, hydroelectric run-of- river and combined cycle generation. In addition, geothermal generation is usually classified as a baseload resource since it is intended to operate for all hours.

Peaking Resources

Peaking resources have low capital costs but high fuel and operating costs. Examples of peaking resources include combustion turbines and older, inefficient generation facilities.

Intermediate Resources

Intermediate resources are, by elimination, resources that are neither peaking nor baseload resources. There are few examples of actual intermediate resources other than hydroelectric resources (with water storage rather than run-of-river) and combined cycle resources. However, many of the modern technologically advanced combined cycle resources are used as baseload resources because of their high efficiency.

Capacity versus Energy Charges

Unless the energy is bought for all hours of the day (a baseload purchase), power purchase agreements (PPA's) include a capacity charge. The capacity charge is the reservation charge for energy and is priced as a cost per kW-month or a fixed charge for the right to generate energy from the contracted capacity.

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[13] The capacity factor is defined as the ration of actual generation to potential generation and is calculated as: Annual Capacity Factor = (actual generation during the year)/(8760*unit capacity). Capacity factors can also be calculated by month with the formula being changed to reflect energy generated during the appropriate time period divided by the potential generation during the time period.

The capacity charge will vary depending upon the expected use of the generator. An agreement that anticipates that the generation facility will be used sporadically during the peak periods of the month will have a higher capacity price than an agreement that contemplates frequent use.

Energy can be priced a number of ways. Generally the price is quoted in the price per MWh – for example, $50/MWh.

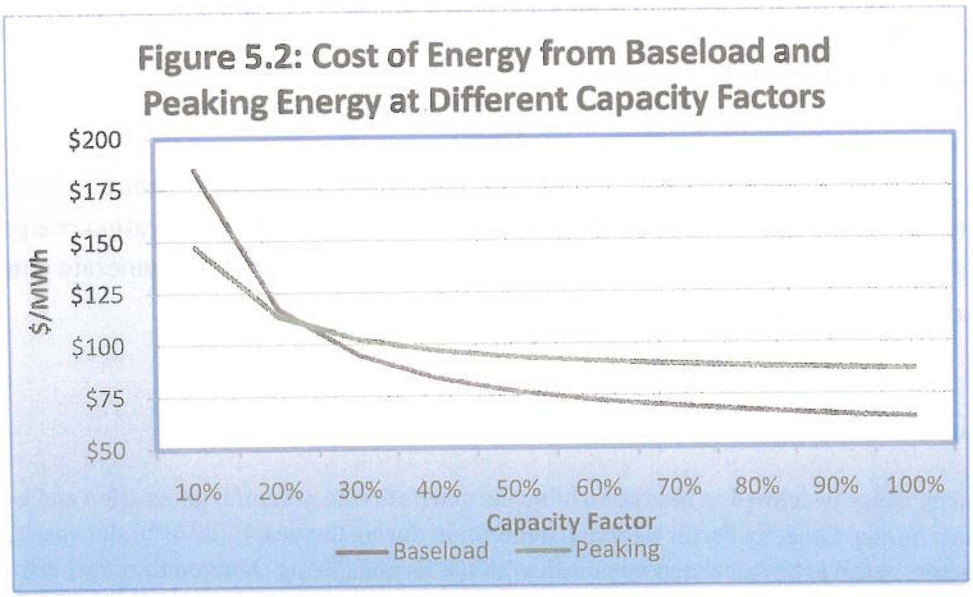
When calculating the total delivered cost of energy, both the capacity and energy cost must be included. Knowing how the resource will be used is important in determining what type of resource will minimize total costs.

Generally, baseload resources have a high capacity factor (reflecting the high capacity costs associated with building baseload generation) and low energy costs. Peaking resources generally have low capacity costs but high energy costs.

If the unit is going to be operated as a peaking facility or with a low capacity factor, the best, or most economic choice of resources, are those with low capacity costs and high energy costs. If the unit is going to be purchased to meet baseload requirements, then a purchase with a high capacity cost and a low energy cost is generally most economic.

Summary of Resource Types

Baseload resources are characterized by high capacity costs and low energy costs and peaking resources are characterized by low capacity and high energy costs. **Figure 5.2 shows the average cost of peaking and baseload generation resources at different capacity factors.**



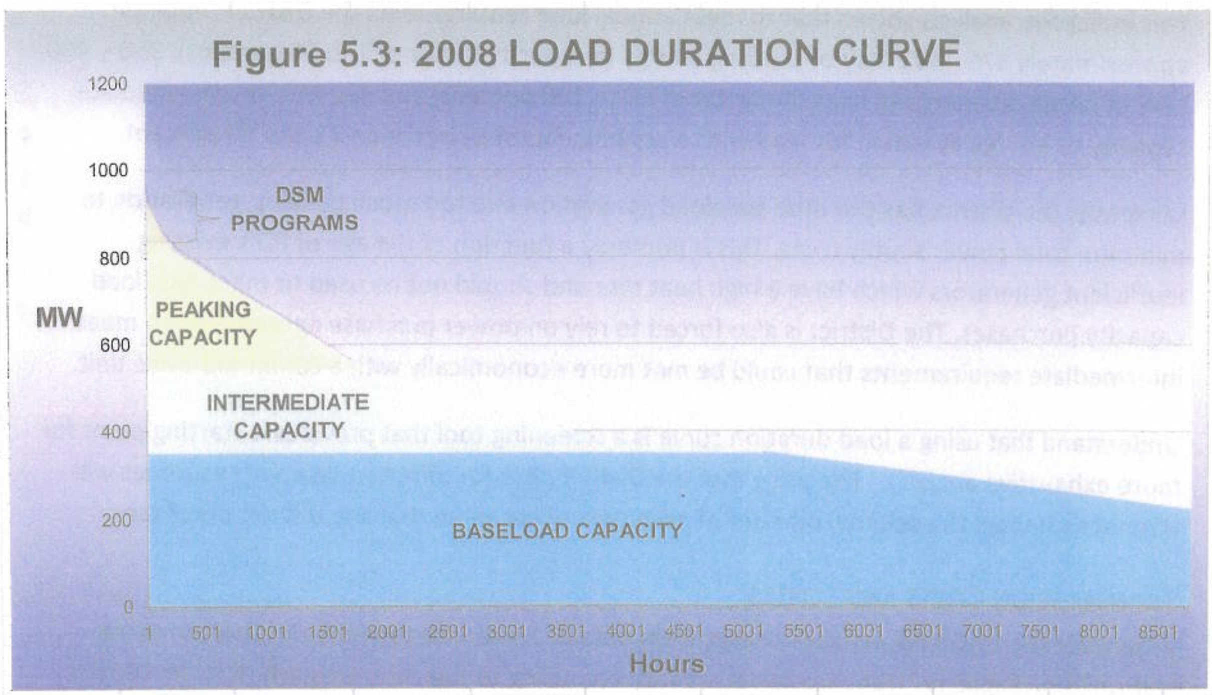
At low capacity factors, the capacity cost of baseload resources dominates the total cost of generation, while at high capacity factors, the high energy and operating costs dominate total costs of peaking resources. As a result, baseload resources should only be acquired when the expected capacity factor is going to be above 60 percent and peaking resources should only be used when the expected capacity factor is below 25 percent.

An important screening tool for identifying the type of resources required by the District is determining the approximate capacity factor of potential new resource additions. Once the capacity factor is identified, appropriate technologies can be specified.

LOAD DURATION CURVE

Another useful screening tool for the type of resources needed in the future is the load duration curve for the District. The load duration curve shows how many hours each year load exceeds specified amounts and provides information on the characteristics of new resources required by the utility.

Figure 5.3 presents the District's load duration curve.



Several interesting facts can be drawn from the load duration curve. First, baseload requirements are around 350 MW. Baseload resources are resources that are available for dispatch all hours of the year (excluding planned and forced outages). Generally, a utility should acquire enough baseload resources so that it is slightly long around 2,000 hours of the year (or roughly 20 percent of the time). The District has control over the dispatch of its resources and can back down the San Juan and Yucca generation plants to reduce any surplus energy.

The second important fact to recognize is that IID's loads are only above 800 MW for around 500 hours of the year and above 900 MW for less than 150 hours of the year. This means that the District is required to purchase expensive peaking capacity during the summer months to meet load that only occurs for less than 150 hours.

As will be shown in a later section, demand-side management programs can reduce the daily peak demands and reduce the need for expensive peaking capacity. If the District can implement 50 MW of demand-side programs, it would be displacing generation resources that are only used around 150 -200 hours per year, primarily during the high cost, on-peak hours.

The load duration curve shows that the District should acquire around 400 MW of peaking capacity or energy required only around 25 percent of the time. This type of energy comes from power purchase agreements and combustion turbines or older, inefficient gas and steam units that have low capacity costs.

This indicative analysis shows that to meet annual load requirements the District requires approximately 375 - 400 MW of peaking energy (a capacity factor of 1 to 25 percent), 350 – 400 MW of baseload energy (a capacity factor of 60 to 100 percent) and 300 MW of intermediate capacity or energy available for load with a capacity factor of between 25 and 60 percent.

Currently, the District has too little baseload generation and too much peaking generation to minimize total power supply costs. This is primarily a function of the age of IID's existing inefficient generators which have a high heat rate and should not be used to meet baseload capacity purchases. The District is also forced to rely on power purchase agreements to meet intermediate requirements that could be met more economically with a combined-cycle unit.

Understand that using a load duration curve is a screening tool that provides a starting point for more exhaustive analysis. The price that the District pays for different types of resources will ultimately impact the optimal amount of each type of resource that the District purchases.

Transmission Costs and Losses

Whenever the District purchases energy from outside its service territory, it must purchase transmission capacity. Transmission costs vary according to the contract path that the District uses.

Purchases from the CAISO are expensive, generally around $15/MWh. The CAISO adds an export fee that includes ancillary services, grid management charges and other costs that purchasers within its balancing authority must pay. The District also does not know if it will be required to pay any congestion charges on the CAISO system, although generally congestion from the CAISO to the District is low. Selling energy into the CAISO does expose the District to potentially high congestion charges.

Purchases from east of the Colorado River tend to have lower transmission charges than from the CAISO, generally around \$3 - \$5/MWh. However, if the energy passes through multiple balancing authorities or substations controlled by different entities, the transmission charges are "pancaked" on top of each other and transmission charges can quickly escalate.

The District also has to account for transmission losses. Some entities (such as the CAISO) deliver the contracted amount and charge the District for losses. Others just deliver the contracted amount less losses. Generally, the magnitude of losses faced by the District is around 3 to 5 percent, although they can be considerably higher if the generation source is in Utah or Colorado.

When the District makes its purchasing decisions, it also includes both transmission costs and any associated losses.

Summary

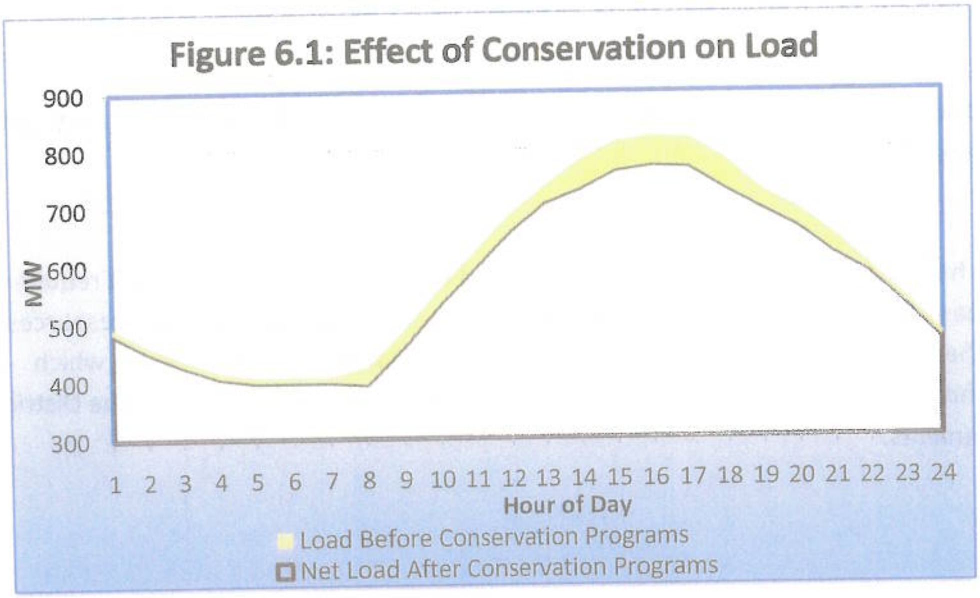
The District has identified both the total resources and the types of resources that it requires on a monthly basis for the planning horizon. The next step is to identify the least-cost resources that meet the District's reliability and counter-party credit standards in determining which resources should be acquired, either through PPA's or District ownership, to meet the District's load requirements.

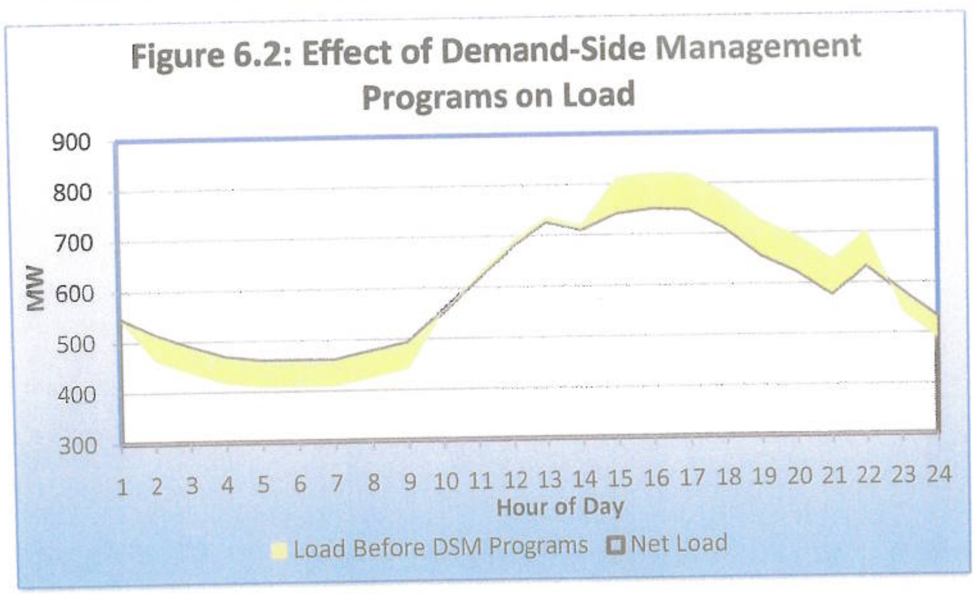
Chapter 6: Conservation and Demand-Side Management

Introduction

Conservation programs are intended to reduce the total amount of energy used in performing a particular task. Demand-Side Management (DSM) programs are intended to shift energy use from high cost periods to low cost periods and reduce the cost of supplying customers.

Figures 6.1 and 6.2 illustrate the difference between conservation and DSM programs.





Most of the District's adopted programs are conservation programs designed with the goal of reducing the customer's consumption and cost of energy. Future programs will be designed with the goal of reducing the District's cost of supplying power while providing some reduction in the customer's energy consumption and costs.

EVALUATION OF PROGRAMS

Conservation and DSM programs can be evaluated in three ways. These are measuring the energy and financial impacts on participating customers, non-participating customers and the utility.

Participating customers are the customers that are taking advantage of the program, either by installing the proposed energy saving device(s) or designing their buildings and appliances in accordance with proposed efficiency standards. Non-participating customers are the remaining customers that do not take advantage of the proposed conservation programs.

Most utility sponsored conservation programs benefit the participating customers. Any increase in utility cost to participating customers is offset by their reduction in energy use and the corresponding savings.

Customers almost always benefit from conservation activities in the long-term. However, like any capital investment, the up-front cost of investing in conservation activities may discourage consumers from making the investment.

As an example, consider the cost of replacing a 60 watt incandescent bulb that costs $1.00 and is used 8 hours per day with a compact fluorescent (CFL) that costs $3.50. The energy cost of the incandescent bulb is $2.16 per month while the energy cost of the CFL is $0.54 per month, a savings of $1.62[14] per month. In slightly more than 2 months the consumer would save the additional cost of the CFL and thereafter would realize a monthly savings. But many consumers try to minimize the initial capital cost without realizing that the less expensive bulb actually ends up costing them almost $20 per bulb per year.

When a large number of bulbs are replaced at one time, the initial capital cost can be high even though total dollar and energy savings would also be greater.

Evaluating the impact of conservation and DSM programs on the utility requires including environmental impacts that do not affect the consumer. The retail customer is not directly impacted by the District's need to meet legislative and regulatory requirements. From the District's perspective, there is a significant financial benefit from conservation and DSM

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[14] Savings based upon 8 hours per day and $0.15/kWh energy costs. The total cost is calculated as (watts * hours * $/watt energy rate)

programs that reduce GHG emissions or help the District meet legislated energy efficiency requirements.

Conservation programs generally hurt non-participating customers that continue to use the same amount of energy. The utility must raise rates to offset the revenue loss due to reduced energy use by participating customers. This results in greater savings to customers that do conserve.

DSM programs tend to reduce utility costs and benefit both participating and non-participating customers. Because the cost of capacity is so great, utilities that implement DSM programs or off-peak load building programs end up with more revenues and lower costs, allowing them to lower costs to both participating and non-participating customer while preserving the financial stability of the utility.

The District is evaluating the financial performance of all of its existing programs and intends to expand existing programs or create new DSM programs that provide the greatest benefits to both participating and non-participating customers. Programs that only benefit participating customers may be scaled back or eliminated unless they have significant environmental benefits to the District that cannot be quantified for customers.

Description of Existing Programs

The District currently offers the following conservation programs to retail customers.

Residential Programs

AC Quality Maintenance Programs

The Quality AC Maintenance Program delivers comprehensive HVAC maintenance and optimum operational efficiency, airflow and refrigerant charge, to residential and commercial customer's equipment. The program is available to all residential and small business customers. The District also has a "Check me" AC maintenance program under which it offers rebates to customers that service their AC units.

ENERGY STAR® Appliance Rebate Program

Prescriptive rebates offered to residential and commercial customers that purchase ENERGY STAR® labeled appliances including central air conditioning systems, refrigerators, room air conditioners, lighting products, home/office electronics, and ceiling fans. The program is available to all customers that install qualifying equipment. Prescriptive rebates are limited to $2,500.

Compact Fluorescent Lamps (CFL)

The District distributes CFLs through several initiatives aimed at reducing energy consumption primarily in residences. Distribution is via the weatherization program, community organizations such as Students for Environmental Protection, workshops, and audits. This program is available to all residential customers.

Power Pledge Program

Allows city residents and/or school students to pledge to reduce their energy consumption by 10 percent and then provides them with access to web based energy consumption tracking software to help them validate their efforts. The Power Pledge Program provides a more interactive environment for customers and provides an opportunity for young people to engage in energy efficiency activities.

Inspector Energy Program

Inspector Energy provides no cost audits of residential homes and provides homeowners with incentive proposals and information concerning IID programs. In addition, Inspector Energy provides educational workshops and a number of other services including rebate program administration.

Weatherization Program

Qualifying low-income customers receive weatherization services to help minimize the effects of weather on household energy consumption. Weatherization services are delivered through a contract with the Southern California Gas Company. This program is only available to REAP participant with electricity as space heat and/or water heat source.

Commercial Programs

Custom Solutions Program

This program offers performance-based incentives for lighting retrofits, high efficiency HVAC, chillers, motors, VFDs, air compressors, and controls. This program is available to large business customers for projects requiring calculated savings approach.

Small Business Direct Install Program

This program retrofits lighting and simple measures in small businesses. The District will pay up to 65 percent of the installed cost through a rebate and customers will pay back the remainder over 6-11 months. This program is available to small business customers with annual electric bills greater than $12,000 but less than $100,000.

Facility Assessments

The Facility Assessments provide no cost energy assessments of businesses that identify energy efficiency savings. The District may provide an incentive as part of the report of the findings. The program targets customers on rates GL and GS with demands over 100 kW.

New Construction Energy Efficiency Program

The NCEEP Program offers design assistance and performance based incentives for the new construction of non-residential projects that exceed Title 24 requirements by at least 10 percent. The program is available to owners and design teams of non-residential new construction or major renovation projects.

California Green Builder

The District has partnered with the Building Industry Association to deliver the California Green Builder (CGB) through-out IID's service territory. CGB provides incentives to builders to provide environmentally friendly construction. The District provides builder incentives for exceeding Title 24 by more than 15 percent, coordination with municipal entities through the GEM program, and promotional assistance for builders. To date, one builder has signed on to the program and five governmental entities have passed resolutions supporting CGB.

Interruptible Rate Programs

The District has begun offering interruptible rates to large commercial and industrial customers that have onsite back-up generation. This generation can be used to reduce load during times of system stress either due to transmission or generation curtailments or if load exceeds forecasted demand.

The District has identified almost 40 MW of onsite generation that could be used for load shedding under this program.

Government and Agricultural Programs

Pumping Efficiency Program

The District's Pumping Efficiency Program offers free pump testing and performance-based incentives for the installation of recommended repairs. It is available to non-residential customers with pumping facilities

Government Energy Manager (GEM)

This program provides municipal governments with an energy manager from District staff. This energy manager augments the city's staff with an energy efficiency professional. The energy manager coordinates energy matters for the city, identifies energy efficiency opportunities, facilitates project implementation, and insures new construction occurring within the city addresses energy efficiency. In addition to upgrading city and school facilities, this program is also providing promotion and outreach to residents and businesses.

Effects of Existing Programs

The conservation programs implemented by the District have saved participating customers around 39,400,000 kWh through 2009 at a cost of approximately $0.06/kWh. The most successful programs, in terms of energy saved, have been the pumping efficiency program, the various air conditioning programs and the energy efficiency auditing for commercial customers.

The District's programs are weighted towards conservation programs intended to reduce the participating customer's costs. In the future, the District would likely move to implement more DSM programs to reduce the costs to both participating and non-participating customers.

A new state law (AB 2021) requires all municipal utilities to perform third-party measurement and verification studies of their conservation and DSM programs. This means that a California Energy Commission (CEC) approved vendor with experience in measuring the effects of conservation and DSM programs will audit the reported energy savings attributed to each of the District's programs.

The audit results will allow the District to determine if its various programs are effectively reducing energy use of its residential and commercial customers.

Once the audit results are available to the District, all the existing programs will be evaluated to determine if the more cost-effective programs should be expanded at the expense of some of the less effective programs.

PROPOSED PROGRAMS

The District is implementing a number of demand-side management programs to be implemented in 2010, including:

ICE BEAR THERMAL ENERGY STORAGE PROGRAM (ICE BEAR)

The Ice Bear is a 5 kW thermal energy storage program designed to reduce air conditioning loads for small commercial and large residential air conditioning systems. The Ice Bear creates ice during the off-peak hours and uses the ice during the on-peak hours for air conditioning, allowing the air conditioning to turn off the compressor system.

A trial project of 10 MW (2,000 Ice Bear systems) is planned to begin in 2010.

The benefits of the Ice Bear system are dependent upon how many hours the unit must run to create ice necessary for on-peak cooling. In more temperate parts of the country, the Ice Bear can create enough ice during the 16 off-peak hours to allow the compressors to remain off during the 8 on-peak hours. In the District's two major load zones, El Centro and La Quinta, temperatures may be so high that the Ice Bear must make ice for up to 20 hours, resulting in only 4 hours daily of load reduction.

The pilot project will be used to determine if the Ice Bear operating requirements saves enough money in capacity and energy costs to offset the higher capital costs of the units. A typical 5 kW Ice Bear system costs around $12,000 or roughly twice the cost of a traditional AC system. The only way that these can save the District (and ratepayers) money is by shifting enough load to the lower energy cost hours. If the Ice Bear must operate during the higher cost on-peak hours, the energy savings are lost.

Energy SwingShift

This program is intended to allow the District to curtail residential and small business AC and pool pump loads during the on-peak period. The program provides the District with customer demand curtailment capability through the use of direct load control devices and communicating programmable thermostats. The goal of program is to enroll 7 MW of curtailable load over the next two years.

The SwingShift program is in competition with the District's proposed new smart meter systems that may provide the same type of load interruption capabilities as the SwingShift program. Eventually, it is likely that the two programs will be merged.

Key Customer Demand Response Program (Interruptible Load Program)

This program is under development with a target participation of 25 MW over the next three years. Program will require customer to curtail a minimum of 500kW upon a timed notice by IID. Failure to curtail contracted reduction in demand will result in a financial penalty. Program impacts will be verified using IID meter.

Large Thermal Energy Storage System

This program will supplement or replace AC systems for large customers such as hospitals and large office buildings. In an area as warm as the District's service territory, TES systems tend to be larger than in more temperate climates. Sufficient ice must be made during the off-peak hours to keep the compressors from having to be operated during the super peak periods. Because TES systems must be over-sized, the additional cost may limit the value of TES systems except in specific applications where the customer has a high on-peak AC load.

Commercial Lighting Program

This program utilizes existing incentives and adds a lighting retrofit contractor incentive. These contractors will contact eligible customers and evaluate lighting retrofit opportunities. This program has the potential to reduce summer peak demand by over 10 MW and provide annual energy savings over 29,000 MWh.

AC Early Retirement Program (AB811 financing)

This program targets units with 10 SEER or less with the latest Title 24 compliant or better AC and heat pump units. The program is designed for the early retirement of older inefficient central air conditioners and heat pumps. This program has the potential for 9,000 replacements reducing summer peak by 4.3 MW and energy savings of 7,700 MWh over five years. This can be accelerated with an attractive financing program.

The program is intended to take advantage of AB 811 financing that allows customers to borrow from public entities (including potentially the District) and then pay through their annual property taxes.

SUMMARY

The District has implemented a wide range of conservation and DSM programs to try to change how ratepayers use energy. In the next year, the District will evaluate the effectiveness of the different programs and determine which (if any) should be scaled back and which should be expanded.

This evaluation of programs is due to two factors. First, new State regulations require utilities to perform measurement and verification to insure that the reported energy savings are actually being realized. Secondly, the District is attempting to bring spending on conservation and demand-side management programs into line with moneys received under the Public Benefits Charge component of rates. Currently, the District is spending more on Public Benefit Programs, including conservation and DSM programs, than it is receiving from this charge. If the program funding is reduced, the District wants to insure that the remaining programs are the most cost-effective and provide the greatest benefits to participating customers, non-participating customers and the District itself.

The District has established a goal of reducing load by about 50 MW in the next five years. This will require the District to identify the most effective conservation and cost-benefit programs and market these programs more aggressively than in the past.

CHAPTER 7: THE DISTRICT'S TRANSMISSION RESOURCES

INTRODUCTION

The District owns and operates a high voltage transmission system and retail distribution facilities. IID's service area extends over 6,471 square miles. Its transmission and sub-transmission system includes 1,675.4 miles of overhead transmission lines; its distribution system includes 3,480.0 miles of overhead lines and 1,240.2 miles of underground lines.

Figure 7.1 depicts the District's service area and its neighboring utilities and major transmission lines[15].

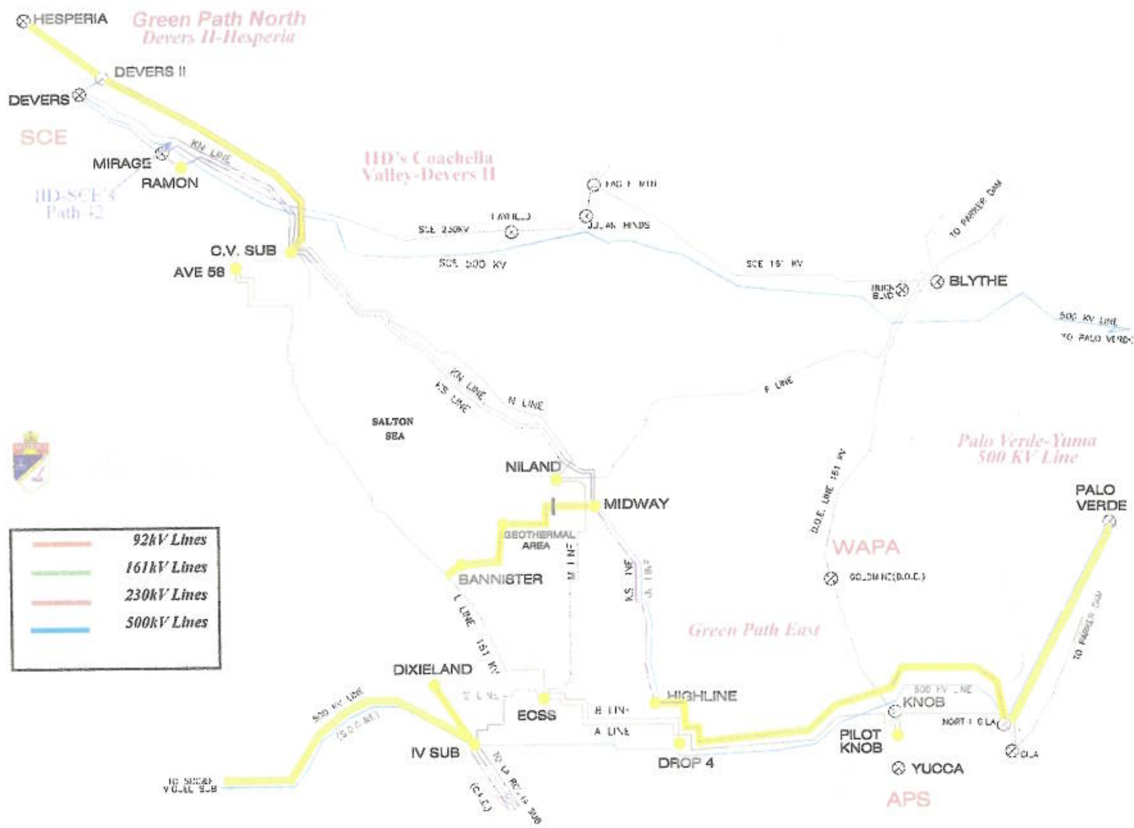


Figure 7.1: District Transmission

15 NERC requirements prevent the District from providing too much detail on transmission projects and locations.

The District's Transmission System

The District's transmission system consists of 500kV, 230kV, 161kV and 92kV transmission lines. The transmission system is used to wheel bulk power supplies into and through the District's control area.

500 kV Transmission System

The District owns a portion of the Southwest Power Link 500 kV line. This transmission line connects the Palo Verde Substation, a major wholesale electric trading hub, to the North Gila 500 kV-69 kV substation near Yuma, Arizona. The line continues from North Gila to the Imperial Valley 500 kV-230 kV Substation in El Centro.

230 kV Transmission System

There are two major components that comprise the District's 230kV transmission system. The first is a single circuit line between the District's El Centro Switching Station in El Centro and the Imperial Valley Substation that is jointly owned by the District and SDG&E (the "S" line). The second is a double circuit transmission line that runs south to north through the District's service territory and interconnects the District's service territory with SCE at the Devers and Mirage substations (KN/KS lines).

The KN/KS line is also known as the IID's "Collector System" that runs south to north across the District's service area to SCE's Mirage Substation. One circuit interconnects at Mirage Substation and the second circuit continues west to Devers Substation through SCE's 230 kV line.

Four transmission substations interconnect to the collector system (Highline, Midway, Coachella Valley and Ramon substations). The interconnection with SCE is established at Coachella Valley Substation with Coachella Valley - Devers 230 kV "KN" line and at Ramon Substation with the Ramon- Mirage 230 kV "KS" line. The IID-SCE interconnection is defined as WECC-Path 42.

The 230 kV Collector System was constructed in 1983 for the primary purpose of delivering over 500MW of "power generating facilities," mostly consisting of renewable resources contracted to SCE at that time.

161 kV Transmission System

The 161kV transmission system consists of a ring across IID's service area that interconnects several 161kV/92kV transmission stations, providing transformation capacity from the 161kV system to the 92kV system. It also provides interconnection to Western through two 161kV transmission lines, from IID's Niland Substation to Western's Blythe substation and from IID's Pilot Knob Substation to Western's Knob Substation.

This system has met the load serving requirements of IID for over 50 years. However, as the load continues to grow in all regions of the IID service area, planning for necessary system upgrades has been ongoing.

The existing system has also experienced additional stresses due to generating resources constructed near the edge of the IID service territory.

92 kV Transmission System

The 92kV transmission system consists of multiple transmission lines that provide interconnection to the distribution substations (92kV/13.2kV) that are constantly constructed and upgraded to provide transformation capacity to the distribution system.

IID Transmission Expansion Plan

In the late 1980's, IID upgraded its transmission system by building a collector system to accommodate the interconnection of new geothermal generation and to export this renewable energy to Southern California utilities. Today, the District wheels approximately 580 MW of geothermal energy from Imperial Valley into the California Independent System Operator (CAISO) balancing authority area. With new planned upgrades, the District's exports are expected to increase to almost 1,800 MW by 2014.

Over the last few years, IID has reviewed and developed a detailed long-term transmission plan (10-year timeframe) to define the transmission improvements necessary to continue meeting the load service requirements in future years. The plan has primarily focused on the upgrade of certain sections of IID's 161kV and 92kV transmission system to 230kV to integrate the existing 230kV collector system and create a 230kV transmission loop that will cover most of IID's service area. The District's transmission plans also include upgrading/building transmission facilities to increase import/export capacity to neighboring balancing authorities.

IID developed its Transmission Expansion Plan to meet forecasted load growth and to provide for transmission of Imperial Valley renewable generation to neighboring transmission systems.

IID's Transmission Upgrade Projects

The District is working closely with neighboring balancing authorities to develop new transmission projects to enhance its Import/Export capability from IID to Southern California and Arizona.

APPROVED PROJECTS:

The following projects have been approved by the District's Board of Directors.

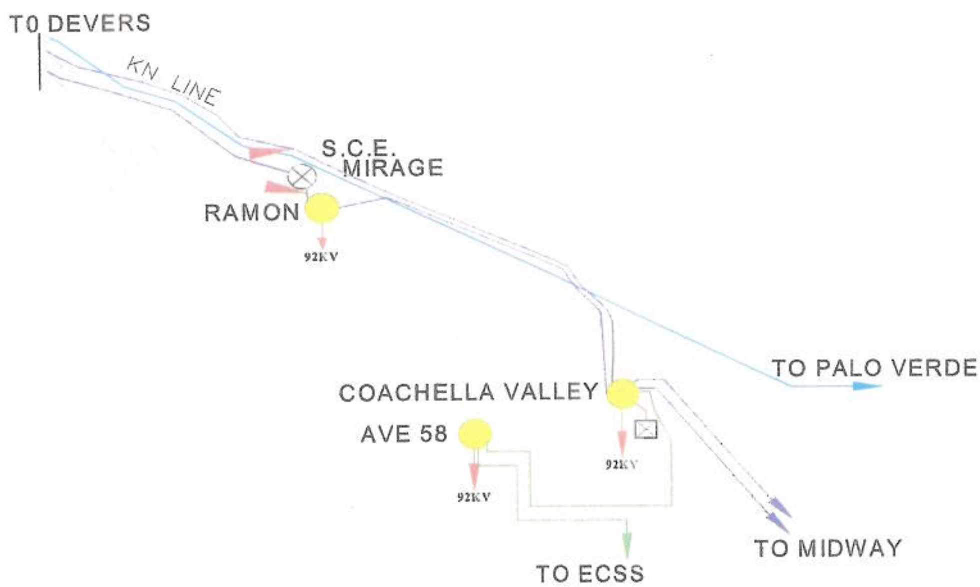
Path 42 Upgrade

Path 42 consists of a double circuit 230 kV line beginning at Coachella Valley substation and terminates at SCE's Mirage substation, approximately 20 miles away. The upgrade will increase the transfer capacity from Coachella Valley to Mirage by approximately 1,200 MW.

The District has recently completed an open season for long-term wheeling contracts on Path 42. Over 1,550 MW of capacity was requested, well in excess of the 1,200 MW available.

Under the terms of the open season, generators requesting wheeling capacity will pay for all transmission studies and system upgrades. The generators will be reimbursed for necessary system upgrades through transmission credits. Once they have been reimbursed for their contribution to system upgrades, they will begin paying the District's wheeling charges.

Figure 7.2: Path 42

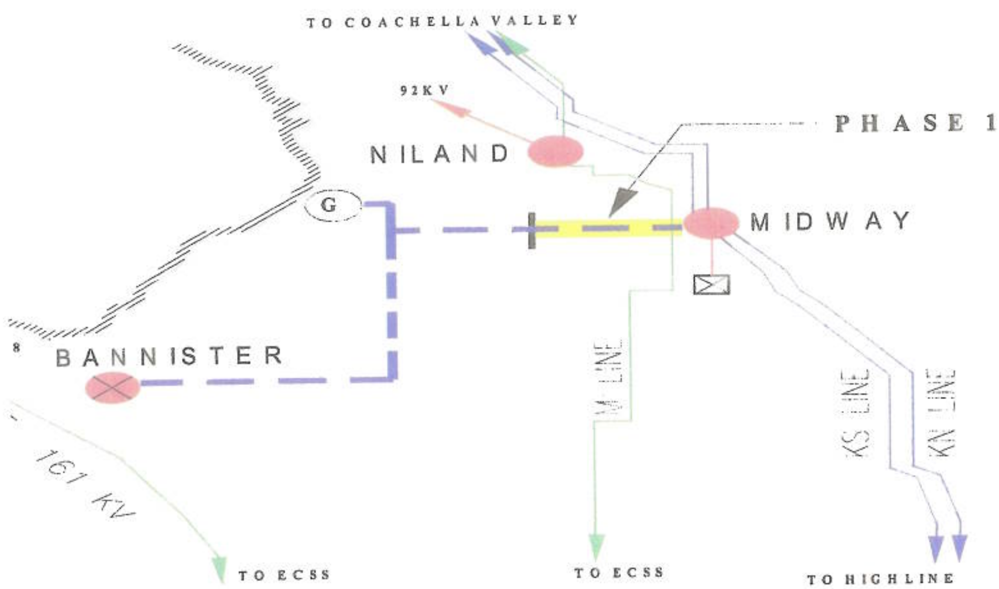


Midway to Bannister Transmission Project

On February 19, 2008, the Board of Directors approved the construction of the first phase of a 35-mile 230 kV transmission line that will interconnect the District's Midway substation to a new Bannister substation. The 230 kV Midway-Bannister line will run right through the heart of the

Salton Sea geothermal resource area and provide access to the District's collector system for renewable generation being developed in this area. The project in-service date is June of 2011.

Figure 7.3: Midway-Bannister Transmission Project



Dixieland-IV Transmission Project

The Dixieland-IV project was approved by the Board of Directors in November 2006. This is an eight-mile line that will connect the Imperial Valley Substation to the District's Dixieland substation. The project will increase the import/export capability from the District to SDGE. The project in-service date is March of 2012.

Ave 58 Substation Transformer addition

The Ave. 58 Transformer addition consists of installing a new 161\92kV, 225 MVA auto-transformer in parallel with the existing one. The project in-service date is June 2011.

PV-North Gila Transmission Project

The IID Board of Directors approved a Memorandum of Agreement (MOA) between IID, APS, Salt River Project ("SRP") and Wellton-Mohawk Drainage District that addresses its participation with these entities in the initial work (Phase I Work) of the Palo Verde – Yuma 500 kV Transmission line Project. The 117-mile line will be capable of transporting up to 1,200 MW of energy. The project expected in-service date is 2014.

Planned Projects

Imperial Valley Substation – Midway Substation- Coachella Valley Substation 500 kV Transmission line project.

The Imperial Valley Substation - Midway Substation- Coachella Valley Substation Transmission line project consists of a single circuit 500 kV line from IV substation to Midway Substation and a single circuit 500 kV line from Midway Substation to Coachella Valley Substation connecting to SCE's Devers Substation through the proposed Coachella Valley- Devers II transmission project. The project includes the installation of two 1,120 MVA 500/230 kV transformers at Midway substation and series compensation in both segments of the line, the expected rating of the line segments will be between 1,200 to 1,600 MW.

Future Projects

As new renewable resources are developed within the District's service territory, the need for additional transmission to the CAISO will increase. The District's Path 42 upgrades will meet a portion of the near term requirements but ultimately a new 500 kV transmission line with a capacity of around 1,500 MW will be required to meet the District's export obligations.

East-West Projects

The District is working with Caithness Energy on the Desert Southwest Project between Blythe and Coachella Valley. This project started in 2001 to bring energy from Western's control area as a way to bring in additional energy from the east.

The permitting and environmental work has been completed. However, the project has been stalled for a variety of reasons, including the final configuration. There is no completion date for this project at this time due to west of Devers upgrades and transmission issues that must be resolved on Western's system.

South-North Projects

The District is looking at a number of alternatives for south to north transmission through the Imperial Valley, including:

Partnering with a private developer to build a new 500 kV line from North Gila to Midway substation and then continuing to SCE's Devers Substation near Palm Springs. A second "leg" of this line would connect Midway to either El Centro or Imperial Valley substation.

Western has proposed this same line as a joint development between a number of entities, including utilities and private developers. The primary difference between the District's proposal and Western's is ownership of the Midway Substation.

Midway Substation is a primary collection point for geothermal development at the south end of the Salton Sea. The District prefers that any geothermal development interconnect with the

District's transmission system and be wheeled to Midway Substation where it could be wheeled north on a new transmission line.

If Midway Substation is owned by a third-party, or a new substation is constructed, that allows generators to interconnect directly with the new line and avoid paying wheeling charges to the District, the District faces the problem of not receiving wheeling revenues to support past investment in transmission facilities. This is also called "stranded investment" as the transmission resources developed by the District in advance of the new line can no longer rely on payments from generators to pay the annual debt costs of the District's investment.

The District will oppose any attempt by generators or new transmission owners to by-pass its transmission facilities.

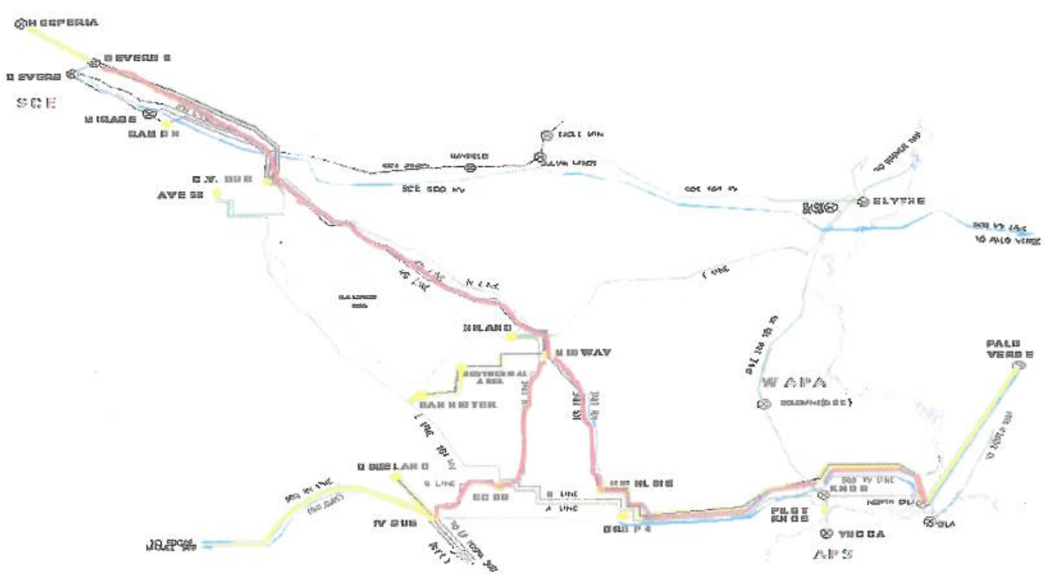


Figure 7.4: Western's Proposed Transmission Study Project (--)

Coachella Valley – Bannister 500 kV Line (CV-B) (Greenpath)

The CV-B used to be called the Greenpath West line, part of a proposed transmission project proposed by the Los Angeles Department of Water and Power (LADWP). The line extended from the Districts Coachella Valley substation north to LADWP's transmission system in Hesperia.

There has been significant environmental opposition to the line by Riverside and San Bernardino Counties and LADWP has announced that it will review the feasibility of the line.

The District sees no immediate need for the CV-B portion of the line. If LADWP wants to have the line constructed, the District will build and own the line, at LADWP's expense. However, at this time, the District does not intend to proceed with this project on its own.

SUMMARY

The District will need to expand its ability to export renewable energy to the CAISO marketplace. The Path 42 Upgrades has already been fully subscribed and additional renewable generation is requesting transmission north from the Salton Sea area to Devers substation.

There have been a number of proposed alternatives for a new 500 kV line, primarily connecting North Gila to Midway and then north, interconnecting with Devers. Some of the proposals also include a new 500 kV line interconnecting the Imperial Valley substation (a CAISO controlled substation) to Midway substation.

The District will continue work on developing another major transmission project, either by itself or in partnership with other entities. The District recognizes that additional transmission is necessary and that some entity will build a new transmission line in the future.

From a generator's perspective, the new line cannot come soon enough. Even under optimistic scenarios, no additional transmission will be constructed until the 2015 or 2016 timeframe.

CHAPTER 8: POTENTIAL NEW RESOURCES

INTRODUCTION

The load duration curve indicative analysis of the District's future resource requirements provides the beginning of the formal studies of the District's future resource needs. The District's analysis begins by adding new resources to its existing generation mix in an attempt to determine the long-term least-cost resource set that satisfies legislative and regulatory requirements.

Even with new generation resources, the District will still rely on short-term PPA's and options to meet a portion of its needs, particularly during the summer months. It is unlikely that the District would ever acquire enough District-owned generation and long-term PPA's to meet all of its retail requirements.

EL CENTRO 3 REPOWERING

The District is investigating repowering Unit 3 of the El Centro Generating Plan (EC3). The initial analysis has identified the need for additional baseload generation and regulating capability.

The EC3 repowering project consists of two 50 MW gas-fired generators, a heat recovery boiler and steam turbine and duct burning. The facility can operate with one or two generators and with or without the heat recovery boiler. This gives the District the ability to maximize daily generation from the unit between (approximately) 25 MW up to 145 MW.

The unit would be very efficient with a design heat rate of around 7,400 BTU/kWh or roughly 33 percent better than the District's Yucca Power Plant which is currently used for regulation.

The estimated cost of the EC3 repowering is $250,000,000, including financing costs and contingency reserves.

If the project is ultimately approved by the District's Board of Directors in January 2010 the project can be completed by the summer of 2012.

SOUTHERN CALIFORNIA PUBLIC POWER AGENCY (SCPPA) GEOTHERMAL PROJECT

SCPPA has begun a project to develop geothermal resources in the Imperial County. The SCPPA Geothermal Project is comprised of the Los Angeles Department of Water and Power (LADWP), the District and the Cities of Glendale, Burbank, Pasadena and Colton. LADWP is the largest project participant with 50 percent of the project while the District has 32.3 percent.

The initial phase of the project is 50 MW with the possibility of continuing development up to 200 MW. The project is expected to come on-line by 2014.

Geothermal Request for Proposal

In April 2009 the District issued a Request for Proposals (RFP) from geothermal developers within Imperial County. The purpose of the RFP was to contract for approximately 50 MW of geothermal generation by 2013 to meet the District's renewable energy requirements and greenhouse gas emission reduction requirements at the lowest cost.

The District also wants to investigate the possibility of a joint public-private partnership with geothermal developers to develop District owned lands with geothermal potential located near the Salton Sea.

The purpose of a public-private partnership would be to allow the District to take advantage of tax incentives available to private entities while at the same time using tax-free financing to further reduce costs.

The District has received proposals from essentially all of the geothermal developers located in Imperial Valley.

The District hopes to develop two 50 MW flash geothermal generation facilities of which it will enter into power purchase agreements for slightly more than half the output from each facility for 60 MW of total capacity. The remaining 40 MW of geothermal generation would be offered to SCPPA members, allowing the District to use SCPPA as a financing entity.

The District is also investigating the possibility of a small experimental geothermal project with around 5 MW of total capacity. This experimental technology uses little or no water and would address the water availability issues that the District must address in all generation projects.

Other Renewable Projects

In addition to geothermal resources, the District is investigating other types of renewable resources, including thermal solar generation, wind, biomass and biodiesel.

In early 2009 the District issued an RFP for renewable resources. Over 45 responses were received covering virtually all the different renewable technologies currently available.

After a long evaluation of the responses, the District planning staff recommended negotiating a power purchase agreement for 20 MW of thermal solar or photovoltaic generation be negotiated with a proposed online date of 2012 or 2013.

Upon completion of the proposed 77 MW of geothermal generation, 20 MW of solar generation and 18 MW of biomass in addition to the District's 35 MW of small hydroelectric generation, the

District will have 150 MW of renewable resources generating almost 25 percent of the District's annual load requirements by 2014.

THERMAL GENERATION

The District has been evaluating other thermal generation resources proposals. These proposals range from long-term power purchase agreements to asset ownership of generation constructed by other entities.

The District has identified the appropriate amount of generation by type (base, peaking and intermediate generation).

Some of the proposals have come from gas-fired generation south of the border, such as the Intergen facilities and Shell's La Rosita facilities. North Branch, a developer of large gas-fired generation, has also proposed a long-term project.

These different resources will be evaluated in the next chapter.

RESOURCES UNDER STUDY

The District is studying a number of potential resources to meet future requirements. While many of the resources are renewable resources using proven technologies, three of the renewable resources are experimental.

G-THERM GEOTHERMAL TECHNOLOGY

The G-Therm geothermal technology installs a heat exchanger deep underground where water (or some other medium) is converted to steam. Unlike conventional geothermal technologies where hot brine is extracted from the earth and then goes through a heat exchanger above ground where water is converted into steam to power the turbine, the G-Therm technology has all the heat exchange equipment below ground.

From the District's standpoint, there are two benefits of this technology. The first is that here is little or no cooling water necessary for generation. The second is that generation units can be as small as 5 MW rather than the typical 50 MW facility needed by current technology to achieve cost-effectiveness. The G-Therm units have a lower cost per MWh than current technologies.

The District is currently negotiating with G-Therm on an experimental plant in the Salton Sea area. There is no guarantee that negotiations will ultimately be successful.

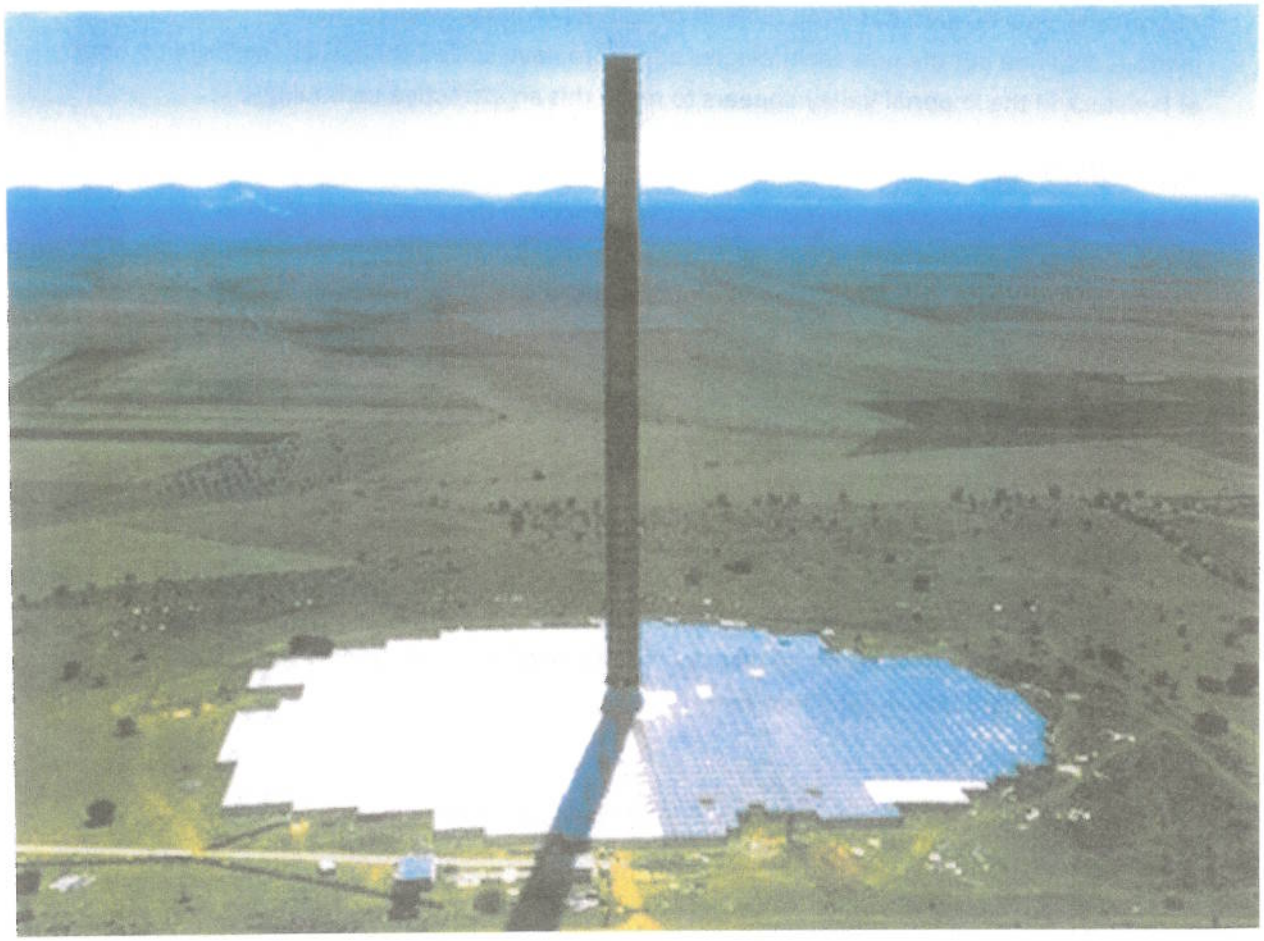
SOLAR TOWERS

A very promising technology is a solar tower. Solar towers are essentially chimneys that force air from the ground upward through tall towers, powering wind turbines. There have been a number of small scale (8 to 20 MW) demonstration project developed around the world in the past five years.

SCPPA is studying a solar tower in La Paz, Arizona. The proposed solar tower, illustrated in Figure 8.1, is more than twice the height of the Empire State building.

Energy from the solar tower is priced comparably to geothermal energy with little or no water use.

Figure 8.1: Solar Tower



Bio-Methane

The District currently uses biodiesel in some of its generation units to reduce GHG emissions. It is currently studying the use of bio-methane or bio-gas as a means of reducing GHG emissions.

There are a number of technologies that collect digester gas from the decomposition of waste and then use this gas to power gas-fired generators. However, there are few large scale examples of successful biogas generation.

The District has a large supply of cow manure. New technologies can collect the biogas from decomposing cow manure in large covered digesters, collect the gas and then scrub the gas of hydrogen sulfide and carbon dioxide and then inject the gas into Southern California Gas Company's gas distribution system where it can be burned in any of the District's gas-fired generation.

Biogas can be collected and treated for around $12.00/MMBTU or approximately $100/MWh using the District's existing thermal resources.

Historically, cow manure has been difficult to convert to biogas due to the high levels of hydrogen sulfide but the new technologies appear to have solved this issue. The large number of livestock in the Imperial Valley appears to make this an attractive technology.

Algae Biodiesel

At least three firms in Imperial County are now engaged in the production of biodiesel from algae. During photosynthesis, algae capture carbon dioxide and sunlight and convert it into oxygen and biomass. The production of biofuels from algae does not result in a reduction of carbon dioxide in the environment because the carbon dioxide is released when the biofuel is burned.

Algae produced biofuel can be used as fuel for some of the District's existing thermal resources.

Algae can be grown in briny water and salt water, making it a potentially good fit for the poor quality water in the Imperial Valley around the Salton Sea.

Currently, algae biodiesel is expensive with costs exceeding $17 MMBTU. However, within the next few years algae based fuels should significantly decline in cost as new technologies are used to grow and convert algae into fuel.

Summary

The resources that the District will acquire in the next few years will be based upon proven technologies used across the world. The District is already looking to 2016 and the technologies that will help meet additional RPS and GHG emission reduction requirements.

The next section discusses how the District chooses new generation resources to add to its resource portfolio.

CHAPTER 9: POWER SUPPLY COST SIMULATIONS AND RISK MANAGEMENT

INTRODUCTION

The District's uses a long-term planning simulation model[16] to estimate long-term power supply costs. The model uses the forecasted loads, future natural gas prices and the District's existing generation resources and power supply contracts to model power supply costs over some time horizon often extending out to 30 years. By adding (or removing) power supply contracts or new generation resources, the model can estimate long-term power supply costs.

The simulation model allows the District to perform statistical studies of the results, including identifying confidence intervals for power supply cost estimates.

RESOURCE MODELING

The District currently has resources secured for 2010-11 to meet IID's forecasted peak demand and to achieve resource adequacy as mandated by the California Energy Commission. By 2012, several contractual agreements will be expiring, the Brawley Gas Turbines will be decommissioned, and the peak load requirements are forecasted to grow leaving IID considerably short in position to meet capacity requirements. Furthermore, these events all occur in the wake of an amplified need for ancillary services (i.e. Automatic Generation Control (AGC), Regulation, Spinning and Non-Spinning reserves, etc.) due to the expansion and development of renewable resources to come within the next several years[17].

With these impending needs in the near term, the District needs a solution that meets it's planning standards while resulting in a minimal rate impact to District ratepayers.

As the District approaches 2012, it also faces the expiration of several key contracts that currently provide capacity to serve the District's system demand through 2011. These expiring contracts include:

- The RFP #484 Option/Must Take products from Shell and J. Aron that combine for a total of 100MW (75MW from Shell and 25MW from J. Aron) of seasonal on-peak power.

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16 Ventyx's ProSim hourly simulation model

17 Unless the District and CAISO can negotiate a dynamic scheduling agreement to minimize the need for the District to have ancillary services for intermittent resources.

- The recently contracted EPE replacement products from Morgan Stanley, Shell, and Oxy which total to a maximum of 150MW of seasonally shaped on peak and off peak power.

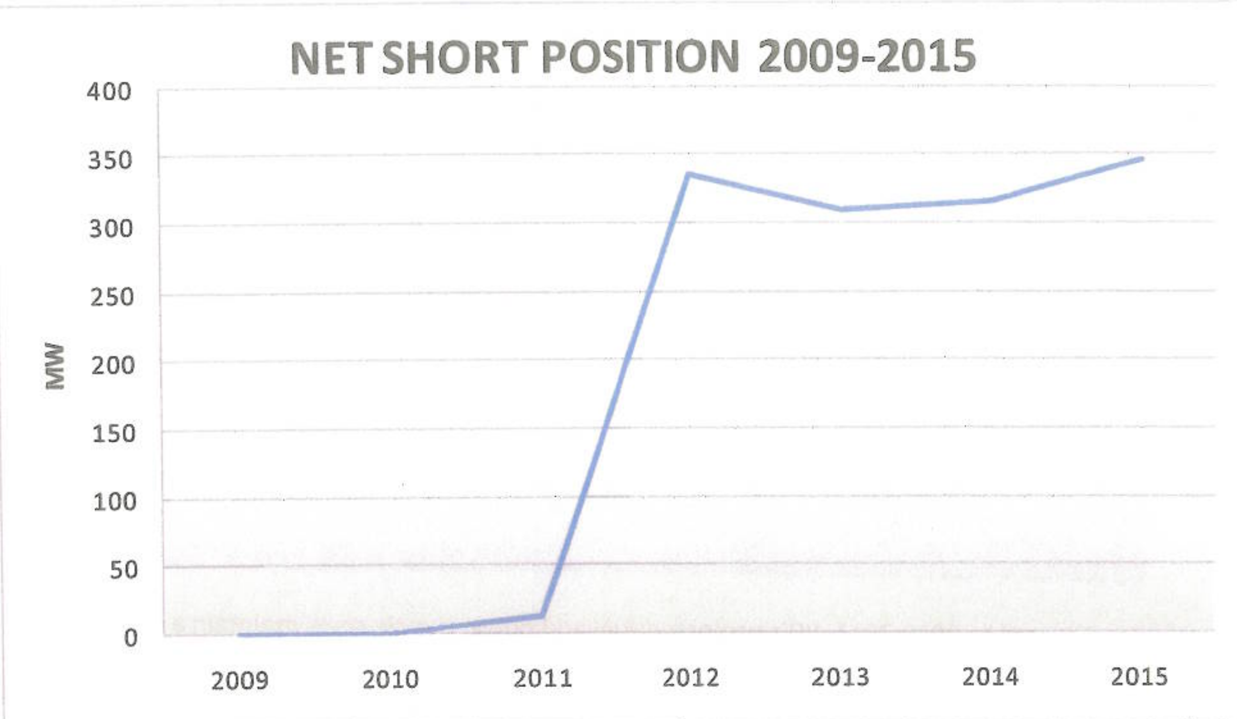
The expiration of these contracts by the summer of 2012 will leave the District short of capacity by an additional 250MW, not including the forecasted load growth and other unforeseen factors. Table 9.1 and Figure 9.1 below illustrate the affect of the expiring contracts on IID's net short position:

Table 9.1: Loads and Resources 2010-2015

SUMMARY OF IID'S ANNUAL PEAK DEMAND LOAD AND RESOURCES (MW) FOR 2010 AND BEYOND

FLEXIBLE RESOURCES BASELINE PLAN	2010	2011	2012	2013	2014	2015
TOTAL SYSTEM CAPACITY REQUIREMENTS	1145	1162	1185	1209	1233	1263
EXISTING DSM PROGRAM CAPACITY	31	50	51	51	51	51
DISTRICT-OWNED RESOURCES AND PURCHASES						
BRAWLEY	0	0	0	0	0	0
EL CENTRO 3	40	40	40	40	40	40
EL PASO	0	0	0	0	0	0
484 CONTRACTS	150	150	50	50	50	50
MORGAN STANLEY (EPE Replacements)	100	100	0	0	0	0
SHELL (EPE Replacements)	50	50	0	0	0	0
ALL EXISTING SUMMER CAPACITY	1014	1014	764	764	764	764
RESOURCE ADDITIONS						
1 Year PPA Summer Contracts	100	75				
GreenHunter		15	15	15	15	15
Solar/Wind (rfp 693)		20	20	20	20	20
Geothermal				50	67	67
TOTAL NEW RESOURCE ADDITIONS	100	110	35	85	102	102
TOTAL RESOURCES with DSM	1145	1174	850	900	917	917
NET SHORT POSITION	0	12	(335)	(309)	(316)	(346)

Figure 9.1: Net Short Position



Clearly, the procurement of capacity is critical to covering the District's capacity deficit and meeting the WECC standard 15 percent planning reserve criteria.

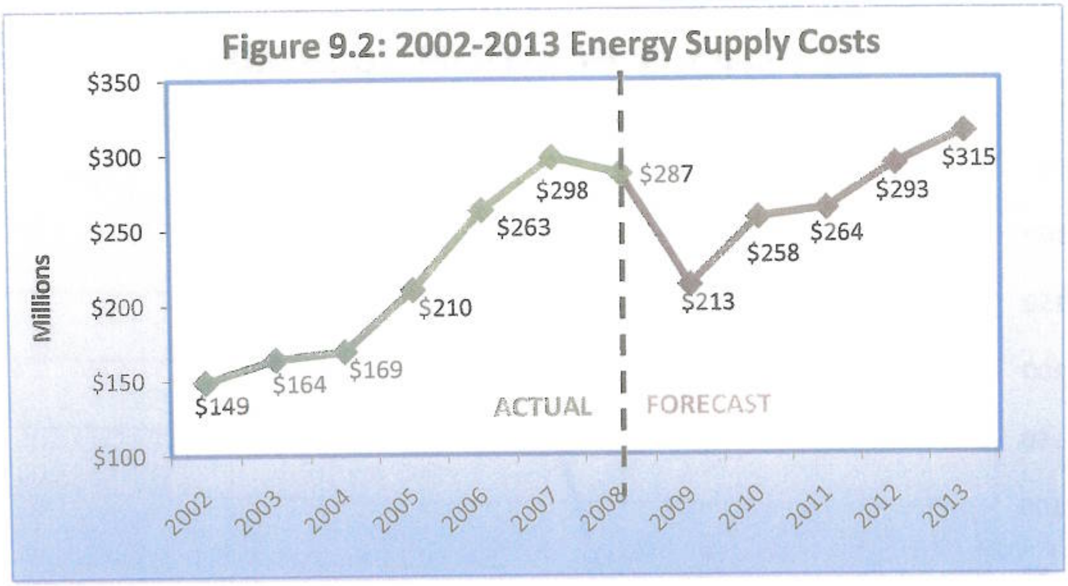
2009 Through 2011 Power Supply Costs

The District has acquired almost all the necessary resources to meet its 2010 and 2011 retail energy requirements. The District has also completed hedging its 2010 natural gas requirements (up to 70 percent of monthly requirements) and has begun hedging 2011 requirements.

The District's decision to retire the Brawley combustion turbines has resulted in a slight shortfall of capacity for 2011 that has not yet been met. In 2010 the District will purchase an additional 40 MW of summer peaking capacity to meet 2011 requirements.

Significant fluctuations of gas/energy market drivers have proved to be fundamental to price direction, and thus cost direction of energy consuming utilities. Market drivers include such items as local/regional/national weather and demand, alternative fuel substitutes (LNG, Shales), oil and natural gas storage, coal supply/demand, producing oil rigs, foreign policy, domestic regulation and many other obstinate forces.

Figure 9.2 presents the District's power supply costs for 2002 through 2013.



Looking forward to 2010-2011, IID's projected fuel and power supply costs maintain a steady incline mainly due to escalating market prices for energy and natural gas. IID's ongoing hedging program for 2010-11 continues to function as a rate stabilization instrument fixing a portion of natural gas expenses and reducing IID's exposure to volatility risk.

By 2012, IID expects to repower El Centro #3 to a unit providing increased fuel burning efficiency and notably decreasing variable costs. Furthermore, as mentioned throughout this document, IID will be obtaining additional resources necessary to meet load requirements while simultaneously complying with regulatory policies such as AB32 and the state RPS requirements.

These new resources will allow IID to depend less on the shifting gas/energy market resources while stabilizing costs and reducing volatility in customer energy bills as we proceed to 2010 and beyond.

2010-11 Budget Risk Management

The 2010-11 forecasted budgets are forecasted to be approximately $260 million. These budgeted power supply costs are based upon current forward energy prices that are embedded in the underlying assumptions. The fundamental objective of using risk management instruments is to reduce the uncertainty of price fluctuations and manage the risk of unforeseen budgetary vacillations. The District has worked to reduce these uncertainties with risk management instruments such as hedging future energy/natural gas short positions and capping costs with call options.

The District measures its exposure to risk using the Value at Risk (VaR) approach. This method estimates the impact of changes in major underlying variables on expected power supply costs. In order to measure this value at risk, several key aspects critical to budget forecasting must be assumed including:

- Energy prices
- Natural gas prices
- Load forecast
- Supply side short position (natural gas and energy)
- Market Trading hub volatility (based on historical trends)

Even though varying market trends will cause the District's entire resource stack to optimize differently, a short position of supply resources (natural gas and energy) must be assumed to measure the value at risk in the fuel and purchased power budget. The District uses a monte carlo, stochastic production cost model to project these resource positions based on load. With these assumptions, the IID fuel and purchased power budgetary value at risk can be quantified based on the above assumptions. Below is a table that demonstrates the 2010 value at risk as of 11-20-09:

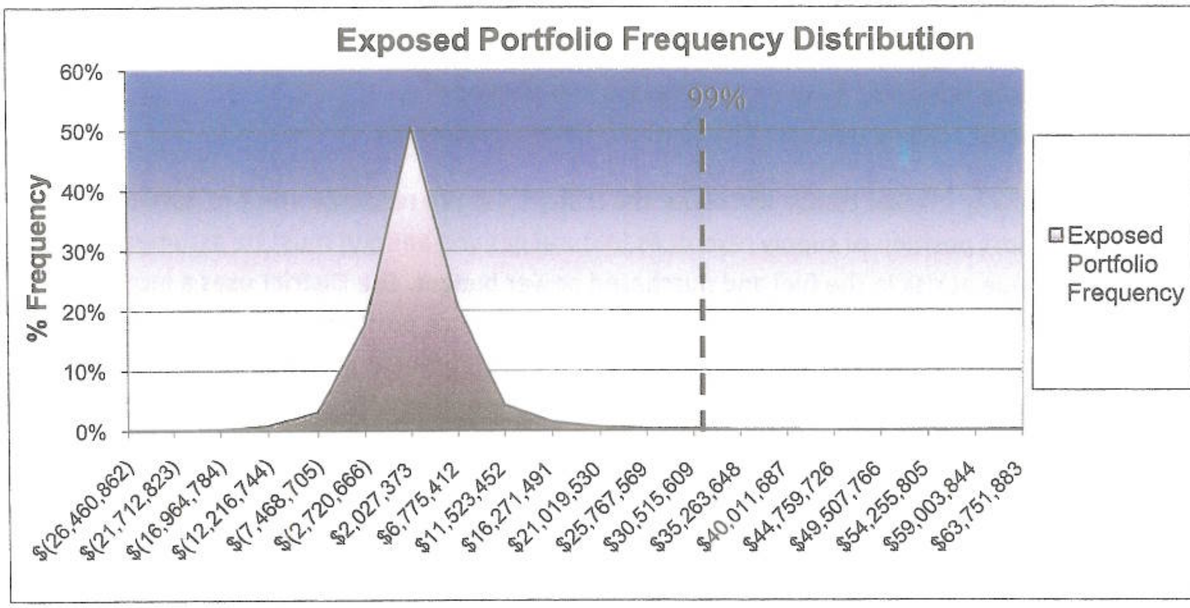
TABLE 9.2:

2010 HISTORICALLY BASED VALUE AT RISK						
Confidence Level	99%					
Metric	Native	Yucca	EPE	Spot Mkt Purchases	HR Call Options	Exposed Portfolio (mmBtus)
Volumetric Exposures (Short Position)	(1,553,082)	(3,226,022)	(191,487)	(635,189)	3,320,178	(8,925,958)
Budgeted Prices	$ 6.03	$ 5.57	$ 5.57	$ 46.16	$ 6.03	
Exposures ($)	$ 9,367,673	$ 17,952,812	$ 1,065,625	$ 29,322,534	$ 20,026,207	$ 77,734,852
VaR	$ 2,373,665	$ 3,895,758	$ 231,241	$ 9,216,064	$ 5,074,420	$ 19,532,649
Expected Shortfall	$ 3,005,707	$ 4,978,348	$ 295,500	$ 15,746,018	$ 6,425,600	$ 23,599,169

The above table displays the short position for each budget item of exposure and the corresponding value at risk. Essentially, the VaR for each portfolio item indicates the cost exposures or the probability of exceeding the original budget amount at a 99% level of confidence. In this case, if the historical volatility were to continue in 2010 with a similar trend, the District's budget has $19.5 million value at risk. In other words, if the market were to go up significantly, the fuel and purchased power budget will be $19.5 million higher than the original budget. The expected shortfall is a risk metric showing if conditions get excessively expensive in the market (such as Hurricane Katrina), then the District's expected short fall is the potential value that exceeds the budget. The expected shortfall is an additional statistical function that focuses on the extreme tails of the probability distribution (i.e, the remaining 1 percent of probability). VaR, on the other hand, illustrates the how bad things can get but focuses on 99 percent of the centered data.

A graphical representation of the above table in the graph below:

Figure 9.3:



The graph above shows the simulated probability of the budget value at risk. As in the table above, this graph illustrates 99 percent of the probable outcomes below $19.5 million. While the majority of the data is well below $19.5 million, the portfolio has the potential to be $19.5 million over the originally budgeted amount in a worst case scenario.

Higher risk is evident in 2011 with a total $29.3 million value at risk in fuel and purchased power supply budget in Table 9.3 below:

TABLE 9.3:

2011 HISTORICALLY BASED VALUE AT RISK						
Confidence Level	99%					
Metric	Native	Yucca	EPE	Spot Mkt Purchases	HR Call Options	Exposed Portfolio (mmBtus)
Volumetric Exposures (Short Position)	(4,822,886)	(3,627,004)	-	(805,200)	4,425,345	(13,680,435)
Budgeted Prices	$ 6.47	$ 5.96	$ 5.96	$ 47.20	$ 6.47	
Exposures ($)	$ 31,215,024	$ 21,622,989	$ -	$ 38,004,966	$ 28,642,031	$ 119,485,011
VaR	$ 7,909,543	$ 4,692,186	$ -	$ 11,944,950	$ 7,257,575	$ 29,364,871
Expected Shortfall	$ 10,015,638	$ 5,996,095	#DIV/0!	$ 20,408,430	$ 9,190,069	$ 37,894,443

The 2011 portfolio items are exposed to a potential of more extreme conditions mainly due to higher levels of short positions. The value at risk for the fuel and purchased power supply budget is $29.4 million at a 99 percent level of confidence. Furthermore, if an event or events were to occur to cause conditions to become extremely detrimental in the market, the expected shortfall (i.e., amount to exceed the budget) is $37.9 million.

Figure 9.4 below shows the frequency distribution of the exposed portfolio for 2011:

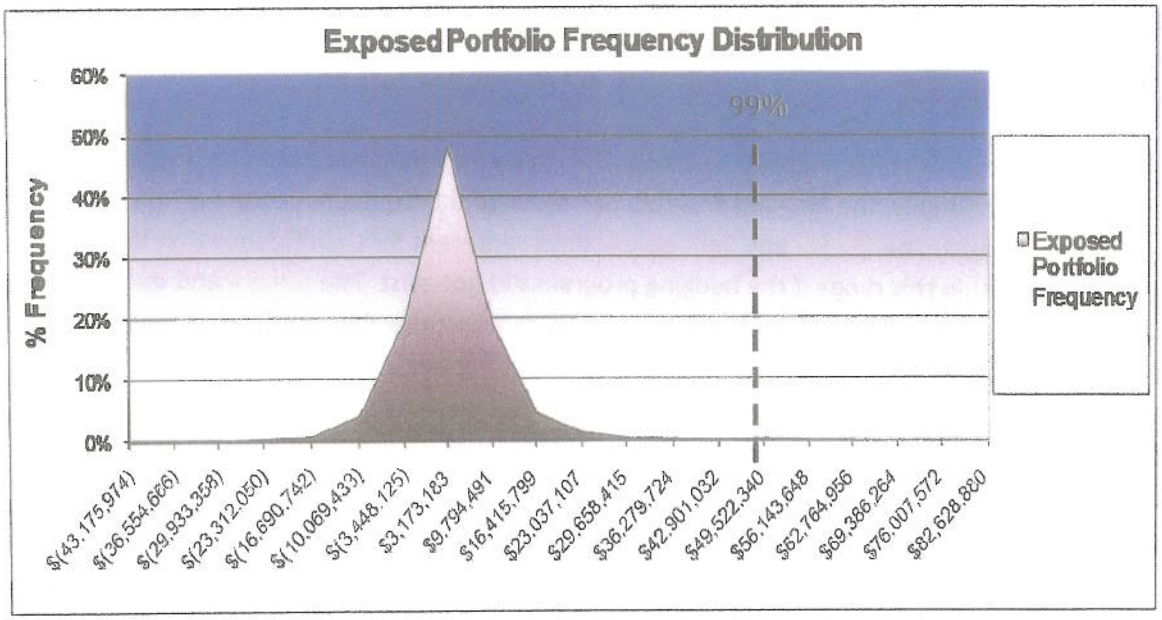


Figure 9.4

Once again, the above graph shows the value at risk of our budget to be $29.4 million at a 99 percent level of confidence. Compared to the 2010 frequency distribution of the IID exposed portfolio, the 2011 distribution depicts a wider range of potential outcomes (i.e., the budget cost variations show a broader gap between the high and low ranges of probable outcomes in 2011 than in 2010).

The method to manage and reduce the budget value at risk is hedging both energy and natural gas used to generate energy internally. Various hedging instruments used include energy strike price call options, heat rate call options, fixed price energy and gas purchases, costless collar (cap+floor), financial futures gas purchases, and blending and extending hedges to capture market reductions in price. Fundamentally speaking, the more hedged the greater of a reduction in budget value at risk. Hedging has reduced the 2010 budget at risk more than the 2011 budget at risk and we see the evidence for this in the 'Exposed Portfolio Frequency Distribution' graphs above.

Another easy way to view the budget value at risk reduction in 2010-11 is by observing the probability of potential outcomes in a 'Top-Down Value at Risk'. This perspective provides a glimpse of more than 1000 iterations of budget variations based on historical price volatility trends. When observed as a two tail (99 percent and 1 percent) test, the District's possible ranges of budget variations become very clear. Additionally, the risk reducing impacts of the District's hedging program are apparent as well. Without a hedging program, the District's short positions on budget items exposed to market price fluctuations are considerably greater than what they would be without a hedging program. Therefore, as the short position decreases, the District's budget portfolio achieves an increasingly narrow gap of risk exposure (i.e., lower budget value at risk).

As with the Value at Risk table (Table 9.3) above, the exposure values are based on historical price volatility. Essentially, the hedging program has reduced the exposure of the fuel and energy supply budget. The yellow and light purple lines represent 99% confidence that the budget will fall within this range if the hedging program **did not** exist. The orange and dark purple lines display the effects of the hedging program representing 99% confidence that the budget will fall within the range above. With the hedging program, the budget value at risk is reduced by about +/- $5 million. It is important to note that even though the confidence interval is 99 percent (two tails), there is still a probability that the budget could vary outside of the above ranges due to an extreme unforeseen event (e.g., Hurricane Katrina).

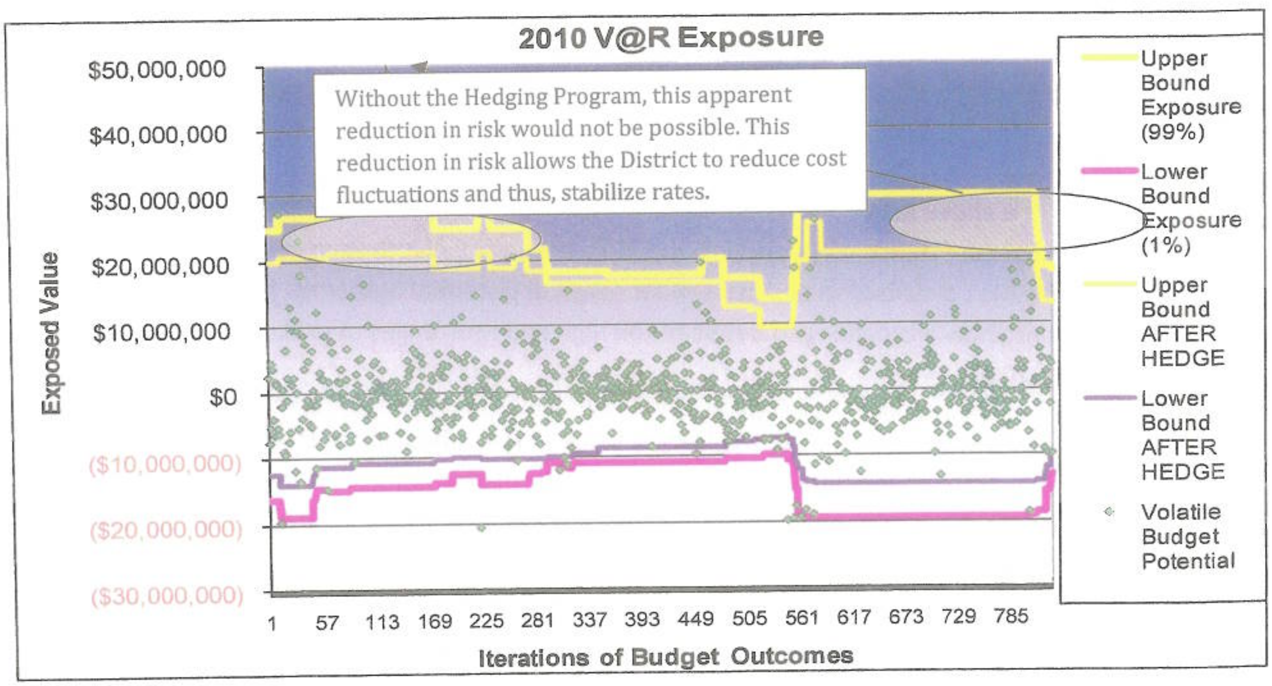


Figure 9.5

The 2011 Value at risk tells a similar story, except the range is broader due to the fact that there is less hedged in that year leaving a more short position exposed to the volatile market. This observation is evident in Figure 9.6 below:

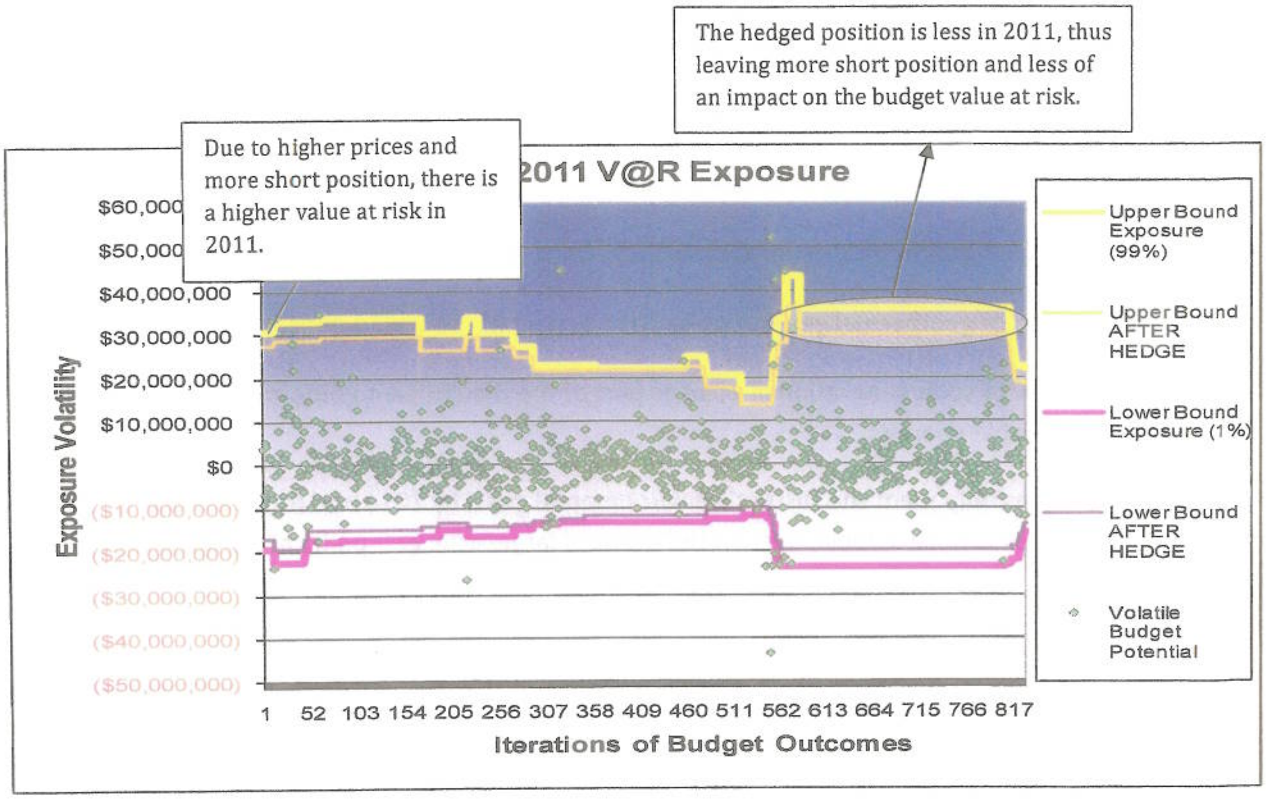


Figure 9.6

The Resource Planning Section is working towards minimizing the risk of budget deviation through careful planning and prudent decision making with the goal of stabilizing or reducing rates.

Analysis and Financial Impact Beginning in 2012

The short position in 2012 has been a major concern to the District for several years. Initially, the District issued an RFP (RFP #484) several years ago to cover the 2010-12 and earlier capacity deficits. The most viable option at that time was to repower EC3 by 2009. The project was delayed and therefore a subsequent RFP (#618) was issued to re-evaluate the repowering of EC3 and to cover a portion of the 2011-12 short positions. Once more, the final outcome resulted in repowering EC3.

Renewable Resources

The District will add a number of renewable resources in 2013 and 2014 both to meet GHG emission reduction standards and renewable portfolio standards as well as achieve greater price stability. While renewable resources are currently more expensive than fossil fuel fired generation, the escalation rate of renewable energy costs is low and known.

The renewable resources included in the various power supply cost simulations include:

- 15 MW of biomass generation in 2011 from the Greenhunter PPA;
- 50 MW of geothermal generation in 2013 from the District's on-going negotiations;
- 17 MW of geothermal generation in 2014 as part of the SCPPA geothermal project;
- 20 MW of solar generation in 2013 as part of the District's on-going negotiations for renewable energy.

These resources help meet the District's environmental goals by 2014 and provide a way of insuring long-term price stability even in the event of large-scale geo-political disruptions in the world.

Power Supply Simulations

The Resource Planning group tested several portfolios though the economic simulation of the current IID system. Each portfolio maintained the same gas/energy price forecast, load forecast, and system characteristics. Different resource sets were simulated over 20 years comparing the EC3 repowering project to offers from that time. The portfolios tested include:

- Baseline Run – All current resources with the addition of 100MW of seasonally shaped PPAs by 2012 and continuing operation of the existing El Centro #3.
- El Centro #3 Repowered – All current resources with the addition of 144MW of combined cycle generation by 2012 while decommissioning the original El Centro #3.
- La Rosita (Shell) – All current resources with the addition of 100MW of AGC/regulation accommodating capacity by 2012 coming from South of the Border via the La Rosita Plant. The existing El Centro #3 plant continues operations in this simulation
- North Branch Resources – All current resources with the addition of 100MW of AGC/regulation accommodating capacity by 2012 coming from Mexico and continuing operation of the existing El Centro #3.

- Green (Geothermal) – All current resources with the addition of 100MW of geothermal capacity (assuming current geothermal offer prices) by 2012 and continuing operation of the existing El Centro #3.

All portfolios sustain a net impact of 100-104MW of capacity added to the simulated system. This allows confidence in validity of the results tested. The following table exhibits the results from these runs:

As illustrated in Table 9.4, the El Centro #3 Repowering project is ranked the least-cost portfolio from both the ten-year planning year perspective and the twenty-year year perspective when compared to the economics of other alternatives.

Figure 9.6 demonstrates the projected savings in Average $/MWh of the IID System by adding EC3 to the resource mix:

The economic benefits from repowering El Centro come from a combination of its low heat rate of 7,400 mmBtu/kWh and its fairly low capital cost which is equivalent to a capacity charge of $8.88/kW-month assuming 30 year financing at a 4.5 percent interest rate. Additionally, these calculated benefits do not include the following positive externalities (which were not calculated in this analysis):

- Reduced emissions (due to the low heat rate) for AB 32 compliance;
- Improvement of internal infrastructure;
- Increased ancillary service reliability for future 3rd party regional development;
- Decrease of future reliance of expensive and high risk ISO imported power;
- Greater overall system flexibility;

The Yucca plant would be used more as a baseload resource rather than a regulating resource.

Table 9.4: 20 Year Portfolio Simulation Results

OVERALL SUMMARY OF ALL RUNS

	Year	EMISSIONS	ANNUAL PEAK NET SHORT POSITION (MW)[3]	% of MUST TAKE ENERGY	% of GREEN ENERGY	TOTAL VARIABLE COST ($000)[1]	TOTAL COST ($000)[2]	AVG $/MWh
	ANNUAL SUMMARY OF RUN 2 - NO EC#3 REPOWERED[4]							
1. NO EC#3 REPOWERED	2012	1,710.29	(335)	32.9%	10.8%	$ 249,662.42	$ 294,662.42	$ 73.39
	2013	1,909.26	(309)	35.5%	17.1%	$ 268,176.11	$ 314,801.11	$ 76.90
	2014	1,899.58	(316)	37.2%	25.6%	$ 302,796.79	$ 351,087.42	$ 84.12
	2015	2,002.45	(346)	37.4%	25.4%	$ 327,857.11	$ 377,855.00	$ 88.80
	2016	2,063.15	(378)	36.8%	25.0%	$ 356,650.19	$ 408,398.03	$ 94.13
	NPV 10 YR					$2,774,708.48	$3,187,538.02	
	NPV 20 YR					$5,416,859.52	$6,163,725.20	
	ANNUAL SUMMARY OF RUN 1 - EC#3 REPOWERED							
2. EC#3 REPOWERED	2012	2,413.63	(231)	32.9%	10.8%	$ 248,256.04	$ 293,256.04	$ 73.04
	2013	3,035.53	(205)	35.5%	17.1%	$ 267,922.98	$ 314,547.98	$ 76.84
	2014	2,913.18	(212)	37.2%	25.6%	$ 301,190.72	$ 349,481.34	$ 83.74
	2015	2,990.38	(242)	37.4%	25.4%	$ 323,136.20	$ 373,134.09	$ 87.69
	2016	3,060.54	(274)	36.8%	25.0%	$ 350,385.70	$ 402,133.54	$ 92.69
	NPV 10 YR					$2,725,879.66	$3,138,709.20	
	NPV 20 YR					$5,294,925.63	$6,041,791.30	
	ANNUAL SUMMARY OF RUN 3 - NO EC#3 rpwrd W/LA ROSITA							
3. LA ROSITA	2012	1,797.13	(235)	32.9%	10.8%	$ 250,178.43	$ 295,178.43	$ 73.52
	2013	2,004.62	(209)	35.5%	17.1%	$ 271,346.67	$ 317,971.67	$ 77.68
	2014	1,967.34	(216)	37.2%	25.6%	$ 305,977.10	$ 354,267.73	$ 84.88
	2015	2,044.62	(246)	37.4%	25.4%	$ 328,901.32	$ 378,899.21	$ 89.04
	2016	2,109.27	(278)	36.8%	25.0%	$ 357,200.69	$ 408,948.52	$ 94.26
	NPV 10 YR					$2,778,429.76	$3,191,259.31	
	NPV 20 YR					$5,417,964.90	$6,164,830.58	
	ANNUAL SUMMARY OF RUN 4 - NO EC#3 rpwrd W/NORTH BRANCH							
4. NORTH BRANCH	2012	1,899.46	(235)	32.9%	10.8%	$ 250,790.05	$ 295,790.05	$ 73.67
	2013	2,037.69	(209)	35.5%	17.1%	$ 272,948.69	$ 319,573.69	$ 78.07
	2014	2,020.17	(216)	37.2%	25.6%	$ 307,633.83	$ 355,924.45	$ 85.28
	2015	2,127.01	(246)	37.4%	25.4%	$ 331,299.35	$ 381,297.24	$ 89.61
	2016	2,210.35	(278)	36.8%	25.0%	$ 360,712.81	$ 412,460.65	$ 95.07
	NPV 10 YR					$2,800,023.46	$3,212,853.00	
	NPV 20 YR					$5,458,764.15	$6,205,629.83	
	ANNUAL SUMMARY OF RUN 5 - NO EC#3 rpwrd W/GREEN GEO							
5. GREEN	2012	1,751.30	(235)	43.0%	22.0%	$ 278,912.05	$ 323,912.05	$ 80.68
	2013	1,761.92	(209)	65.0%	44.4%	$ 318,282.59	$ 364,907.59	$ 89.14
	2014	1,784.67	(216)	66.1%	47.0%	$ 346,543.06	$ 394,833.68	$ 94.60
	2015	1,864.33	(246)	65.8%	46.4%	$ 369,226.66	$ 419,224.55	$ 98.52
	2016	1,922.40	(278)	64.7%	45.6%	$ 396,541.41	$ 448,289.25	$ 103.33
	NPV 10 YR					$3,089,655.77	$3,502,485.31	
	NPV 20 YR					$5,955,893.78	$6,702,759.46	

Notes:

1. Total Variable costs do not include some costs from SJ3, PV, WAPA, and others, But it does include fixed capacity charges.

2. Total Costs include Variable Costs + Fixed costs estimated at $65m escalated @ 2.5%/year.

3. Existing Resources included the following for all runs: 50MW of Geothermal by 2013, 20MW of Solar by 2013, and 17MW of LADWP Geothermal by 2014.

4. Run 1 does not include any of the studied additions, but does assume that the 100MW of additional capacity will be filled with PPAs.

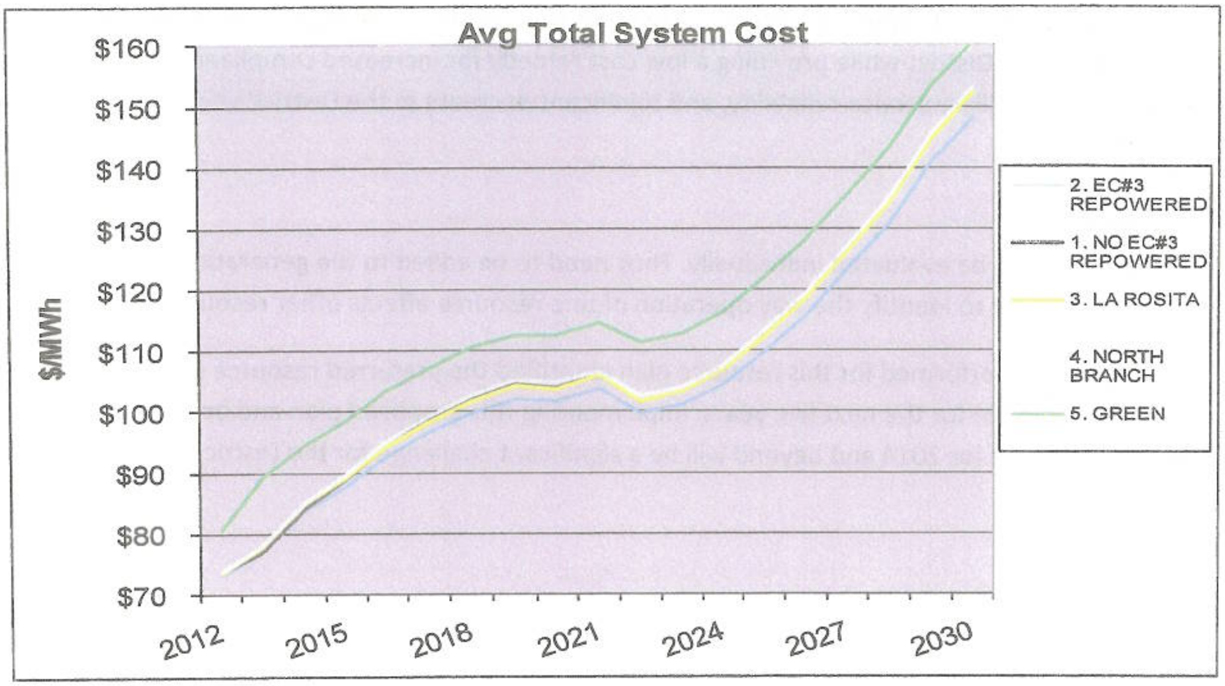


Figure 9.6: 20 Year Average System Cost

With the addition of the repowered EC3, IIDs short position will decrease by 104 MW as displayed in the table and chart below:

Table 9.5: Loads and Resources 2010-2015 with EC3 Repowering

SUMMARY OF IID'S ANNUAL PEAK DEMAND LOAD AND RESOURCES (MW) FOR 2010 AND BEYOND							
FLEXIBLE RESOURCES BASELINE PLAN	2009	2010	2011	2012	2013	2014	2015
TOTAL SYSTEM CAPACITY REQUIREMENTS	1109	1145	1162	1185	1209	1233	1263
EXISTING DSM PROGRAM CAPACITY	0	31	50	51	51	51	51
DISTRICT-OWNED RESOURCES AND PURCHASES							
BRAWLEY	18	0	0	0	0	0	0
EL CENTRO 3	40	40	0	0	0	0	0
EL PASO	145	0	0	0	0	0	0
484 CONTRACTS	150	150	150	50	50	50	50
MORGAN STANLEY (EPE Replacements)	0	100	100	0	0	0	0
SHELL (EPE Replacements)	0	50	50	0	0	0	0
ALL EXISTING SUMMER CAPACITY	1027	1014	974	724	724	724	724
RESOURCE ADDITIONS							
1 Year PPA Summer Contracts	81	100	75				
GreenHunter			15	15	15	15	15
Solar/Wind (rfp 693)			20	20	20	20	20
Geothermal					50	67	67
El Centro 3 Repower				144	144	144	144
TOTAL NEW RESOURCE ADDITIONS	81	100	110	179	229	246	246
TOTAL RESOURCES with DSM	1108	1145	1134	954	1004	1021	1021
NET SHORT POSITION	(0)	0	(28)	(231)	(205)	(212)	(242)

The decision to repower El Centro 3 appears to be the most economically viable decision, as demonstrated above. El Centro 3 provides a solution that results in the lowest cost and least emissions for the District while providing a low cost remedy for increased compliance, strengthened ancillary service reliability, and significant decrease in the District's net short position.

SUMMARY

Resources cannot be evaluated individually. They need to be added to the generation mix and evaluated as a set to identify the way operation of one resource affects other resources.

The simulations performed for this resource plan identified the preferred resource expansion plan for the District for the next five years. Implementing this proposed plan and beginning to identify resources for 2014 and beyond will be a significant challenge for the District.

Chapter 10: Effects of Proposed New Resource Plan

Introduction

In the prior chapter, power supply cost simulations were performed to identify the least-cost resource mix. This chapter examines unresolved issues that impact power supply costs, the impact on regulatory requirements of the preferred resource set and implications for long-term cost stability.

The preferred resource mix, which includes the repowering of EC3, 65 MW of geothermal generation, 20 MW of solar generation and 18 MW of biomass generation, is sufficient to meet most of the District's goals through 2014. Power purchase agreements will be used to meet any remaining monthly capacity or energy deficits. The District will also begin taking advantage of opportunities to stabilize future power supply costs, such as hedging natural gas costs.

Yucca Plant

Gas purchases for the Yucca Plant are one of the District's largest unhedged liabilities. Under the current operating agreement with APS, APS purchases all gas requirements for the plant and then charges the District actual burner-tip costs. The District uses financial hedges in an attempt to reduce the price volatility associated with APS' gas purchases but can only reduce a portion of the volatility because it does not know what APS is paying for the gas or the actual amount of gas that will be used by the Yucca Plant on a daily basis.

The Yucca Plant uses between 6,000 and 10,000 MMBTU of gas per day although it has exceeded daily use of 15,000 MMBTU several times in the past three years.

Currently, all gas used by the Yucca Plant is transported through the El Paso pipeline to an existing Yuma lateral pipeline. APS owns all the capacity on the Yuma lateral. APS is constructing two new generating stations that will receive natural gas supplies from the Yuma lateral. When these new generating plants begin operating, the Yuma lateral will not have sufficient capacity to meet the daily gas requirements of APS' generating plants and the Yucca Plant.

From a contractual basis, APS probably cannot force the District to acquire new gas transportation services although it can terminate the existing gas services agreements with sufficient notice.

A new gas transmission line is currently being constructed by TransCanada that will be able to supply gas to the Yucca Plant. This new line, the Baja Norte line, interconnects with the El Paso interstate pipeline at Ehrenberg and then goes south into Mexico where it interconnects with another new transmission line at Ogilby Pressure Station. The line then goes east to the Mexican-Arizona border and then to the Yucca plant.

Operating a generator used for generation off an interstate pipeline is difficult. Gas purchases and gas burn must be approximately equal (within ten percent) on an hourly, daily and rolling seven day period to avoid imbalance penalties from the pipeline owner. In this case, the District can easily balance on a daily and rolling seven day basis, but will have difficulty in balancing on an hourly basis. This difficulty is due to how the District uses the Yucca Plant. Rather than schedule the plant and operate it according to the daily schedule, the Yucca Plant is used for regulation on the District's system. This means that hourly burns cannot be forecasted.

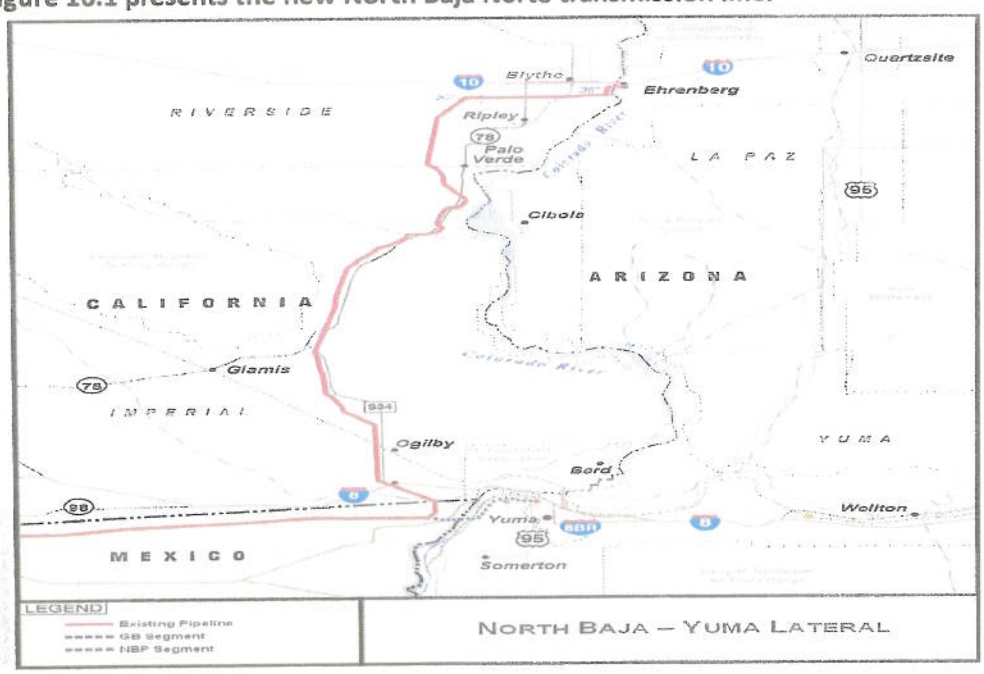
There are ways that the District can schedule gas to avoid imbalance penalties although these result in higher transportation costs.

The District must also pay for interconnecting the new line with the Yucca Plant, a cost estimated at around $3,500,000 although the actual cost could be higher or lower than this.

The issues that the District is dealing with can be summarized rather simply. Can the District reduce or stabilize its natural gas costs by switching to a new pipeline and taking responsibility for gas supplies?

The District can achieve price stability using financial hedges for gas supplies. It is yet unknown if the District can reduce gas costs for Yucca enough to justify the investment in infrastructure necessary to take service on the new transmission line.

Figure 10.1 presents the new North Baja Norte transmission line.



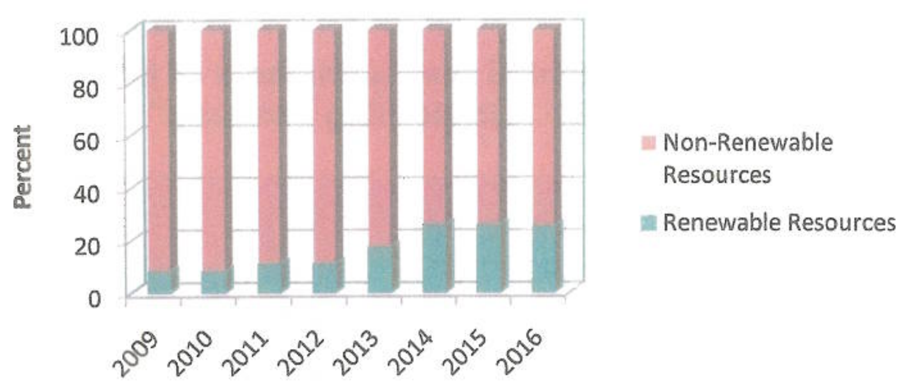
Renewable Portfolio Standards

As discussed in prior sections, the District is required to meet renewable portfolio standards (RPS) of 20 percent of retail load met by renewable resources by 2010, increasing to 33 percent by 2020. Currently, the District has roughly 8 percent of load met by renewable resources and is unlikely to meet the 20 percent obligation until 2013.

The only significant renewable resource likely to come on-line prior to 2012 is Greenhunter with 15 MW of capacity.

With the renewable resources anticipated by the District, the percentage of load met by renewable resources increases significantly beginning in 2013, as shown by Figure 10.2.

Figure 10.2: District's Renewable Resources



Yet even with the proposed 103 MW of renewable resources coming online within the next five years, the District is still short resources necessary to meet the 2020 RPS.

To meet the 30 percent standard by 2020, the District will need to add 15 – 25 MW of capacity every other year beginning in 2016 through 2020 if it uses wind or solar generation to meet future requirements. Another 30-40 MW of geothermal resources would also meet the District's energy needs, although the District would have excess baseload capacity in the future.

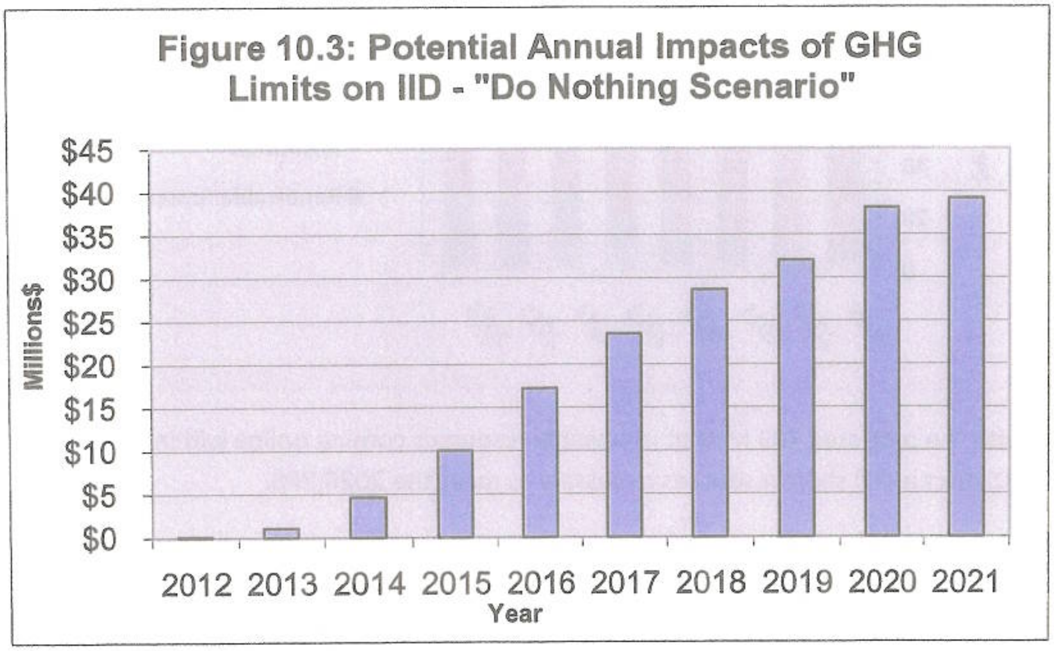
Greenhouse Gas Emission Standards

The District is still attempting to determine the possible impact of existing state and proposed federal GHG emission reduction legislative on future power supply costs. The District has used a model developed by LADWP to estimate the financial impacts of GHG emission restrictions. But, like much of the analysis currently being done, the analysis is heavily dependent upon assumptions about the way regulations will ultimately evolve.

The final rules governing California's GHG reduction efforts (AB 32) will not be finalized until October 2010, although a draft final report indicating how the California Air Resources Board (CARB) intends to implement AB 32 will be released in December 2009. The draft final report will be a good indication of the direction that CARB will follow in reducing utility-related GHG emissions.

California is at least one year ahead of the federal government in developing GHG reduction legislation. At this point, it appears that the District will be obligated to meet the most restrictive GHG emission regulations although some western states are lobbying to have federal standards preempt state standards.

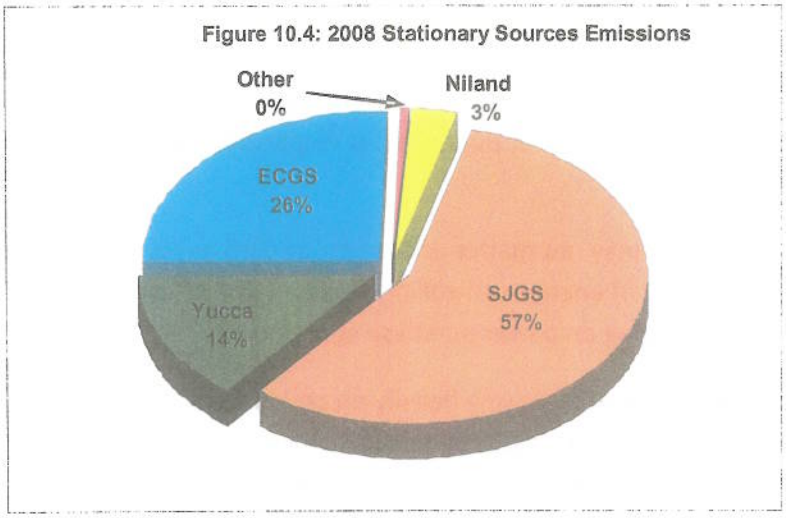
Using the draft plan prepared by CARB, the District has estimated its cost of meeting AB 32 standards. The analysis presented in Figure 10.3 assuming that the District did not begin acquiring renewable resources in 2013, shows that the District would have to start purchasing emission allowance credits in 2013 although significant financial impacts would not begin until 2014 and then increase significantly thereafter



Assumes $50/ton for emission allowances

The primary reason that the District exceeds annual GHG emission standards is its ownership in San Juan Generating Station, Unit 4 (SJGS). This is a coal-fired plant in New Mexico that has relatively high GHG per MWh of generation, approximately 2,400 lbs/MWh compared to the proposed standard of 1,100 lbs/MWh.

Figure 10.4 shows how SJGS impacts the District's total emissions of GHG.



Another issue that is being addressed by Southern California utilities is ownership of coal-fired generation. For a variety of reasons in the 1980's and 1990's, Southern California utilities began acquiring out-of-state coal resources as the least-cost resource alternative. The District acquired SJGS during this time period.

The District financed its purchase of SJGS through SCPPA. In 2020 the SCPPA bonds will be retired and the District's cost of ownership will decline by some $6,000,000 annually. However, the District will begin examining its continued ownership in SJGS in light of the potential GHG penalties associated with this plant.

It is possible that with the preferred resource mix of renewable resources and efficient generation, the District would want to maintain ownership of SJGS. However, if the District does not begin acquiring renewable resources and efficient natural gas fired generation, the additional costs of meeting GHG emission requirements might make SJGS unaffordable.

That is, because the District will be forced to reduce GHG emissions to 1,100 lbs/MWh on average, new renewable generation and high efficiency gas-fired generation can be used to reduce the District's GHG emissions to (or below) 1,100 lbs/MWh. If the District continues to acquire inefficient resources with high GHG emissions, it will have to purchase emission allowances for SJGS at a cost of around $25/MWh.[18]

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[18] Based upon $50/ton and SJGS emissions of 2,400 lbs/MWh

The District should begin examining alternatives to continued ownership of SJGS in 2020. These alternatives could include converting SJGS to a gas-fired facility or the possible sale of SJGS and purchase of 100 MW of other resources in 2020.

A significant unknown at this time is the way that the State or Federal rules will deal with power purchases. Which entity, the generator or purchaser, is responsible for GHG emissions and any associated penalties?

While from a cost viewpoint it may not matter as the cost of GHG emission allowances are likely to be included in the total cost of energy, controlling the level of GHG emissions will be easier for the District rather than relying on power purchase agreements.

That is, the District should not plan on relying heavily on power purchases in the future as energy costs will likely escalate as wholesale sellers begin including GHG costs in the price of power. Over reliance on wholesale purchases will likely result in higher costs to the District as opposed to generation from high efficiency and renewable resources that do not have carbon penalties associated with them.

Renewable Portfolio Standards

The District's planned renewable purchases in 2011 through 2014 result in approximately 25 percent of total retail energy sales being met by renewable resources. However, the District must still acquire another 5 percent of renewable generation (or approximately 300,000 MWh) of renewable energy by 2020. This is equivalent to 40 MW of baseload energy or around 135 MW of solar generation or some other intermittent resource such as wind with an annual capacity factor around 25 percent.

Typical load growth for the District is around 20 MW per year. So the District can anticipate purchasing 15 – 20 MW of renewable resources every other year, or roughly one-half of its annual purchases, to meet renewable requirements.

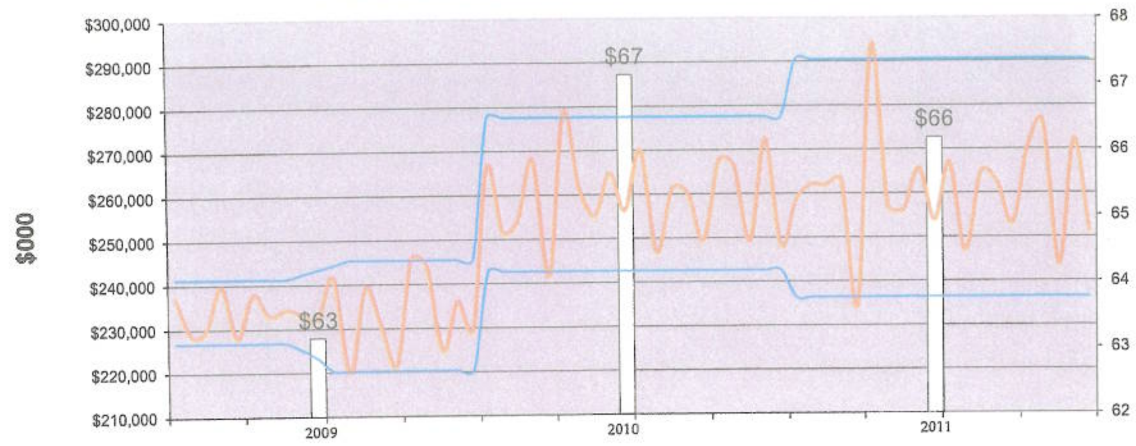
Long-Term Power Supply Cost Volatility

The District's Risk Management Plan requires that sufficient energy and natural gas supplies be hedged to insure that power costs do not increase by more than 10 percent in the prompt year (the next planning year), 20 percent prior to the beginning of the second planning year and 30 percent prior to the beginning of the third planning year based upon a \$2.00/MMBTU increase in natural gas costs.

Changes in natural gas costs affect not only the cost of energy from the District's internal generation but also the cost of purchased power, especially tolling agreements.

The following Figure 10.5 shows the District's expected range of power supply costs for 2009 through 2011 and the volatility of total power supply costs.

Figure 10.5: Est. Budget Parameters by Year



As the figure shows, it 2011 total power supply costs can vary by about $40 million annually ($20 million above or below the expected cost) based upon underlying factors such as gas costs, forecast errors and other variations in the future energy environment.

As the District begins acquiring new renewable resources to its generation mix, the volatility of power supply costs will begin to decline. Renewable resources may be expensive in comparison to prices today but in the long run renewable cap both power supply costs and overall volatility.