DOCKETED	
Docket Number:	18-IRP-01
Project Title:	Integrated Resource Plan
TN #:	227181
Document Title:	2017 Power Enterprise Integrated Resource Plan - Hetch Hetchy Power IRP - Attachment A
Description:	SFPUC's Hetch Hetchy Power's Integrated Resource Plan - This document is part of TN 227180-11 through TN 227180-6
Filer:	James E. Hendry
Organization:	San Francisco Public Utilities Commission
Submitter Role:	Public Agency
Submission Date:	2/27/2019 2:16:01 PM
Docketed Date:	2/27/2019

2017 POWER ENTERPRISE INTEGRATED RESOURCE PLAN

PREPARED FOR

San Francisco
Water
Power
Sewer

Services of the San Francisco Public Utilities Commission

San Francisco Public Utilities Commission

JULY 2017

BLACK & VEATCH
Building a world of difference.®

Assumptions and Limitations Disclaimer

This report was prepared for the San Francisco Public Utilities Commission (SFPUC) by Black & Veatch Corporation (Black & Veatch) and is based on some information not within the control of Black & Veatch. Black & Veatch has assumed that the information, both verbal and written, provided by others is complete and correct; however, Black & Veatch does not guarantee the accuracy of the information, data, or opinions contained herein.

Any information shared with SFPUC prior to the release of the report is superseded by this report.

Black & Veatch owes no duty of care to any third party, and none is created by this report. Use of this report, or any information contained therein, by a third party shall be at the risk of such party and constitutes a waiver and release of Black & Veatch, its directors, officers, partners, employees, and agents by such third party from and against all claims and liability, including, but not limited to, claims for breach of contract, breach of warranty, strict liability, negligence, negligent misrepresentation, and/or otherwise, and liability for special, incidental, indirect, or consequential damages, in connection with such use.

Table of Contents

LIST OF FIGURES

LIST OF TABLES

1.0 Executive Summary

This Integrated Resource Plan (IRP) is designed to serve as a roadmap that will guide future decisions about resources needed to meet future electricity demand for San Francisco Public Utilities Commission (SFPUC) customers, as well as decisions about how to best utilize existing energy supply resources. A long-range energy resource plan will assist SFPUC in continuing to provide affordable, reliable electricity to its customers. This plan is a crucial element for success in a constantly changing business and regulatory environment and will better position SFPUC to meet the challenges facing the electric utility industry.

Integrated resource planning is a formal process undertaken by a utility to determine future resource requirements necessary for meeting forecasted annual peak and energy demand, with an adequate reserve to provide for system reliability and integrity. Key steps include:

- *Forecasting future loads*
- *Identifying potential resource options to meet those future loads*
- *Receiving and responding to stakeholder participation*
- *Determining an optimal resource plan within the framework of key parameters and metrics that reflect the overall objectives of the planning process.*

The conditions and circumstances in which utilities must make decisions about how to meet customers' future electric energy needs are ever-changing. Decisions are influenced by the utility's existing generation portfolio, the costs and availability of different resource alternatives, and by changes in environmental regulations, commodity prices, technology advancements, and economic conditions at large.

This IRP examines options for operations of SFPUC's three hydroelectric facilities (Kirkwood Powerhouse [KPH], Holm Powerhouse [HPH], and Moccasin Powerhouse [MPH]) under a variety of scenarios. The following three main scenarios were evaluated:

- *Scenario 1 – Maintain Current Generation: All necessary investment to maintain the current level of generation through 2041.*
- *Scenario 2 – Delay Some Projects: Operation reflecting approved Capital Investment Plan (CIP) projects for Years 1 through 10, with unfunded needs delayed until Years 11 to 25 of the analysis.*
- *Scenario 3 – Defer Moccasin: Defer MPH and water conveyance projects throughout the study period.*

In addition to the three main scenarios, sensitivity analyses were performed to determine the impact of the following modifications:

- *Addition of renewable resources*
- *Meteorlogical uncertainty*
- *Market price uncertainty*
- *Increased load growth*

The overall net present value (NPV) was calculated for each scenario to define the impact of each option. This calculation was coupled with environmental impact, market risk profile, policy compliance, and other relevant factors to help inform the choices being made for future operation of the SFPUC electric generation and transmission system.

1.1 BACKGROUND AND METHODOLOGY

The basis for the system analysis was the PLEXOS production cost model. PLEXOS is industry standard, tried-and-true simulation software that uses state-of-the-art mathematical optimization combined with the latest data management, visualization and distributed computing methods to provide a high-performance, robust simulation system for electric power systems.

The analytics performed for this IRP examined the costs, environmental impacts, and reliability of each strategy. Validation of the methodology and execution of the model runs was accomplished through comparison of results with internal peer groups, manual spot checks, and discussions with SFPUC staff to verify the results. Modifications of modeling approaches and scenarios were performed as appropriate to ensure that the models adequately reflect the current state of SFPUC system operations and likely future operations scenarios.

Data for input to the PLEXOS model came from Working Groups (WGs) which addressed Cost Allocation, Generation, Transmission, Market Pricing, Load, and Policy (numbered 1 through 6, respectively). Each WG consisted of Black & Veatch leads and experts from the SFPUC's Power, Water, Finance, and Regulatory Affairs groups that focused on a group of inputs needed to appropriately model the SFPUC system; a summary of the staff involved in each WG can be seen in Appendix A. WGs worked closely to review the assumptions and collaborate on the best use of data for modeling purposes. This effort also developed a set of portfolios and sensitivities to be modeled using PLEXOS. The major data inputs from the WGs and models used to develop the results in this IRP can be seen below in **Figure 1-1**.

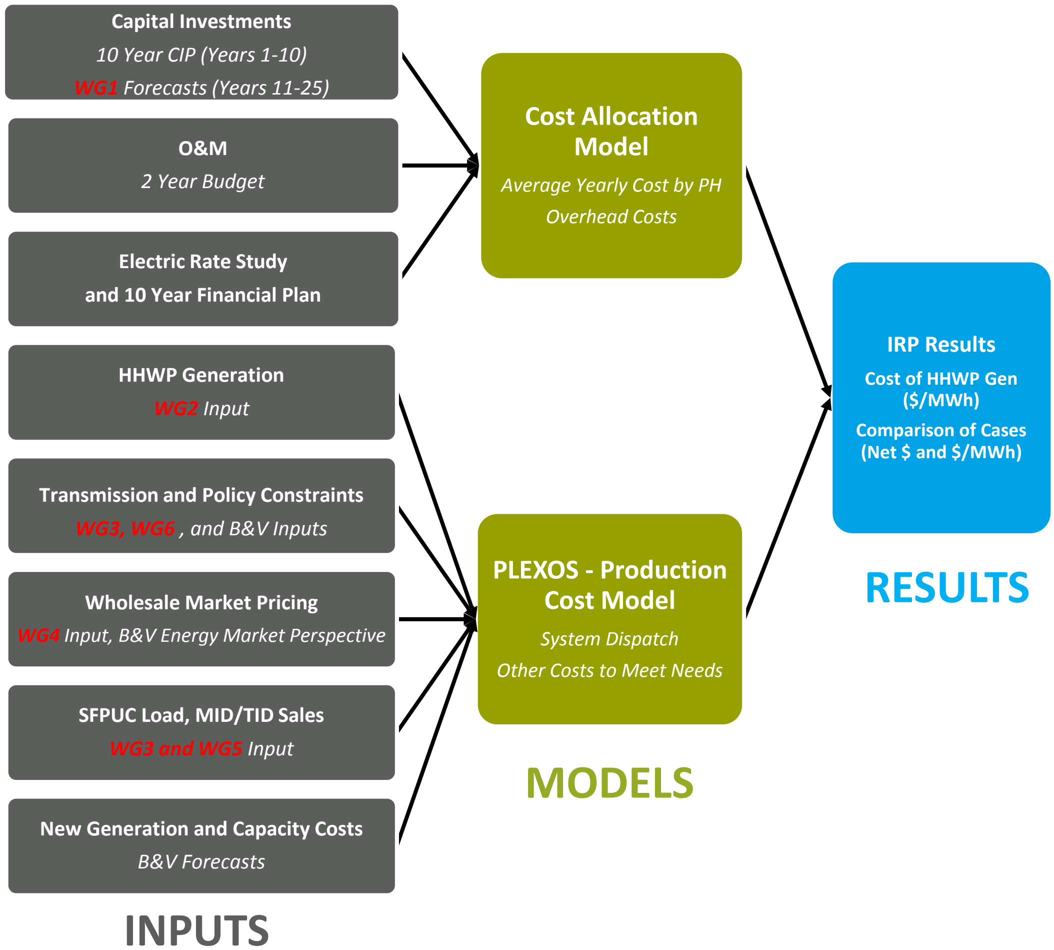

Figure 1-1 Approach to Data Collection and Usage

After the raw data from the PLEXOS model was downloaded, a "scorecard" was created to summarize the key items that affect the system NPV. To provide context for the hydroelectric generation units available to the SFPUC to meet load obligations, the level of generation available from each unit, and the cost by unit, a series of graphics was created that demonstrated how the SFPUC would preferentially dispatch to meet load for each scenario. Although this does not reflect how the SFPUC truly operates because it is a "water-first" utility, the graphics are useful to understand the cost effectiveness of each unit in meeting load; the use of graphics is consistent with how most electric utilities evaluate the economics of generation for IRP purposes.

The most critical input to the PLEXOS model were the assumptions used for the capital and operating costs for each of the hydroelectric generation units. The final assumptions developed by Working Group 1 for each of the three main analysis Scenarios are outlined in the tables below (**Tables 1-1 through 1-3**). Listed in these tables are both the cost of "generation only", which takes into consideration powerhouse specific equipment ("Unit Cost"), and the full cost of generation once Power Enterprise overhead costs are allocated to each powerhouse.

Table 1-1 Scenario 1 Investment by Powerhouse

POWERHOUSE	AVG. ANNUAL CAPITAL + O&M ($MM)	TOTAL EXPENDITURE ($MM)	GENERATION (GWH)	UNIT COST OF GENERATION ($/MWH)	COST OF GENERATION WITH OH ($/MWH)
HPH	13.4	321	16,607	19	36
KPH	8.7	208	13,357	15	37
MPH	31.7	761	8,985	84	113

Table 1-2 Scenario 2 Investment by Powerhouse

POWERHOUSE	AVG. ANNUAL CAPITAL + O&M ($MM)	TOTAL EXPENDITURE ($MM)	GENERATION (GWH)	UNIT COST OF GENERATION ($/MWH)	COST OF GENERATION WITH OH ($/MWH)
HPH	13.6	325	14,891	22	40
KPH	8.7	208	13,208	15	37
MPH	32.1	771	8,937	86	115

Table 1-3 Scenario 3 Investment by Powerhouse

POWERHOUSE	AVG. ANNUAL CAPITAL + O&M ($MM)	TOTAL EXPENDITURE ($MM)	GENERATION (GWH)	UNIT COST OF GENERATION ($/MWH)	COST OF GENERATION WITH OH ($/MWH)
HPH	16.1	386	14,891	26	45
KPH	12.9	310	13,202	23	50
MPH	0	0	1,319	--	

The reason for the considerably higher expenditure for Moccasin Powerhouse in Scenarios 1 and 2 is primarily due to two large capital investment projects: Mountain Tunnel Improvement Project ($616 million) and Transmission Lines 3/4 Capital Improvement Projects ($396 million).

It should be noted, that when considering near term capital and operating expenditures over the next two years, the cost of generation at Moccasin Powerhouse is roughly $73/megawatts per hour (MWh), including overhead costs. Holm and Kirkwood Powerhouses are roughly $20 and $25/MWh, respectively. ***The cost of power from Moccasin Powerhouse is currently significantly above the current market value.*** Current market value is $20-30/MWh based on average market prices (see Figure 1-6). Additional capital or operating costs associated with Moccasin will further exacerbate this condition both in the short and long-term. It should also be noted that the cost of Holm and Kirkwood are slightly under the average annual Market value; however in some months and hours they could also be above Market value particularly due to low market pricing in the Spring months.

Scenario 3 represents a scenario where Moccasin Powerhouse is deferred so the Mountain Tunnel Improvement Project, and Transmission Lines 3/4 Capital Improvement Projects are removed. Other major projects included in the analysis for all scenarios are the improvements to Cherry Reservoir ($204 million, allocated to Holm Powerhouse) and O'Shaughnessy Dam ($107 million, split between Moccasin and Kirkwood Powerhouses). Note that the cost of generation for Holm and Kirkwood increase in Scenario 3 due to a reallocation of some expenses to these powerhouses that were previously partially incurred by Moccasin.

1.2 RESULTS

Figure 1-2 shows the results for Scenario 1. Each stacked bar represents generation from the three hydroelectric units over the analysis period and the average cost of generation from each. The cost of generation and the overhead cost from each powerhouse are also shown.

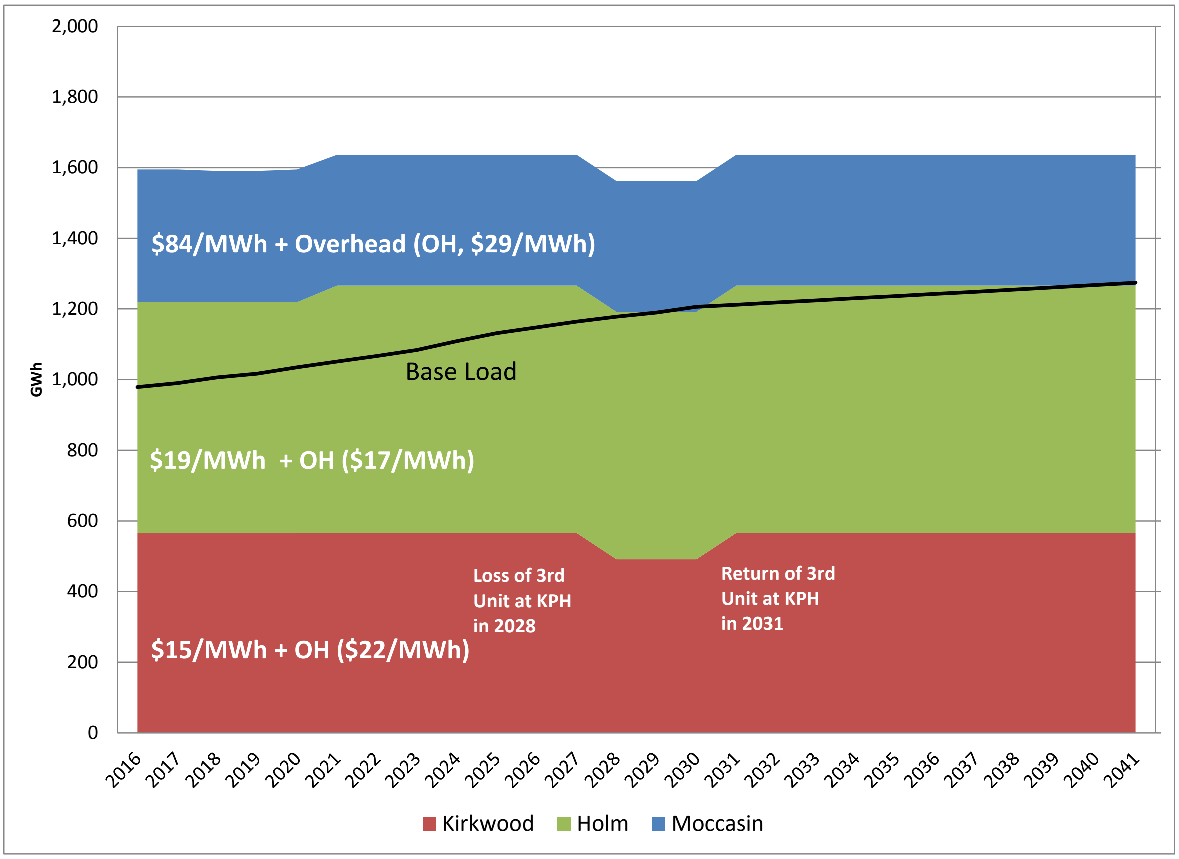

Figure 1-2 Scenario 1 Dispatch

Currently, the SFPUC is long in generation and a net exporter of power. This can be seen quite clearly from Figure 1-2, which shows that generation from KPH and HPH is sufficient to meet the average yearly base case load throughout the analysis period.

Any generation above that needed to meet load is sold in the CAISO market. While this is relatively economical for generation from KPH and HPH, (which have an average cost of generation of $15 to $19/MWh before overhead costs are added), generation from MPH is generally uneconomical for market sales.

The results from the dispatch analysis for Scenario 3 are shown on **Figure 1-3**.

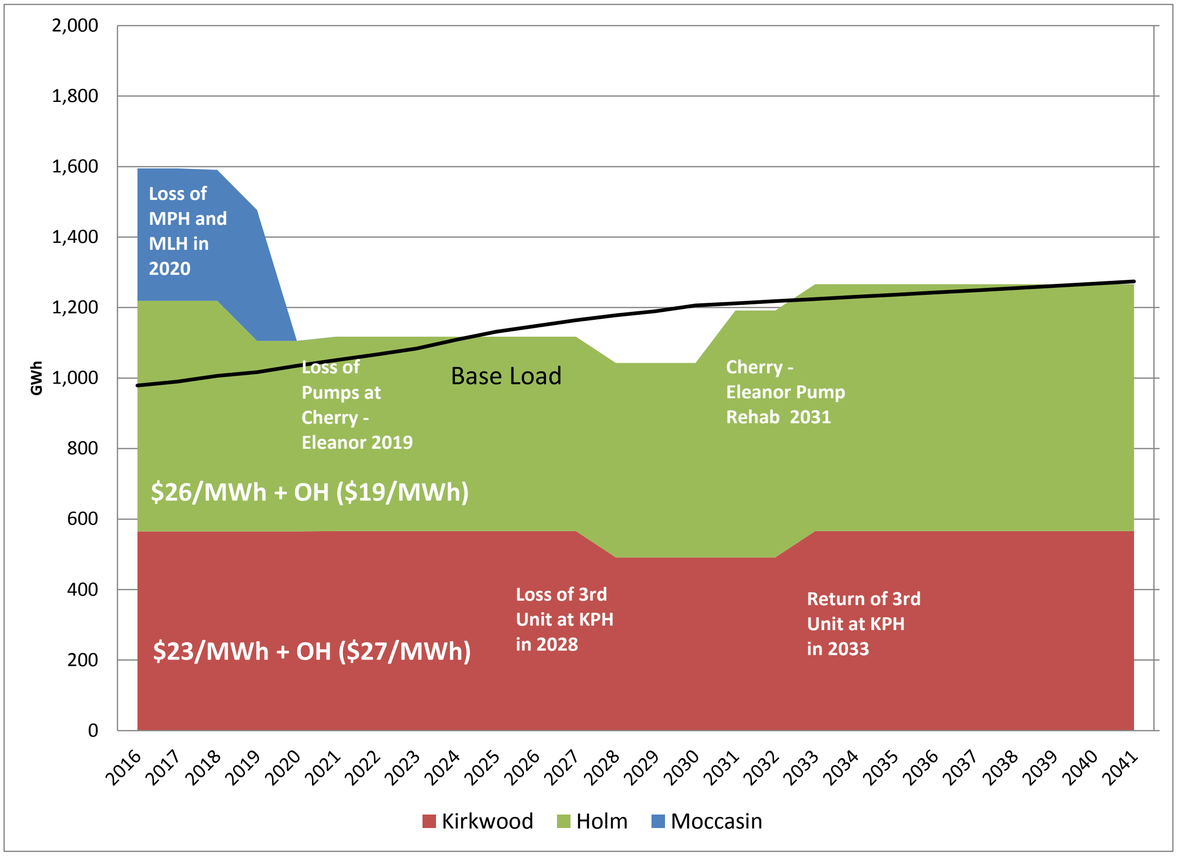

Figure 1-3 Scenario 3 Dispatch

Scenario 3 results in a reduction of generation levels such that power supply and demand are much closer to being balanced than in Scenario 1. Any generation shortages to meet load requirements are met through market purchases. The cost of generation for KPH and HPH in this scenario is higher than in the previous scenarios because the allocation of costs previously assigned to MPH is switched to the other Powerhouses.

Scenario 2 was found to be uneconomical relative to Scenarios 1 and 3 in all versions explored in the PLEXOS modeling. This scenario costs more than Scenario 1 (because the deferrals of capital investments lead to inefficient maintenance procedures) for less generation, leading to higher overall generation costs on a $/MWh basis. ***Therefore, for future case comparison and sensitivity analyses, only Scenarios 1 and 3 were compared.***

Figure 1-4 shows the NPV for Scenarios 1 and 3 categorized into four major areas: Capital Costs, O&M Costs, Net Wholesale Market Revenues, and Other Costs, which entails costs to Power Enterprise that are largely unchanged regardless of the case. Capital and O&M costs to Power Enterprise are $342MM higher in Scenario 1; while Scenario 1 also has higher market revenues of $264MM over the analysis period, this revenue is not enough to offset the additional expenditures. Taking all these items into account, Scenario 3 has an NPV that is $78MM lower.

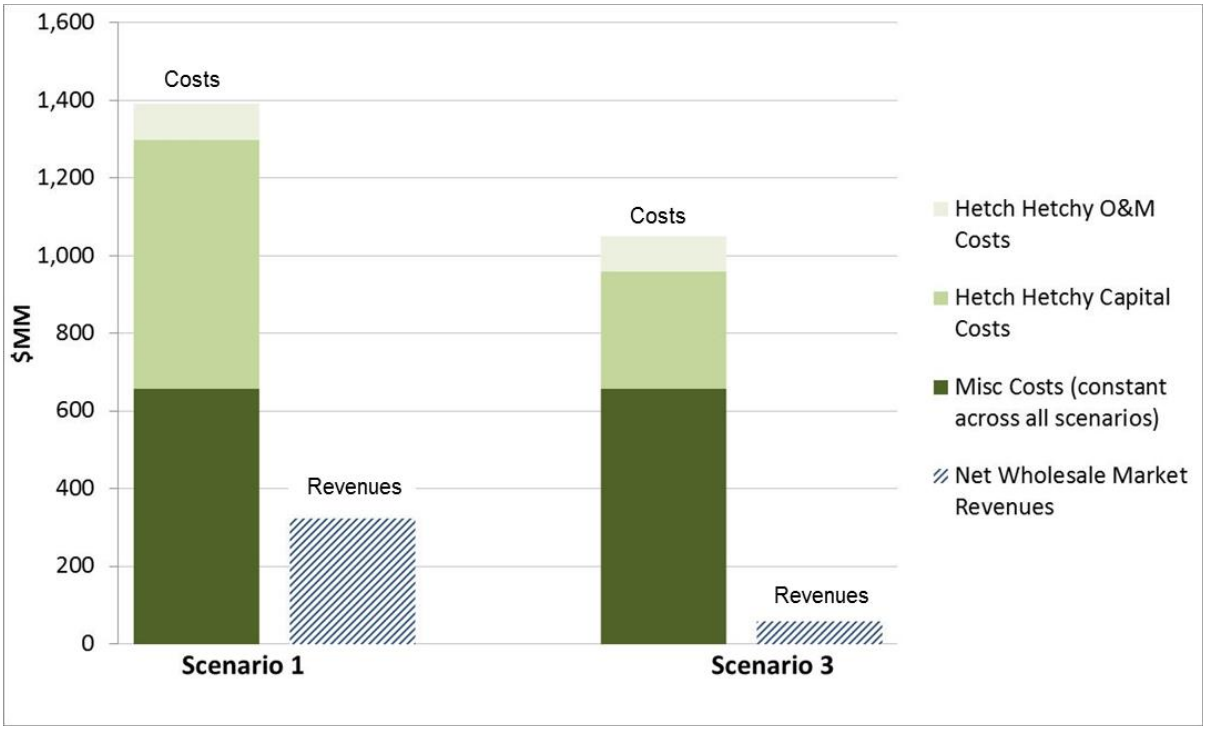

Figure 1-4 NPV Results, Scenario 1 versus Scenario 3

Figure 1-5 shows a graphical representation of the NPV for Scenarios 1 and 3 over the analysis period for select economic scorecard items, along with the difference in cumulative NPV. To more clearly show the difference in NPV between the scenarios, only the items that differed between the cases (capital costs, operations and maintenance [O&M] costs, and market sales/purchases) were included in this figure. The "Other Costs" shown above are excluded.

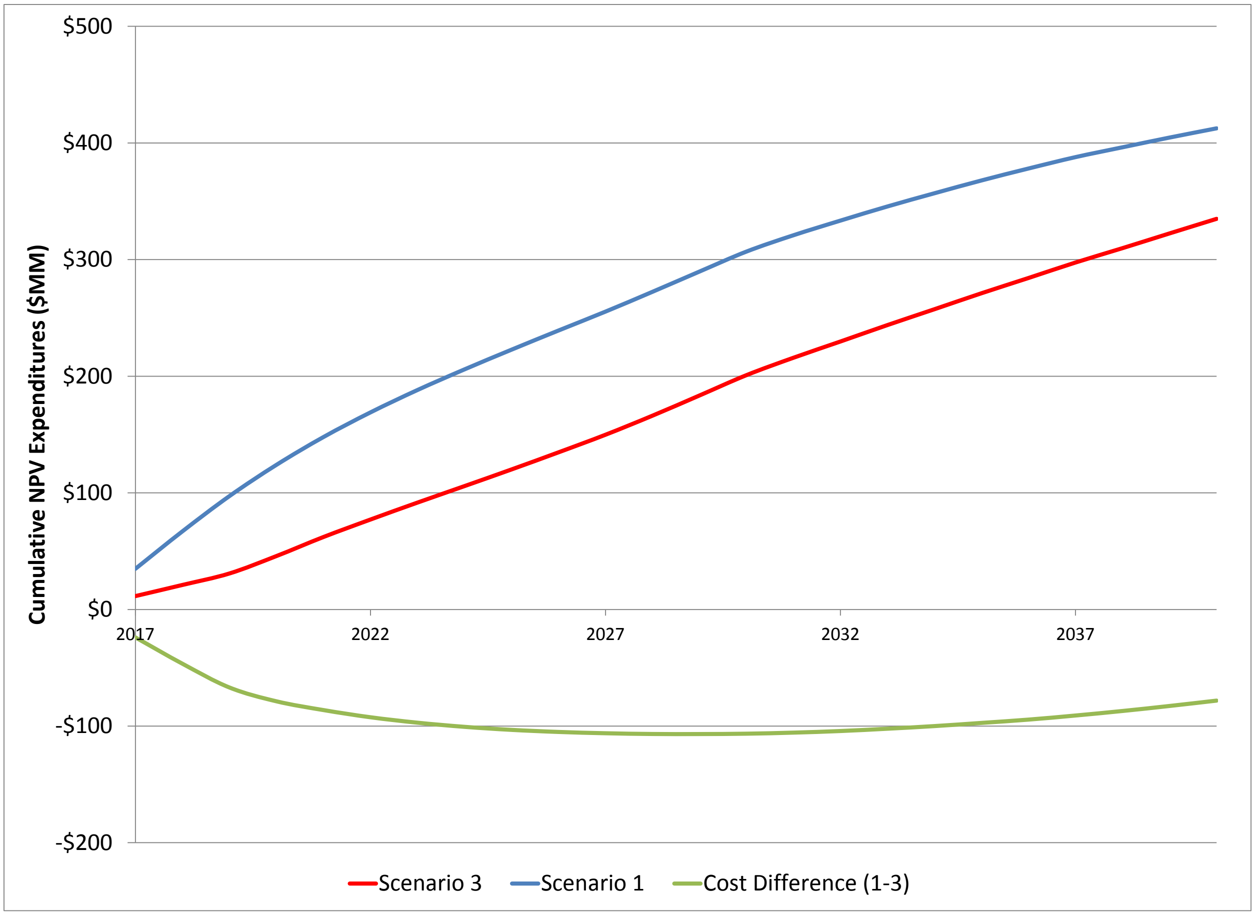

Figure 1-5 NPV Comparison of Select Inputs, Scenario 1 versus Scenario 3

As Figure 1-5 shows, the savings to SFPUC in Scenario 3 relative to Scenario 1 quickly reaches $100 million after about 5 years due to deferral of the capital investments in the MPH. It should be noted that because of the way capital costs are modeled in this analysis (the equivalent annual annuity [EAA] method, which spreads out and normalizes capital expenditures), this analysis does not indicate as to when the actual costs will be incurred by the SFPUC. For Scenario 1, this approach does not reflect the high cost of near term expenditures (from costs incurred for Mountain Tunnel work), resulting in Scenario 1 being even more expensive in the early years of the analysis. ***As such, the EAA method and the IRP process are meant to identify differences between cases over a long planning period and are not intended to replace the biannual budget and investment cycle.***

A number of assumptions were made as part of the IRP modeling to forecast the economic value of each scenario. To test the impact of changes in these assumptions, key sensitivity areas were identified in consultation with SFPUC staff. The sensitivities found to have the most variation and greatest potential impact were changes in load growth and market power prices. Given the current load growth projections, renewable energy capacity additions showed little benefit to the SFPUC system. The majority of the benefit of adding renewables identified through the model is from the concurrent addition of hourly dispatch optimization (roughly $40 million on an NPV basis, excluding the additional operating costs that would be required).

To provide a comparison of the resource options available to SFPUC if a large amount of load growth were to occur, Scenarios 1 and 3 under High Load were compared, as well as Scenario 3 with the addition of 50 megawatts (MW) of wind via a power purchase agreement (PPA). The amount of net market purchases or sales and NPV of each of the three sensitivity cases is shown in **Table 1-4**. The NPVs are much higher (more costly) than the base case scenarios because of increased market purchases, greater resource adequacy (RA) needs, and higher California Independent System Operator (CAISO) transmission and distribution (T&D) charges.

Table 1-4 Net Sales and NPV, High Load Sensitivity Cases

	SCENARIO 1 HIGH LOAD	SCENARIO 3 HIGH LOAD	SCENARIO 3 HIGH LOAD WITH WIND
Net Sales (GWh)	+2,119	-7,363	-4,501
NPV ($million)	1,587	1,618	1,490 (lowest)

When only Scenarios 1 and 3 are compared without additional resources, Scenario 1 becomes slightly more economically attractive. However, if SFPUC were to face a significant net short position, a range of generation options should be considered so that exposure to market power prices could be reduced. Adding 50 MW of wind power to Scenario 3 significantly reduces the net short position and is more economically attractive than Scenario 1. It should be noted that 50 MW was added to be consistent with the renewable energy sensitivity case, but this figure should not be considered an optimal amount of new resource additions if the future SFPUC load was in fact projected to be higher than the base case; optimizing generation options for cost-effectiveness may yield an even lower NPV result. As a better understanding of load growth is developed in the future, additional generation options should be considered if confidence grows that SFPUC generation will become significantly short in meeting load.

To test the impacts of different market power prices, a new set of hourly prices for the entire analysis period was entered into the PLEXOS model for Scenarios 1 and 3. Both high power and low power price cases were analyzed, reflecting the range of potential costs projected by Black & Veatch. A depiction of the market price range explored throughout the analysis period relative to the generation cost for the three powerhouses can be seen on **Figure 1-6**. *Note that the cost of generation for each powerhouse does not include overhead.*

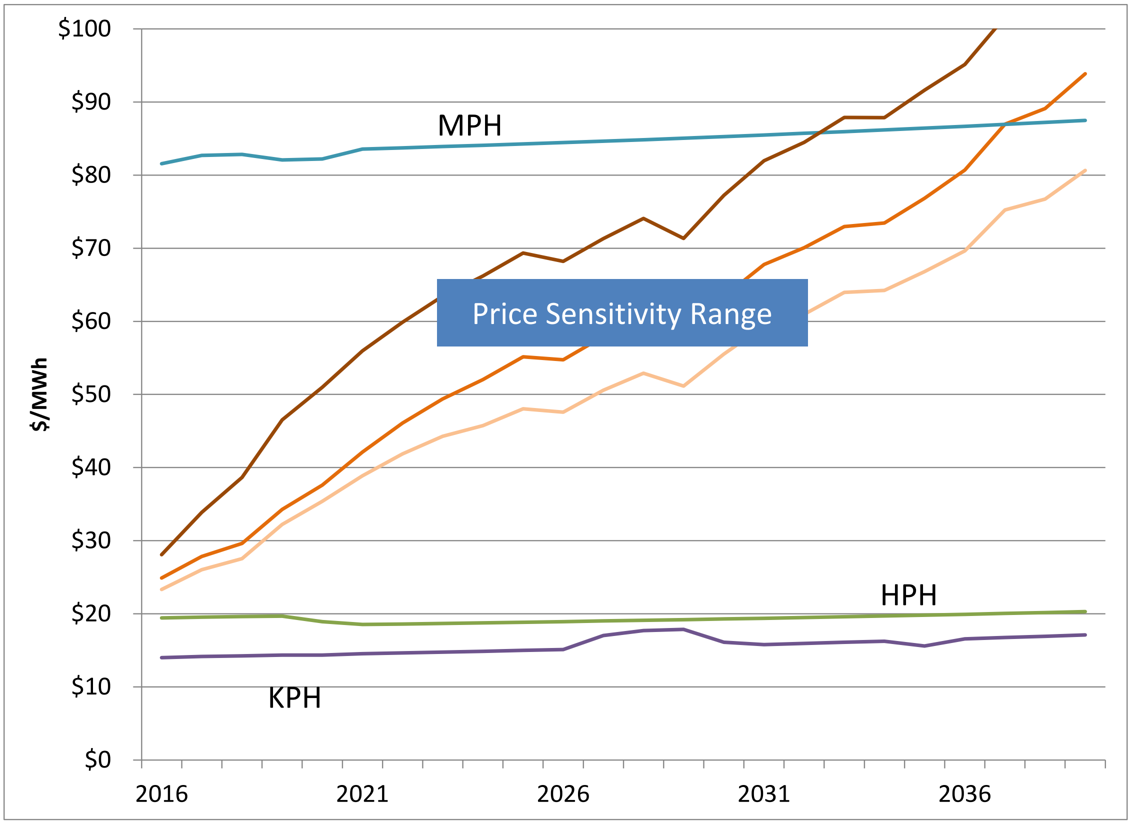

Figure 1-6 **Market Price Sensitivity Range versus Hetch Hetchy Generation Costs Without Overhead**

The NPV for Scenarios 1 and 3 under each of the three market power price cases can be seen in **Table 1-5**.

Table 1-5 **NPV of Scenario 1 and 3 Power Price Sensitivities**

NPV ($MM)	SCENARIO 1	SCENARIO 3	LOWEST COST
High Power Price	990	973	Scenario 3 ($23MM)
Base Case	1,068	990	Scenario 3 ($78MM)
Low Power Price	1,103	993	Scenario 3 ($110MM)

From the results of this analysis, a couple of key conclusions can be drawn:

- ***Scenario 1 Remains Uneconomical Even With High Power Prices:*** *While the difference in NPV shrinks between Scenarios 1 and 3 in the high power assumption, Scenario 3 remains more economically attractive.*
- ***Potential for Low Power Pricing Provides Further Support for Scenario 3:*** *The NPV gap widens if market power prices are lower than projected in the base case. Regardless of the market power price explored, Scenario 3 remains more economically attractive.*

Besides the economic analysis outlined above, there are a number of qualitative factors that should be considered when evaluating the different resource options available. These largely represent risks due to changes in assumptions or market conditions, utility preferences, and the ability to respond to unforeseen operational situations.

Table 1-6 shows the major qualitative factors evaluated as part of the IRP, and how Scenarios 1 and 3 compare under each. Each scenario is scored on a metric of green (little to no concern), yellow (caution is advised), or red (high risk or concern of unfavorable outcomes). Factors are listed in the order of greatest to least risk relative to Scenario 1.

Table 1-6 Scenario 1 and 3 Qualitative Factor Rankings

FACTOR	DESCRIPTION	SCENARIO 1	SCENARIO 3
Capital Investment Risk	Risk of long-term uneconomical or stranded assets	High risk of carrying forward significant long-term debt on uneconomical MPH asset	Flexibility to invest in only the most economic assets while adapting to market conditions
Market Exposure Risk	Financial uncertainty due to high level of variability in market prices	Considerable exposure to market prices due to oversupply; uneconomical regardless of forecasted changes	Balanced supply and demand; minimal exposure
Supply Diversity	Diversity in generation resources	Remains heavily invested in hydro generation	Flexibility to choose greater diversity to meet future load obligations economically
Technology Leadership/ RPS Content	Deployment and support of advanced generation technologies for power generation	Large hydro generation only	Greater consideration of new renewable resources to meet load
Load and Operational Flexibility	Ability to adapt to major changes in system load or performance requirements	Limited flexibility because of high level of generation commitments exceeding load and water first requirements	Flexible as needs change; could purchase new assets if needed or economically sell excess

FACTOR	DESCRIPTION	SCENARIO 1	SCENARIO 3
Impact of Variable Weather Conditions	Performance under different weather conditions	Greater financial losses during wet years because of more MPH sales	Higher market exposure during dry years, but impact is limited
Environmental Performance	Level of criteria pollutants and greenhouse gas (GHG) emissions	No fossil assets and few market purchases	No fossil assets; flexibility to choose future generation sources
Service Redundancy	Ability to meet service performance obligations	Excess generation capacity available to meet needs if system issues arise	Balanced supply and demand; would be more dependent on market in case of generation issues
Ownership/ Independence	Dependence on third parties to meet load obligations	No new third-party obligations	Potential third-party obligations if future load rises; could also meet through SFPUC ownership
Intrinsic Value to CCSF	Maintaining assets of historical importance	Preservation of Hetch Hetchy legacy assets	Deferral of investment in a historically significant asset (Moccasin)

The items of greatest difference between Scenarios 1 and 3 (and most negative for Scenario 1) are capital investment risk and market exposure risk. The economic value to Power Enterprise of MPH under a range of future scenarios is likely to be low in relation to other options for meeting load. Scenario 1 also has less potential supply diversity and technology leadership (there is no projected need for new resources even under a high load demand in Scenario 1, while non-hydro resources are projected to be the preferred option to meet high load demands under Scenario 3) and less flexibility to respond to changes in load or operational needs. Three factors were more favorable for Scenario 1 than for Scenario 3: service redundancy, ownership, and intrinsic value. Scenario 1's large excess of generation provides a cushion to reliably meet system loads in case of operational problems at any of the powerhouses. In addition, SFPUC maintains ownership over all generation assets in Scenario 1, while Scenario 3 may rely on third-party generation to meet future load obligations economically. Finally, deferring investment into Moccasin Powerhouse in Scenario 3 would impact the operation of an historical asset that has been in operation since 1925.

1.3 CONCLUSIONS

This IRP examines several options for future resource needs and system uncertainties within the power supply portfolio, including deferral of MPH investments, addition of renewable resources, changes in load, and impacts in market pricing. The base case analysis shows that pursuing a balanced supply and demand portfolio and deferring investment in MPH provides an NPV advantage of nearly $80 million over the 25 year analysis period, along with lowering capital investment and market exposure risks. This option also provides flexibility to meet future load changes at lower cost, either through new resource addition, or selling future excess into the market economically in the event of lower than expected load growth.

Additional key findings from the analysis include the following:

- *Balancing load and generation insulates SFPUC from any volatility in market power pricing. This was shown when the Scenario 3 NPV varied little regardless of the market power price assumed.*
- *Load growth and significantly higher market prices would need to be more certain and sustained to justify additional SFPUC generation beyond what is needed for load.*
- *HPH and KPH are roughly breakeven with market price once overhead costs are added in the initial years of the analysis, becoming economic in all cases relative to the overall energy market as market prices increase.*

Finally, it is understood that Power Enterprise decisions must take into account the overall goals and constraints of the broader SFPUC organization. This IRP utilizes an approach and best practices consistent with those at other electric utilities but does not include the impact of any of the scenarios on Water operations, qualitative factors related to any non-Power Enterprise issues, or the overall economics of SFPUC as a whole. A broader organizational approach should use the results of this IRP document as inputs to that type of decision-making.

2.0 Background

The SFPUC, a department of the City and County of San Francisco (CCSF), provides water and wastewater services to San Francisco, along with power to San Francisco's municipal departments and select commercial and residential customers within the CCSF. The majority of the power generated by the SFPUC comes from three hydroelectric facilities located in the Sierra Nevada Mountains. These three facilities are operated to meet SFPUC's water needs first, with power then generated from the system used to meet customer demand. The market purchases or sales of power are based largely on the hydroelectric generation profile throughout the year.

The SFPUC is unique among most utilities in California in that it possesses significantly more generation than it has demand. Currently, it has roughly 380 megawatts (MW) of generation capacity for a system with a peak load of roughly 150 MW. As shown in **Figure 2-1**, this leads to a greater net long position relative to other California municipal utilities; most of the excess generation is sold on the open market during the spring hydro runoff period.

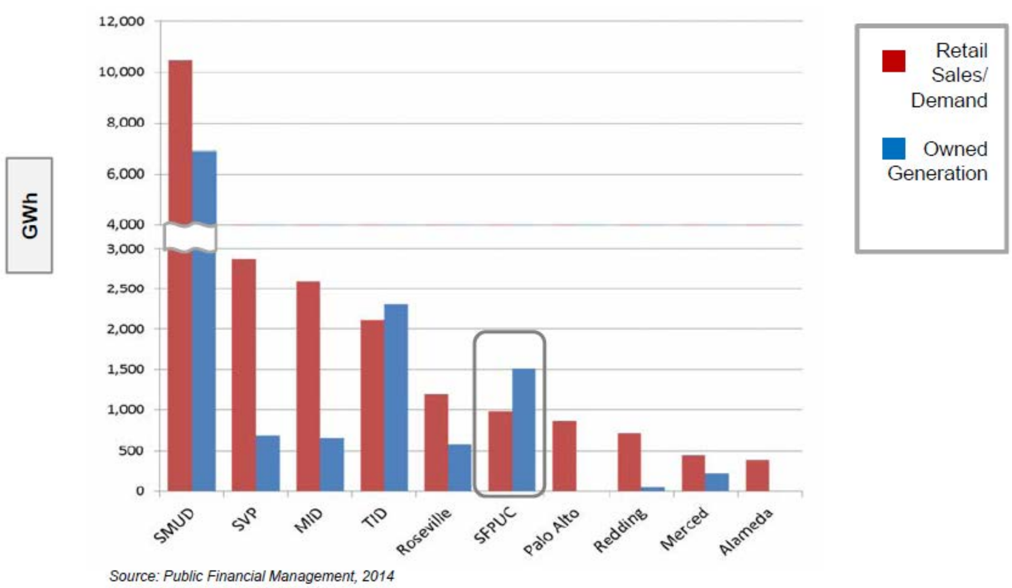

Figure 2-1 Demand and Generation Balance, Select California Publicly-Owned Utilities

Changes in market supply and demand for wholesale power have greatly affected the SFPUC. Low natural gas prices coupled with an abundance of low-cost renewable energy resources have suppressed wholesale power prices, lowering the revenue to SFPUC from its market sales. Moreover, the hydro assets are facing considerable investment needs if they are to continue to operate as they have in the past, further placing pressure on overall system revenue. Finally, a number of state and local regulations affecting electric utilities have been introduced in the past years with which SFPUC must comply.

The overall goal of SFPUC's resource plan is to maintain highly reliable electric service for its customers at affordable costs, while taking into consideration environmental impacts and system risks to ensure that near-term decisions made are robust. Just as importantly, SFPUC wants to retain flexibility in its resource portfolio so that the utility is well positioned to respond to future regulations and technologies. In developing this Integrated Resource Plan (IRP), SFPUC has undergone an analytical process to evaluate available resource alternatives and to establish a resource procurement plan that satisfies SFPUC's resource planning goals.

This IRP examines options for operations of its three hydroelectric facilities (Kirkwood Powerhouse [KPH], Holm Powerhouse [HPH], and Moccasin Powerhouse [MPH]) under a variety of scenarios. The following three main scenarios were evaluated:

- ***Scenario 1 – Maintain Current Generation****: All necessary investment to maintain current level of generation through 2041.*
- ***Scenario 2 – Delay Some Projects****: Operation reflecting approved Capital Investment Plan (CIP) projects only for Years 1 through 10, with unfunded needs delayed until Years 11 to 25 of the analysis.*
- ***Scenario 3 – Defer Moccasin****: Defer MPH and water conveyance projects throughout the study period.*

In addition to the three main cases, sensitivity analyses were performed to determine the impact of the following modifications:

- *Addition of renewable resources*
- *Meteorlogical uncertainty*
- *Market price uncertainty*
- *Increased load growth*

The overall net present value (NPV) was calculated for each scenario to define the impact of each option. This calculation was coupled with qualitative factors to help inform the choices being made for future operation of the SFPUC Power Enterprise.

The remainder of this report is organized into the following sections:

- ***Section 3: IRP Process and SFPUC Operations****. Introduces the approach taken in the SFPUC IRP. Provides background on the current state of SFPUC generation, transmission, and load.*
- ***Section 4: IRP Modeling Assumptions****. Outlines the process for gathering the necessary information for input into the IRP models and the final basis for key entries.*
- ***Section 5: IRP Modeling Methodology****. Details the scenarios modeled as part of the analysis, the analytical tools used, and the analysis basis for scenario comparison.*
- ***Section 6: Portfolio Results****. Provides the results of the analysis and a discussion of the significance.*

3.0 IRP Process and SFPUC Operations

3.1 INTRODUCTION

Integrated resource planning is the process that utilities undertake to determine generation resources required to meet future peak and energy demand on its system, while ensuring an adequate reserve margin is maintained for system reliability and integrity. This is accomplished by analyzing a combination of supply and demand considerations over a specified study period.

Through the evaluation of various supply and demand-side alternatives, the IRP process can be used to develop guidelines for procurement decisions in a manner that satisfies core principles of system reliability, fiscal responsibility, and environmental stewardship, and provides a reasonable degree of flexibility to respond to future economic, regulatory and technological changes. The best resource plans create a reasonable balance between fiscal responsibility and environmental stewardship, and present reasonable risks and associated costs to customers. All plans selected must maintain generation reliability at or above industry-standard levels.

IRPs are developed and evaluated primarily on the basis of economic performance; they utilize economic analyses and methodologies to assess various scenarios and sensitivities to arrive at an *economically* optimal plan. The optimal economic plan may or may not reflect the same conclusions that a pure financial analysis might conclude; one considers the most economically beneficial plan irrespective of a utility's financial condition. Financial factors such as borrowing costs, capital structure, timing of cash flows and earnings, are excluded from this economic evaluation process. Incorporation of financial metrics into the economic results may result in modifications to the structure, timing, and design of the preferred or recommended plan.

IRPs provide many benefits to consumers as well as positive impacts on the environment. This is a planning process that produces results that, if correctly implemented, provides the lowest costs at which a utility can deliver reliable energy services to its customers. IRPs differ from traditional resource planning in that they require the use of sophisticated analytical tools that are capable of fairly evaluating and comparing the costs and benefits of supply and demand resources as well as the integration of utility-scale and distributed energy resources.

Alternatives examined by IRP efforts may include assessing generating capacity additions, implementing energy efficiency (EE) and demand response programs, and determining the system transmission and distribution impacts and requirements for plan implementation. Uncertainties assessed through scenario or sensitivity analyses in IRPs include market prices, load growth, variability of renewables, market structure, and regulation impacts.

Figure 3-1 illustrates the resource planning process; a more detailed methodology with inputs specific to SFPUC is in Section 4.0.

STEP 1 — **ASSESS NEEDS**
Develop forecasts of load growth, plant conditions, contract terms, and operational constraints to determine resource needs over the planning horizon.

STEP 2 — **CONSIDER RESOURCE SOLUTIONS**
Evaluate available generation resources, including renewable and long-term market power purchases, to identify the role each will play in meeting customer needs.

STEP 3 — **EXAMINE PLANNING FRAMEWORK AND RISKS**
Identify and assess challenges inherent in the current business and regulatory environment. Develop a multi-faceted risk management approach that considers how plan drivers may change during the planning period.

STEP 4 — **DEVELOP RESOURCE PORTFOLIOS**
Develop resource portfolios through a screening process, followed by a detailed quantitative and qualitative evaluation process to develop preferred portfolios. The evaluation relies upon the needs assessment and planning data specified in previous steps.

STEP 5 — **PERFORM SCENARIO AND RISK ANALYSIS**
Further evaluate preferred resource portfolios through scenario and risk analysis to assess performance under a range of potential market and industry conditions.

STEP 6 — **PRESENT RESULTS**
The goal and intent is that any identified resource portfolio(s) will reliably and sustainably serve demand, utilize renewable and energy efficient resources, and account for inherent risks at a reasonable long-term cost and be flexible enough to respond to any business, policy, or regulatory changes.

Figure 3-1 Integrated Resource Planning Process

Following the process outlined on Figure 3-1, several high level questions need to be addressed as a critical examination of the IRP:

- *What resources does SFPUC need?*
- *What are the timing and operational characteristics of those resource needs?*
- *What kind of resources are best to meet those needs?*

Scenarios that provide the most overall value to SFPUC customers over the planning period, while maintaining system reliability, balancing fiscal responsibility, and meeting environmental sustainability goals are those that should be pursued by the SFPUC. While there are a number of commodity price and regulatory risks over the planning horizon, the best scenarios meet a "no regrets" test that would be suitable for the near term regardless of changes that occur throughout the evaluation period.

3.2 SFPUC POWER ENTERPRISE GENERATION AND OPERATIONS

The Hetch Hetchy Water and Power System is the clean energy backbone of the CCSF. The diverse energy portfolio has a zero GHG emissions profile, it does not produce any harmful radioactive byproducts, or leave behind any waste. By relying on clean, GHG-free Hetch Hetchy energy, San Francisco avoids discharging approximately 175,000 metric tons of carbon dioxide (CO_2) each year into the atmosphere. The Hetch Hetchy Power System supplies clean energy to all of San Francisco's municipal buildings, services, and customers, which include San Francisco International Airport (SFO), San Francisco General Hospital, Municipal Transportation Agency (MUNI), police, fire, city tenants, and more. The Power Enterprise's full-service customers include the waterfront and mid-market locations (50 MW), airport (50 MW), and other San Francisco loads (50 MW).

Power is one of three enterprises of SFPUC, with sales of 1.6 million MWh of electricity annually. SFPUC is the exclusive provider of electricity to residential and business customers in the Hunters Point Shipyard (Redevelopment Phase I) and on Treasure Island. A number of clean energy initiatives have been implemented by SFPUC, including renewable and energy efficiency projects, GoSolarSF, and electric vehicle charging stations.

The nature of SFPUC's generation and operations poses the following challenges:

- *The Hetch Hetchy system operates under a "water first" policy that prioritizes water needs over power generation, limiting SFPUC's ability to take advantage of buying and selling power on the open market.*
- *Water settlement agreement limits investment discretion for power*
- *Hetch Hetchy assets are now over 50 years old*
- *Reinvestment is required to maintain a reliable system capacity of 380 MW*
- *Revenue from the wholesale market is volatile and depends on whether it is a wet or dry year*

3.2.1 Hydroelectric System

The Hetch Hetchy Power System is composed of three hydroelectric powerhouses (**Table 3-1**):

- *Moccasin Powerhouse and a nearby small in-line hydroelectric unit rely on gravity-driven water flowing downhill from the Hetch Hetchy Reservoir*
- *Kirkwood Powerhouse, like Moccasin, is also dependent on gravity-driven water flowing downhill from the Hetch Hetchy Reservoir*
- *Holm Powerhouse relies on gravity-driven water flowing downhill from Cherry Lake*

Figure 3-2 provides an illustration of the Hetch Hetchy Power System area.

Table 3-1 SFPUC Existing Hydro Generation

HETCH HETCHY LARGE HYDRO		
380 MW (96% of Total)		
Powerhouse	**Capacity**	**Units**
HPH	165 MW	2
KPH	116 MW	3
MPH	100 MW	2

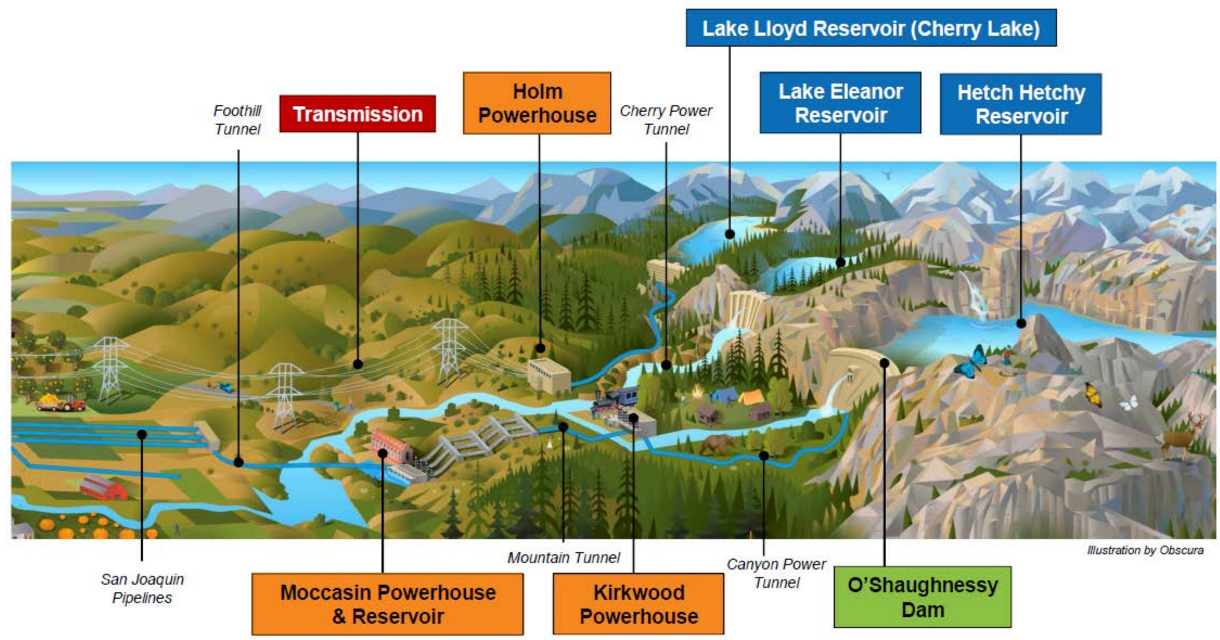

Figure 3-2 Hetch Hetchy Power System Area
(Source: SFPUC)

Each powerhouse transmits its energy to the Bay Area along city-owned transmission lines that traverse the state of California. Power is wheeled into San Francisco from the Newark Substation via PG&E-owned lines; more information on transmission can be seen in Section 4.4.

3.2.2 Solar Energy and Other Generation Sources

SFPUC municipal solar arrays have a generating capacity of 8 MW of clean, renewable solar energy. Some of the larger arrays include the following:

- *The Sunset Reservoir Solar Project (5 MW). The Sunset Reservoir Solar Array is San Francisco's largest solar installation under a 25 year Power Purchase Agreement (PPA). The Sunset Reservoir Project more than tripled San Francisco's supply of renewable energy. The project* *supports public buses, the San Francisco International Airport, health clinics, and other vital city services.*

- *Moscone Center Solar Array (676 kilowatts [kW])*
- *San Francisco Airport (456 kW)*

Two biogas generation facilities have a generating capacity of three megawatts of clean, renewable energy from the wastewater decomposition process. The facilities are located at the Southeast Wastewater Treatment Plant and the Oceanside Wastewater Treatment Plant.

3.2.3 Distributed Energy Resource Projects

SFPUC applies an annual budget of roughly $3.5 million towards distributed energy resource (DER) projects at locations throughout the City of San Francisco. These DER projects include implementation of energy efficiency and building controls upgrades at municipal facilities, building commissioning and retro-commissioning services, rooftop solar systems, energy storage systems, and other projects that impact daily energy usage patterns.

Notable recent and ongoing DER projects include the following:

- Civic Center Sustainability District HVAC and Lighting Retrofits
- Commissioning at San Francisco International Airport
- Rec & Park Garage Automatic CO Sensor Controls Upgrades
- Fine Arts Museums (de Young Museum, Legion of Honor) LED Lighting Retrofits
- Thurgood Marshall Rooftop Solar Array with Energy Storage

Together, energy efficiency projects completed by SFPUC, since the inception of the DER program, are saving over 50,000 MWh of electricity use and 2 million therms of gas use each year, while adding 3.2MW of rooftop solar throughout the City. Furthermore, the DER program continues to explore opportunities for installing battery storage, promoting electric vehicle charging, fuel-switching from fossil fuel-based water and space heating, and leveraging new technologies for demand-side load management.

4.0 IRP Modeling Assumptions

The intent of the IRP is to evaluate power supply options to meet future load and policy requirements. IRPs assess market changes, costs, risks, and options for managing the power supply. Developing assumptions for modeling the SFPUC system, including the capital investment plans, power supply options, load growth, market options, and ability to keep environmental impacts minimal, was the first step in the IRP process. SFPUC and Black & Veatch worked closely on developing the parameters that form the basis for the analytical framework that drives the IRP process.

4.1 APPROACH TO DATA COLLECTION

SFPUC formed six Working Groups (**Table 4-1**) focused on developing IRP assumptions. ***These WGs were carefully formed so that all base assumption for modeling the SFPUC system would be collaboratively compiled and fully reviewed by the SFPUC experts and representatives from Power, Water, Finance, and Regulatory Affairs groups.*** Please refer to Appendix A for a list of WG members and meetings that took place during the study.

The basis for the system analysis is the PLEXOS production cost model, as described in more detail in Section 5.0. Each working group was focused on a group of inputs needed to appropriately model the SFPUC system. Working Groups and Black & Veatch worked closely to review the assumptions and collaborate on the best use of data for modeling purposes. This effort also developed a set of portfolios and sensitivities to be modeled using PLEXOS.

Table 4-1 Working Group Focus and Deliverables

WORKING GROUPS	KEY FOCUS
1 - Cost Allocation	Capital, Operating and Programmatic Budgets Assigned to Each of the Powerhouses
2 - Generation and Power Contracts	Hydro System Performance Characteristics
3 - Transmission	Transmission System Characteristics And Market Relationship Definitions
4 - Market Prices	Energy Market Assumptions
5 - Electric Demand	Demand Forecast Characteristics
6 - Regulatory and Policy Requirements	Energy and Water Policy Characteristics Impacting Future Procurement Decisions and Hydro Operations

Each working group's role and deliverables is discussed in Sections 4.2 through 4.7. **Figure 4-1** is an overview of the main set of assumptions developed by each working group and the general approach in using the assumption in the models developed by Black & Veatch.

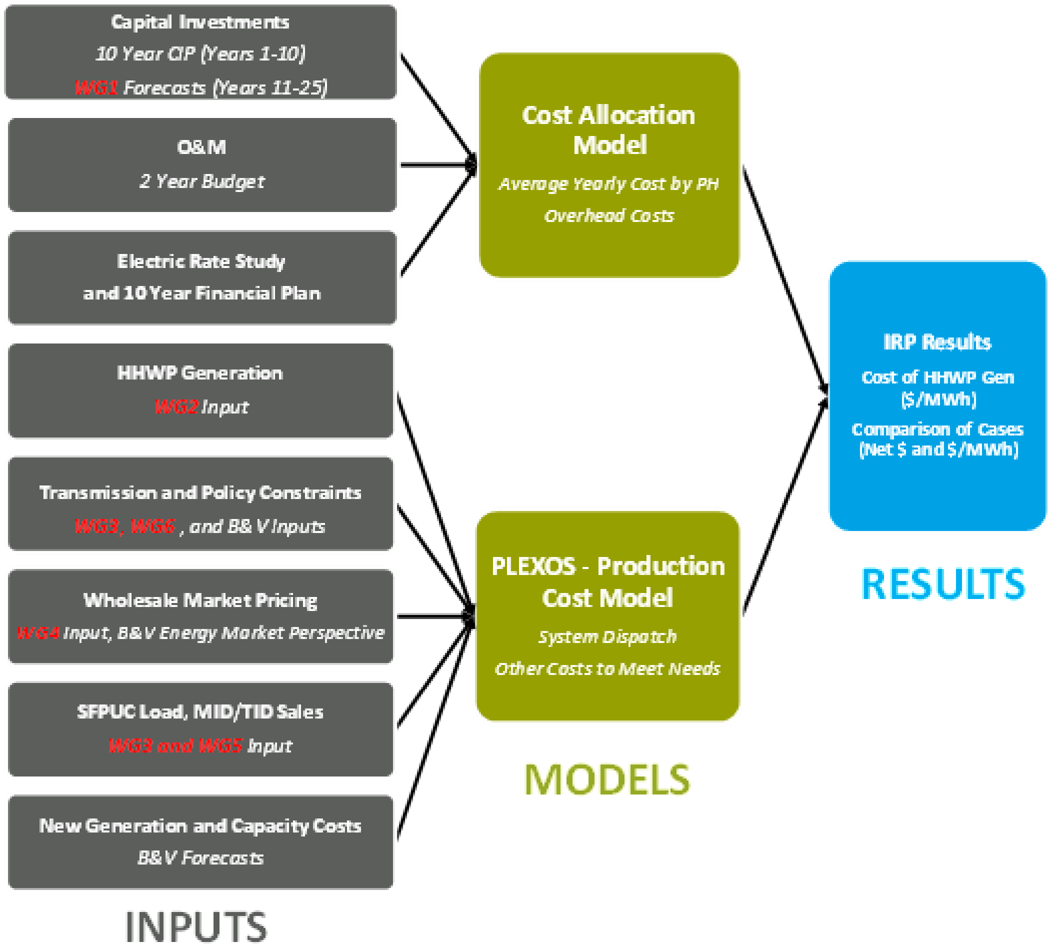

Figure 4-1 Approach to Data Collection and Usage

4.2 WORKING GROUP 1 - COST ALLOCATION

The typical IRP focuses on total variable, fixed, and capital costs for the entire system and not on allocation to a specific set of resources within the portfolio. The primary metric for determining the desirability of a specific portfolio recommendation is the present value revenue requirement (PVRR), sometimes used interchangeably with the NPV of total system costs. ***These values are important because they represent the revenue that the utility must collect in the future (on a present value basis) to reliably serve its customers, while meeting regulatory compliance goals such as RPS and GHG emissions goals.***

For SFPUC's IRP, Working Group 1 responsibilities included capturing all known costs for inclusion in the analysis, developing the cost allocation methodology and principles, defining an approach for comparing assets with different functional lives, and generating inputs to the PLEXOS model.

4.2.1 Data Used

The development of the Cost Allocation Model (CAM) requires data inputs from not only the other Working Groups, but also a significant amount of data from Finance and other SFPUC departments. **Table 4-2** summarizes the data sources used in the CAM.

Table 4-2 Data Sources

DATA NEED	SOURCE
Operating Budgets	Adopted operating budget provided by Hetch Hetchy Water and Power (FY15-16).
Capital Improvement Program	Approved 10 Year capital improvement program (FY15-16).
Future Year Projections - Operational	HHWP 10 Year Financial Plan provided by Finance. SFPUC Electricity Revenue Requirements (part of the 2016 Rate Study) provided by Finance.
Future Year Projections – Capital	Scenarios 1 through 3, with Years 11 through 25 projects and allocations provided by HHWP.
Future Year Projections – Hydro Data	Scenarios 1 through 3 Hydro Generation assumptions.
Debt Service Schedules	Schedules confirmed by Finance.
Purchased Power Projections	Provided by Power Resources, including detail for renewables, such as the Sunset PPA, solar, and energy efficiency needs.
Head Count	Confirmed in 10 Year Financial Plan for Hetchy Power by Power Admin and for HHWP by HHWP Admin
Financial Policies	Provided by Finance

4.2.2 Cost Allocation Approach

The cost allocation process used in the IRP is consistent with that used by SFPUC in its 2016 rate study. The difference between the work performed in the 2016 rate study and the IRP is that, because of SFPUC's desire to examine the impact of powerhouse investments, allocations are more granular in the CAM.

Whether a utility is conducting a rate study or an indirect cost study or performing an IRP, the process of allocating costs follows the same three basic steps (shown on **Figure 4-2**): functionalize the cost, allocate the cost, and distribute the cost. Details can be found in Appendix B.

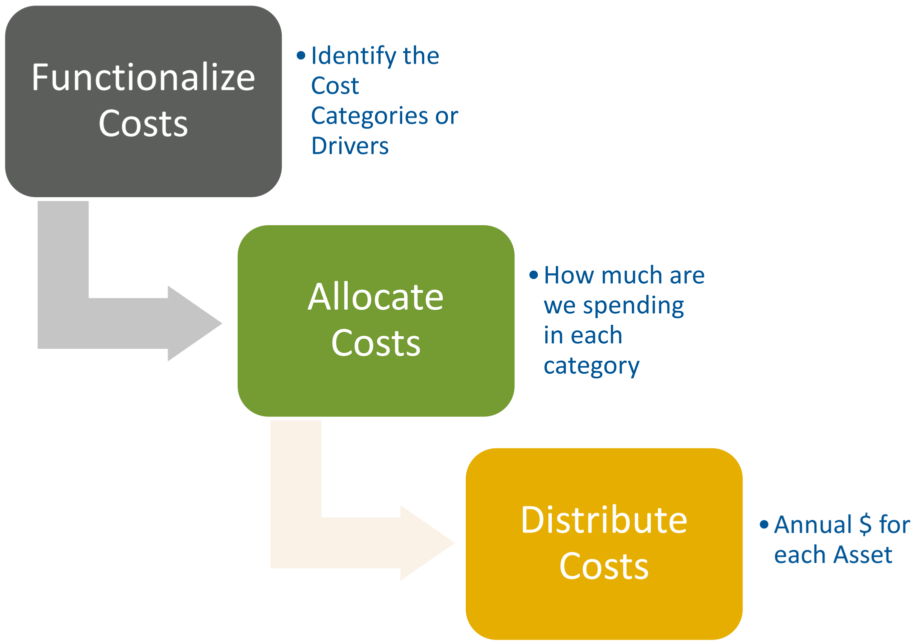

Figure 4-2 Cost Allocation Process

4.2.3 Equivalent Annual Annuity Approach

Of particular concern to SFPUC in developing this IRP is the valuation of assets with different functional lives. Working Group 1 members considered different methods for accounting for these differences in the IRP.

Resource planners understand that existing and new resources may have different useful lives, book values, and terminal values. These concepts are defined as follows:

- *Useful life is the estimated lifespan of a depreciable fixed asset, during which it can be expected to contribute to operations. This is an important concept in accounting, since a fixed asset is depreciated over its useful life.*
- *Book value is the value of an asset according to its balance sheet account balance. For assets, the value is based on the original cost of the asset less any depreciation, amortization, capital expenditures, or impairment costs made against the asset.*
- *Terminal value (continuing value or horizon value) of an asset is the present value at a future point in time of all future cash flows.*

Currently, states that require IRPs primarily focus on adding resources to meet the growing demand for electricity. There are few mandates from state regulatory agencies to address "end effects" issues for assets with differing lives. Given the uncertainty with the future capital cost of assets during the end effects period, it is not uncommon for IRPs to ignore terminal value when analyzing investment alternatives. While this approach can bias certain assets because of timing, the trade-off simplifies the investment decision process.

When comparing assets with unequal lives, financial metrics such as NPV and internal rate of return (IRR) can infer different conclusions as to which investment should be considered. Generally speaking, in capital budgeting there are two primary approaches to comparing the economics of projects with unequal lives:

- *The replacement-chain method seeks to align the results of NPV and IRR by analyzing the assets over a common life. This approach seeks to levelize the costs of each asset by assuming reinvestment of similar technology for the shorter-lived asset over the life cycle of the longer-lived asset.*
- *The equivalent annual annuity (EAA) method is a simpler approach than the replacement-chain method, since no assumptions regarding replacement cost are required. The process requires calculation of each project's NPV, then converts the NPV into an equivalent annual annuity payment over the project's life where the future value of the project would equal zero.*

Many utilities use the above two methods and derivations of them to address equivalent life issues for end effects assessments in IRP studies. The selection of which method depends on the objectives for each unique IRP. For example, other factors such as fuel diversity, regulatory compliance, externalities, or ancillary benefits will factor into the choice of end effects analysis.

After considerable discussion with SFPUC staff and management, the EAA approach was selected to handle this issue. The EAA provides a reasonable approach for IRP modeling purposes, and does not require a guess for when future long-term investments are required on all assets in order to match up their useful life in the replacement-chain method.

At a high level, the EAA approach uses a two-step process to compare mutually exclusive alternatives. Step one requires the calculation of NPV over the project's useful life. Then the project's EAA is calculated so that the present value of the annual annuity over the timeframe selected is equal to the project's NPV. Then each project's EAA can be compared on an equivalent basis to determine the most economical alternative, removing asset life from the influences on optimal investment.

To apply the EAA to the SFPUC assets, an assumption had to be made for the life of the annuity based on the feasible operational life of the assets. One option was to use typical debt financing terms, which are 30 years or less. However, it was determined that these terms do not take into account the true operational life of the SFPUC assets under consideration. Another would be to apply the Internal Revenue Service (IRS) Asset Class Useful Life Table for depreciation purposes; examples of IRS useful lives for assets similar to those operated by SFPUC are shown below:

- *Hydraulic Plant Equipment (canals, waterways, etc.) – 50 years.*
- *Generation and Distribution Equipment – 30 years.*
- *Other Equipment – 25 to 40 years.*

Based on a review of the assets in the CIP, it was determined that the Moccasin Powerhouse rotor is a critical operational asset. That is, without this element, there is no power generation. The operation life of this asset is 40 years. Since this is the critical asset for Moccasin Powerhouse power generation, all other assets are set to a 40 year cap. Thus, for this IRP, Black & Veatch recommended a hybrid approach that combines engineering (IRS) and financial metrics:

- *Cap the useful life for all equipment at 40 years for the EAA calculation.*
- *If an asset has a useful life less than 40 years, use the smaller number.*

Calculation of the EAA in a power context differs from water markets in the following ways:

- *All power generation assets, including hydro turbines, have book lives of 40 years or less.*
- *The payback period for fully amortized debt is 30 years or less.*[1]

4.2.4 IRP Modeling Inputs

For the SFPUC IRP, the analysis compares different energy portfolios to arrive at the least cost option. Consequently, it is important to make sure that cost comparisons are on an apples-to-apples basis. It is important to note the following about the CAM model:

- *The PLEXOS model does not consider shared overhead costs, and thus, the unit cost generated via PLEXOS does not reflect the fully burdened cost of generation because it will not include all costs that must be funded from ratepayers.*
- *The powerhouse costs, while identified separately in the CAM model, are treated as one input to PLEXOS.*
- *Only grid connection costs for the powerhouses are input to PLEXOS.*

The results of the Working Group 1 work efforts are shown in **Tables 4-3 through 4-5** for the three scenarios examined. Listed in the tables are both the cost of generation only taking into consideration powerhouse specific equipment ("Unit Cost") and the full cost of generation once Power Enterprise overhead costs are allocated to each powerhouse.

Table 4-3 Scenario 1 Investment by Powerhouse

POWERHOUSE	AVG. ANNUAL CAPITAL + O&M ($MM)	TOTAL EXPENDITURE ($MM)	GENERATION (GWH)	UNIT COST OF GENERATION ($/MWH)	COST OF GENERATION WITH OH ($/MWH)
HPH	13.4	321	16,607	19	36
KPH	8.7	208	13,357	15	37
MPH	31.7	761	8,985	84	113

[1] Although water markets tend to issue debt with terms that are 30 years or less, the use of century bonds, such as with the DC Water and Sewer Authority, is beginning to gain traction.

Table 4-4 Scenario 2 Investment by Powerhouse

POWERHOUSE	AVG. ANNUAL CAPITAL + O&M ($MM)	TOTAL EXPENDITURE ($MM)	GENERATION (GWH)	UNIT COST OF GENERATION ($/MWH)	COST OF GENERATION WITH OH ($/MWH)
HPH	13.6	325	14,891	22	40
KPH	8.7	208	13,208	15	37
MPH	32.1	771	8,937	86	115

Table 4-5 Scenario 3 Investment by Powerhouse

POWERHOUSE	AVG. ANNUAL CAPITAL + O&M ($MM)	TOTAL EXPENDITURE ($MM)	GENERATION (GWH)	UNIT COST OF GENERATION ($/MWH)	COST OF GENERATION WITH OH ($/MWH)
HPH	16.1	386	14,891	26	45
KPH	12.9	310	13,202	23	50
MPH	0	0	1,319	--	

The reason for the considerably higher expenditure for Moccasin Powerhouse is due to two large capital investment projects: Mountain Tunnel Improvement project ($616 million) and Transmission Lines 3/4 Capital Improvement Projects ($396 million). These expenditures were removed in Scenario 3. Other major projects included in the analysis regardless of the case are the improvements to Cherry ($204 million, allocated to Holm Powerhouse) and O'Shaughnessy ($107 million, split between Moccasin and Kirkwood Powerhouses) Dams. Note that the cost of generation for Holm and Kirkwood increase in Scenario 3 due to a reallocation of some expenses to these powerhouses that were previously partially incurred by Moccasin.

To provide context for how these costs of generation compare to other hydroelectric generation units, information was gathered from the US Department of Energy's Energy Information Administration. For existing plants, average total generation costs are in the $12/MWh range, assuming capital costs are sunk and no major capital improvements are necessary.[2] For new projects, estimates are $2,936 per kW for capital and $14.13 per kilowatt-year (kW-yr) for operating costs, which would equate to a levelized cost of energy of about $80/MWh at a 50 percent capacity factor without any federal tax incentives. Without applying overhead costs faced by the SFPUC, Kirkwood and Holm have costs of generation similar to existing hydroelectric plants, while Moccasin is much higher, more equivalent to the cost of generation from a new facility. This makes sense given the future capital investment expected at Moccasin due to the Mountain Tunnel and Transmission Line 3/4 Improvements.

[2] https://www.eia.gov/electricity/annual/html/epa_08_04.html.

More information on the assumptions made to develop the CAM and financial inputs into the PLEXOS model, along with a sensitivity analysis on the EAA life assumption and cost of capital applied can be seen in Appendix B.

4.3 WORKING GROUP 2 – GENERATION

4.3.1 Hydro Generation

The SFPUC hydro generation assumptions were developed by Working Group 2. The focus was on developing assumptions that best describe the current hydro system performance for the base case scenario and defining alternative scenarios for modeling purposes. The results of the Working Group 2 hydro generation assumptions differ from SFPUC's short-term 2 year budget plan because of the nature of the long term IRP analysis period; a longer set of hydrologic data is reviewed for establishment of the baseline.

Working Group 2 considered the capital investment and lifespan associated with each hydro asset in developing the scenarios. Capital investment assumptions are described in detail in Section 4.2 and the CAM results. Similarly, the lifespan of the hydro assets and the decision to utilize the EAA approach to address the end-effects issues associated with longer-lived assets for this IRP analysis are also addressed in Section 4.2. Using this method avoids the replacement cost issues inherent with the replacement-chain methodology through levelizing the cost of each asset over its expected life. These factors played a significant role in developing the portfolios described later in this section.

The base case assumed continued usage of hydro units throughout the IRP period. The year 1968 was chosen as a typical median year of hydro generation output. In a similar fashion, a typical wet and dry year were defined from a review of historical generation data as a basis for the sensitivity cases, as shown in **Table 4-6**. A breakdown of generation by asset is shown in Section 5.

Table 4-6 Representative Hydro Years Used for Modeling

REPRESENTATIVE YEARS	YEAR	TOTAL GENERATION (GWH)
Wet Year	1970	1,755
Median Year	1968	1,595
Dry Year	1994	1,485

A number of scenarios and portfolios were developed to evaluate different planning situations including the use of the current capital plan, asset deferral, and use of alternate generation. The details are discussed in Section 5.2.

4.3.2 Resource Technology Alternatives

The SFPUC must meet 100 percent of its retail sales with either qualifying Hetch Hetchy hydroelectric generation or RPS eligible resources. As part of the IRP, Black & Veatch evaluated options for the future procurement of renewable generation as an approach to meeting future demand.

The resource screening process for the IRP involved a detailed investigation of available renewable resources within California and their associated costs. In 2013, Black & Veatch completed an assessment of renewable resources for the entire state of California for the California Public Utilities Commission (CPUC), which was updated in 2016. For wind, geothermal, biomass, and biogas resources, the resource potential in each county was estimated, along with a representative hourly generation profile and an approximate levelized cost. For solar photovoltaic (PV), Black & Veatch used hourly solar generation profiles from the National Renewable Energy Laboratory (NREL) to calculate annual capacity factors and levelized costs for each 10x10 kilometer (km) grid square across the entire state, providing very granular results about resource quality. These data sets were used as the basis for selection of the alternative renewable energy resource options available to the SFPUC.

A number of different renewable portfolio options were constructed for this IRP. Statewide generic resource data were used to reflect a typical PPA proposal for providing supply to the SFPUC. Using this data, large-scale solar PV and wind projects in the Tehachapi, California, area were selected for the study with capacity factors of roughly 34 percent. In addition, a geothermal option with an 85 percent capacity factor was also included as part of the analysis. The details of incorporating the renewable generation the modeling exercise is discussed in Section 5.2.

4.3.3 Resource Adequacy

Resource adequacy (RA) plays an important role in the California market in terms of maintaining system reliability and providing compensation to generators in the form of capacity payments. The RA program is designed to meet reliability requirements by requiring CPUC jurisdictional load-serving entities (LSEs) to procure capacity 15 percent above the forecasted monthly peak load. The California RA program has multiple layers of complexity to meet reliability requirements. The 15 percent capacity requirement above forecasted system peak load is the system level requirement that is based on the 1-in-2 peak load forecast for the LSE.

Overall, SFPUC must meet a system level RA requirement of 15 percent above the forecast 1-in-2 peak, sometimes referred to as the 50/50 load forecast. Capacity can be located anywhere on the system as long as it can meet deliverability requirements to serve the monthly peak load. In general, system RA is lower cost than local RA because system RA does not need to be located in transmission constrained zones. Currently SFPUC meets system and local level RA requirements given its generation portfolio. In 2017 for example, SFPUC has system RA requirements of 166 MW and has an excess of 113MW of capacity available supplied by the Hetch Hetchy generation. CAISO projections for capacity costs were applied to reflect the cost if SFPUC needed to procure RA, which is estimated to be $26.28/kW-year from 2015 to 2019. Beyond this timeframe, it was assumed by Black & Veatch that the value of new gas capacity (currently estimated at $80/kW-year, escalated by inflation in the model) would be a proxy for capacity costs in 2020 and beyond.

4.3.4 Local Resource Adequacy

The RA program also has a local RA subrequirement that requires a certain amount of capacity be located within a transmission constrained zone. Capacity requirements in the local capacity zones are higher because planning requirements are based on a 1-in-10 peak load rather than on a 1-in-2 peak load. The local RA requirement also factors in operating contingencies such as the loss of generation or transmission line that would impact the local area.

SFPUC has local RA requirements based on the assigned CAISO proportion responsibility for its local capacity area. The local RA requirements are currently 67.93 MW, with 0.5 percent escalation added for the duration of the study to account for load growth.

4.3.5 Flexibility Resource Adequacy Capacity

To meet the 50 percent RPS requirement in California, LSEs will need to procure additional wind and solar resources by 2030. However, as LSEs add more wind and solar, they will also be responsible for procuring the associated flexible capacity based on the Flexibility Resource Adequacy Capacity (FRAC) formula[3] used by CAISO. Under the third layer of the RA program, LSEs have a Flexible Resource Adequacy Capacity Must Offer Obligation (FRAC-MOO). The SFPUC requirements were calculated as part of the CAISO FRAC-MOO requirement guidelines; in no case did the SFPUC need to procure additional reserves to meet this requirement, considering its generation portfolio and the local RA that is being purchased from PG&E.

4.4 WORKING GROUP 3 - TRANSMISSION

Electricity generated by the Hetch Hetchy Project is transmitted through SFPUC-owned and operated transmission lines, consisting of approximately 110 miles of 115 kilovolt (kV) and 50 miles of 230 kV transmission lines and four substations.

Approximately 75 percent of the Hetch Hetchy Project's generating capacity is connected to its 230 kV system via the Intake switchyard and Warnerville Substation. The remaining 25 percent of the generating capacity is normally connected to another 115 kV subsystem at the Moccasin Switchyard, which interconnects with PG&E's Newark Substation via two 115 kV lines. The transmission facilities also interconnect with PG&E's transmission and distribution systems in order to deliver SFPUC generated or purchased power to customers of the Power Enterprise in the CCSF. An overview of the SFPUC transmission topology is shown on **Figure 4-3**.

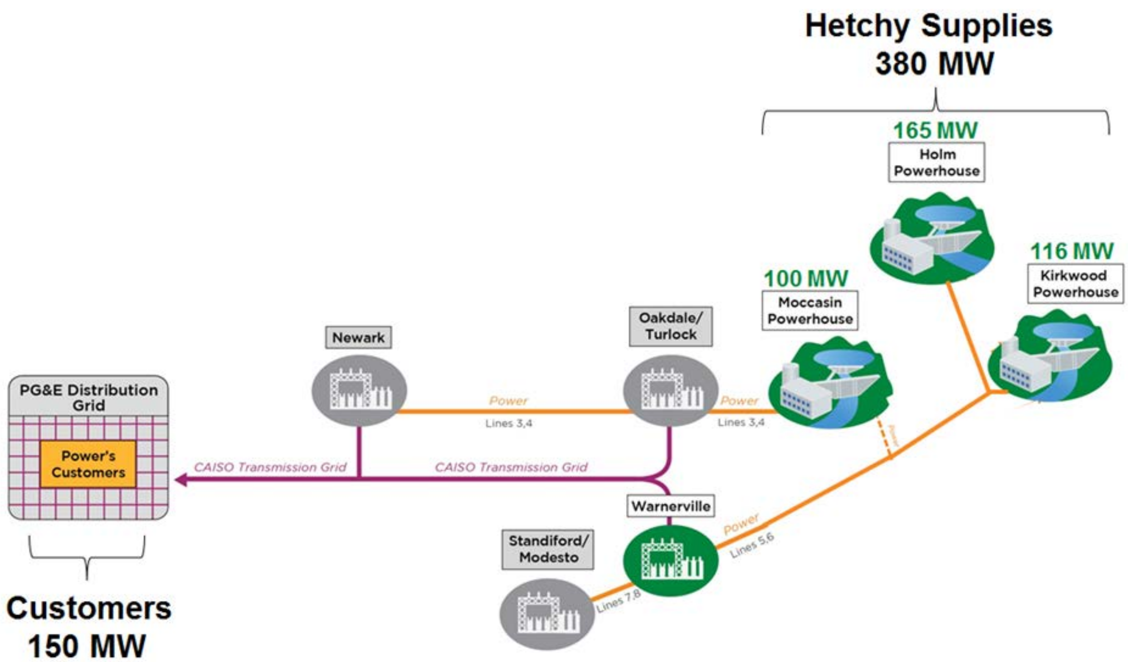

Figure 4-3 SFPUC Transmission Topology

---

[3] FRAC-MOO is calculated on a monthly basis using the maximum change in the 1 minute net load data over a 3 hour period plus 3.5 percent of the peak load for the CAISO system. LSEs are then allocated a share of the total FRAC requirement based upon their contribution from load and renewables.

SFPUC has transmission ownership rights (TOR) to SFPUC transmission lines and is currently responsible for transmission assets maintenance costs and CAISO transmission access charges (TAC) consisting of low-voltage and high-voltage TAC. Escalation of TAC has been taken into account for modeling purposes. The current TAC listed in **Table 4-7** have been escalated by 3 percent annually for the period of the study.

Table 4-7 CAISO TAC Prices

VOLTAGE	TAC CHARGES
Low Voltage	\$7.02/MWh
High Voltage	\$11.33/MWh

SFPUC's transmission topology was modeled in PLEXOS to mimic the current operation and interaction with CAISO market. This included transmission line ratings and capabilities at the interties to the CAISO market at Newark, Oakdale and Warnerville stations. The SFPUC transmission system faces minimal transmission congestion/constraints to serve the SFPUC load for the duration of this study because of the high load carrying capacity of its transmission lines. A 1 percent loss factor was assumed for all SFPUC transmission lines.

4.5 WORKING GROUP 4 - MARKET PRICING

The method typically applied in integrated resource planning incorporates a risk-based approach to determine the most optimal resource portfolio. The development and optimization of the resource portfolio starts with evaluation of several potential portfolios against Black & Veatch's fundamental market price forecast, a long-term power price forecast developed under a specific set of key assumptions. Under this approach, expected fuel market conditions influence resource options and costs evaluated in developing the IRP, and resulting forecast energy and capacity prices represent benchmark pricing and cost levels for evaluating renewable and traditional supply resources.

The Black & Veatch fundamental market price forecast (**Figure 4-4**) is developed considering the issues and perspectives facing a wide range of energy industry participants including investors, developers, lenders, utilities, and energy users. By providing a careful consideration of the multiplicity of factors impacting today's energy markets, the Black & Veatch fundamental market price forecast uses an integrated, iterative analytical process to develop a comprehensive view of the energy industry and how it can evolve in light of multiple dynamic factors.

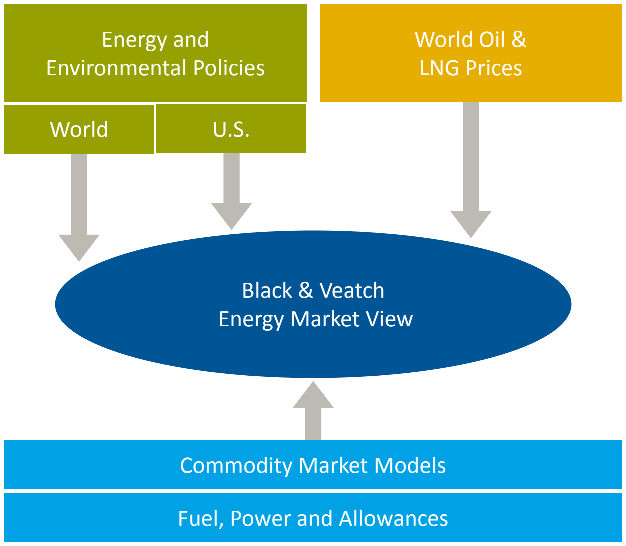

Figure 4-4 Fundamental Energy Price Forecasting

The vision of price forecasting is to provide a market benchmark that can be used by clients across a wide range of applications and is designed to capture both the broad policy level assumptions and detailed structural market representations to arrive at a consistent market forecast. From a "top down" perspective, Black & Veatch assesses the current state of energy and environmental policies at both a US and global level to determine their impact on North American and regional energy markets and prices. Black & Veatch also analyzes likely future conditions in world oil and liquefied natural gas (LNG) markets, as these markets are becoming increasingly linked to US market conditions.

Underlain by a series of fundamental structural energy market models, Black & Veatch utilizes its Integrated Market Model (**Figure 4-5**) as a basis for the current industry structure as well as a starting point for long-term analysis and price forecasting. To develop a market price forecast, Black & Veatch draws on a number of commercial data sources and supplements them with its own view on a number of key market drivers, for example, power plant capital costs, environmental and regulatory policy, natural gas finding and development costs, and gas pipeline expansions. From the fundamental modeling process, Black & Veatch has developed independent forecasts of every North American wholesale electricity market. This zonal analysis of the regional markets incorporates the results of Black & Veatch's assessment of market-based capacity additions and retirements, the impact of potential GHG legislation, and the inter-zonal transmission transfer capabilities implicit in the existing transmission system and the new transmission facilities needed to facilitate renewable resource development.

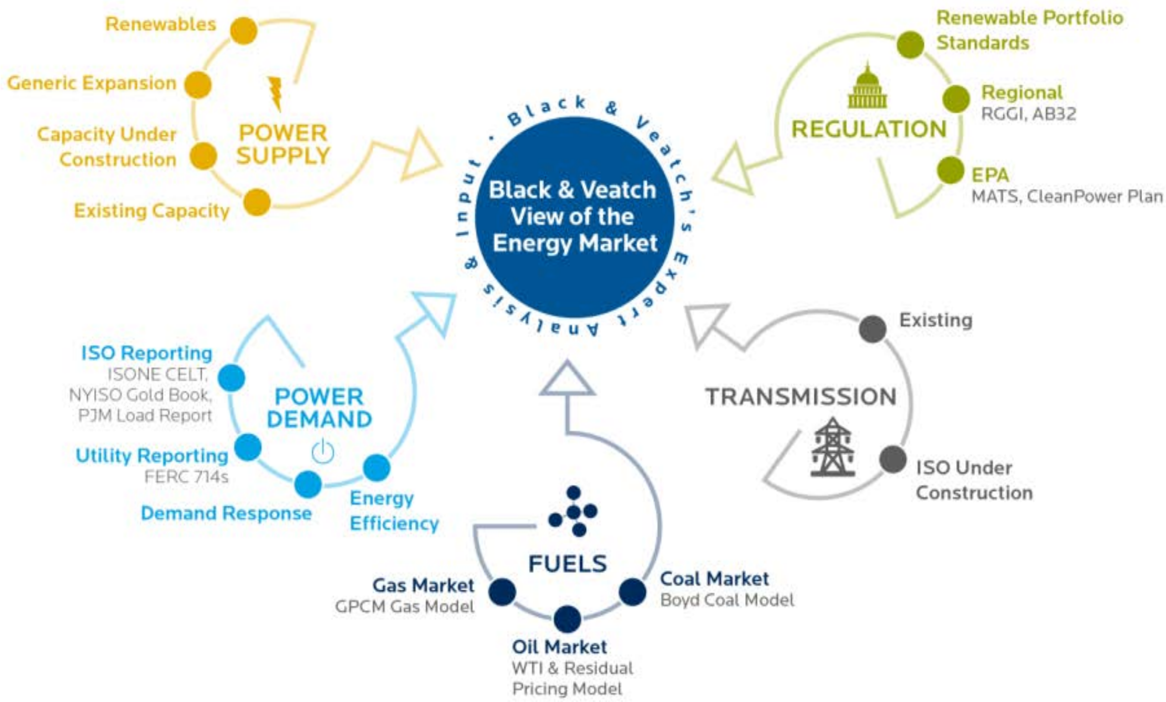

Figure 4-5 Black & Veatch's Integrated Market Modeling Process

Black & Veatch's fundamental modeling base case assumption anticipates federal regulatory action to address CO_2 emissions and GHG pollution. That assumption contributes to higher natural gas prices because it increases projected natural gas demand for electricity generation. It also contributes to a projected increase in electricity prices in 2022, when GHG rules are projected to first begin to take hold. The assumed GHG regulations would build off of and expand emissions limitations compared to the current AB 32 regulations in place in California.

The combination of fundamental assumptions characterized above was used to develop the market price forecast of California and Western US electricity prices. These forecast prices provide a benchmark against which to evaluate SFPUC supply resource options and also a benchmark to characterize short-term to intermediate-term market purchase options. The forecast prices were also used to value excess energy market purchase and sale activity for SFPUC. **Figure 4-6** illustrates the historic and forecasted energy prices for northern California. Forecasted prices follow a cyclical pattern due to seasonal demand in California; prices tend to be higher during peak summer season.

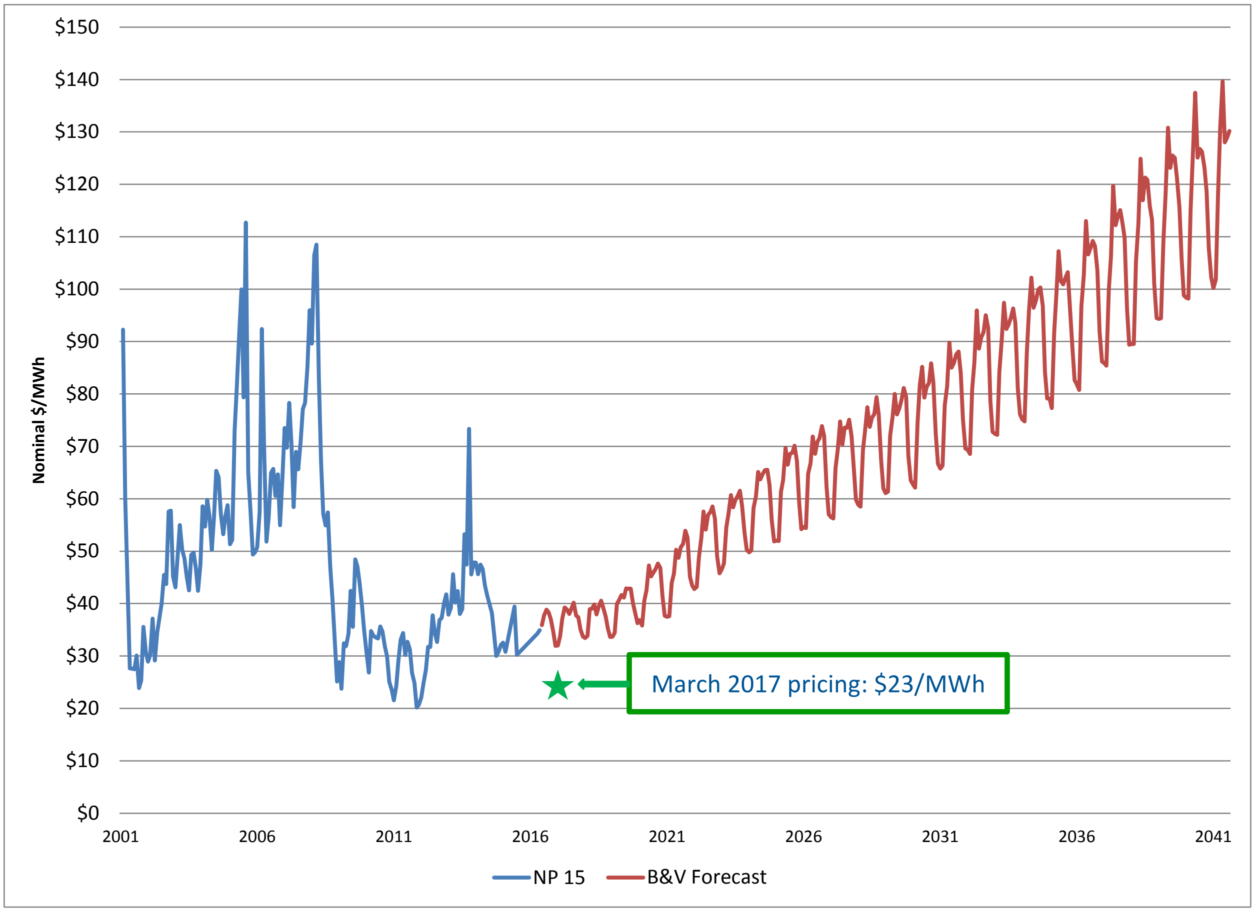

Figure 4-6 Northern California Actual and Forecasted Average Monthly Market Prices

As can be seen above from the historic price information, the actual market prices can vary wildly and are difficult to predict with any certainty. While Black & Veatch has used all available market information to develop a reasonable projection for planning purposes, the actual prices could differ from these forecasts. Due to this uncertainty, a range of different market prices were tested as sensitivities during the analysis; the results of these tests will be shown in Section 6.

Some adjustments to the estimates above were made to the short-term projections entered into PLEXOS for market prices given recent SFPUC market transactions and expected hydroelectric generation levels. As an example, market power prices witnessed by SFPUC averaged $23/MWh during the first two weeks of March 2017 due to the high levels of hydroelectric generation being produced in California.

The pricing forecasts performed by Black & Veatch reflect the impact of considerable solar PV entering the California market. As a reflection of this impact, **Figure 4-7** shows the average hourly prices by month in 2030. Prices are forecasted to drop considerably during the middle of the day when solar PV generation is at its peak, then ramp in the late afternoon when load grows and solar PV generation drops off. Each line on the figure shows the different months; ***spring is forecasted to have the lowest prices due to the high level of hydroelectric generation coupled with relatively low load.*** These differences in monthly and hourly prices are especially important for SFPUC due to its generation portfolio and water-first requirements.

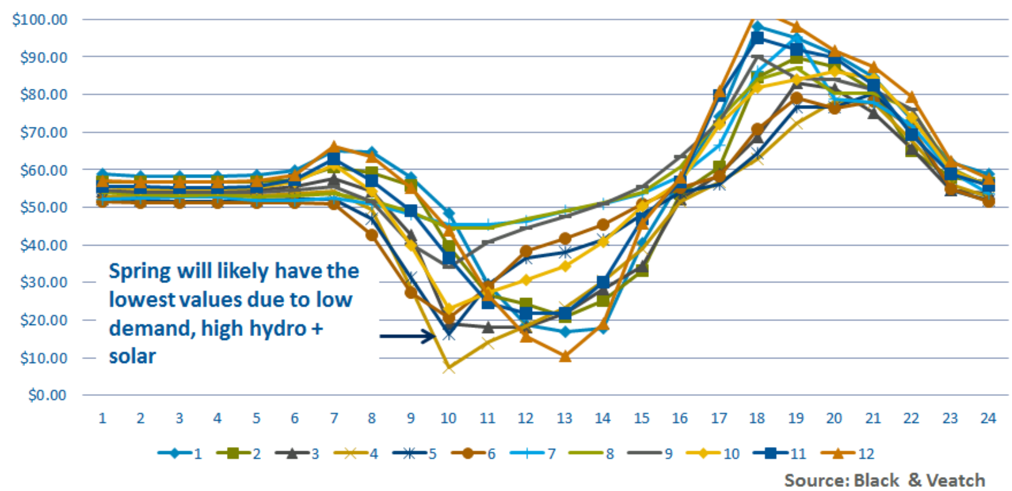

Figure 4-7 **Average 2030 Hourly NP15 Market Prices, By Month**

Pricing forecasts were included for PCC3 or "unbundled" RECs as part of the IRP modeling. Per their alternative RPS compliance obligation, SFPUC can purchase PCC3 RECs for market purchases if the level of RECs generated by the Hetch Hetchy system is not sufficient to meet load. Based on analysis performed by Black & Veatch, California and much of the Western US is forecast to be long on unbundled RECs, leading to oversupply throughout the analysis period. Thus, a price similar to what is currently seen in the market of $1/MWh was assumed for any PCC3 REC purchases.

4.6 WORKING GROUP 5 - ELECTRIC DEMAND

SFPUC serves, on average, a maximum demand of 150 MW and total annual consumption of approximately 980,000 MWh, not including the wholesale customers (largely Modesto Irrigation District and Turlock Irrigation District). Depending on hydrological conditions, Hetch Hetchy generation typically produces more generation than what is needed for SFPUC demand. Any shortfall is met with purchases from the California Independent System Operator (CAISO).

The IRP study focused on existing retail load and current redevelopment load growth. This study also developed a high load growth scenario that included ***additional load resulting in approximately 300 MW of load by 2040***. It should be noted that this IRP does not focus on the potential for swings in hourly and seasonal price differentials and shapes caused by changes in load shape and generation profiles from current conditions. This topic could be assessed in the future if a large amount of this projected load growth is realized. **Figure 4-8** shows the SFPUC peak load forecast under the Base Case and sensitivity scenarios.

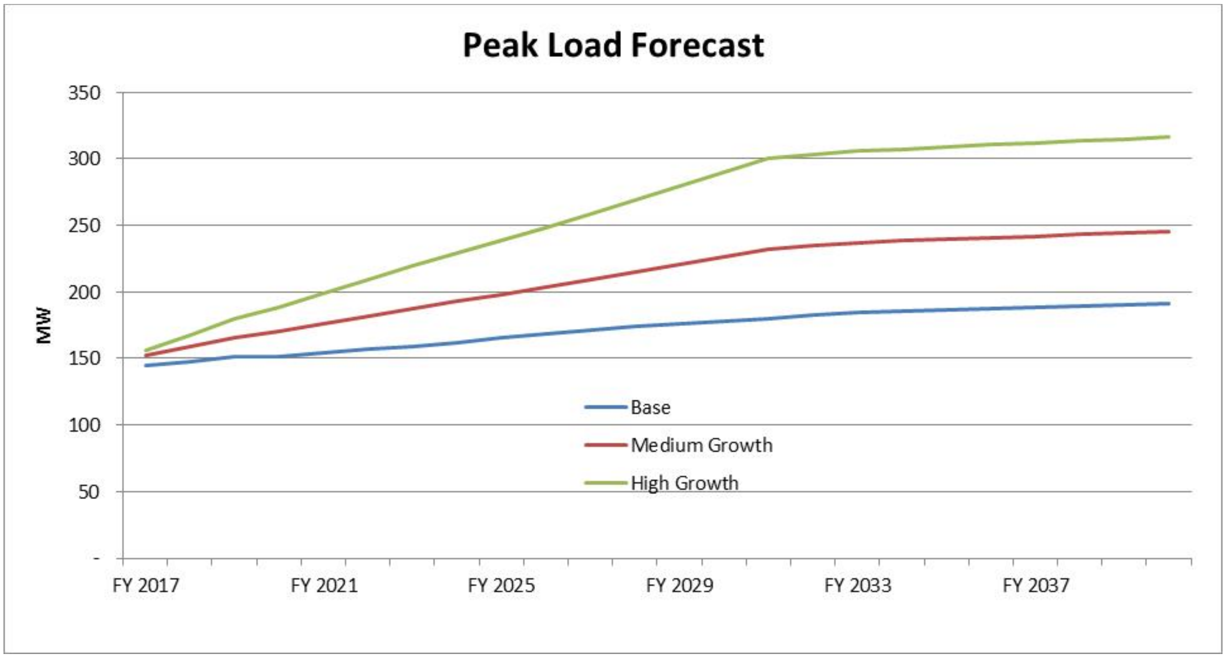

Figure 4-8 SFPUC Peak Load Forecast

The yearly SFPUC peak demand and net energy demand for the Base Case and high load scenarios are illustrated in **Table 4-8**.

Table 4-8 SFPUC Demand Forecast

FISCAL YEAR	BASE PEAK (MW)	BASE ENERGY (GWH)	HIGH LOAD PEAK (MW)	HIGH LOAD ENERGY (GWH)
2017	144	979	156	1,029
2018	146	990	166	1,079
2019	148	1,006	176	1,129
2020	151	1,017	189	1,179
2021	153	1,035	197	1,230
2022	156	1,051	208	1,280
2023	158	1,067	218	1,330
2024	161	1,084	229	1,380
2025	165	1,109	239	1,430
2026	169	1,132	249	1,481
2027	172	1,148	259	1,531
2028	174	1,164	269	1,581
2029	176	1,178	280	1,631
2030	178	1,190	291	1,681
2031	181	1,206	301	1,732
2032	184	1,212	304	1,740
2033	186	1,218	307	1,749
2034	187	1,224	308	1,758
2035	188	1,230	310	1,766
2036	188	1,236	311	1,775
2037	189	1,243	313	1,784
2038	190	1,249	315	1,793
2039	191	1,255	316	1,802
2040	192	1,261	318	1,811

Source: SFPUC & Black & Veatch

SFPUC offers a number of energy efficiency and renewable energy programs to its customers that were taken into consideration as part of the resource plan. DER policy obligations, including EE and customer-sided PV generation, were reflected in net load growth assumptions of 0.5 percent per year consistent with previous SFPUC work on DER impacts and policy requirements. DER scenario assumptions were also developed to evaluate the impact of higher DER penetrations based on work performed by Black & Veatch and the SFPUC. This high DER case would add an additional 5 MW of customer sided solar PV, an increase in energy efficiency which would decrease 2040 load by 4.8 percent, and 1200 city electric fleet vehicles (which would add roughly 8,000 MWh of load).

This Working Group also discussed future storage needs for purposes of IRP modeling. While SFPUC is engaging in small-scale battery storage pilot projects for local system resiliency projects, evaluation of those impacts are outside the scope of this IRP. In addition, the existence of predominantly large hydroelectric generation units on the SFPUC system could act as a considerable storage mechanism for being able to meet future load shape demand, depending on the water-first dispatch requirements. Given the low level of variable generation on the SFPUC system and an appropriate level of flexible capacity and resource adequacy, no additional storage cases were run as part of the analysis.

4.7 WORKING GROUP 6 - POLICY

Over the past several years, legislative and regulatory activity at the federal, state, and local levels have redefined the electric utility industry. This section describes many of these key actions, the impact they have had, and how the SFPUC Power Enterprise must accommodate them in future planning actions. WG6 identified the key policies to be included as part of the IRP process to assure that SFPUC is meeting relevant obligations.

4.7.1 State Greenhouse Gas Reduction Goals (Assembly Bill 32 and Senate Bill 32)

Assembly Bill 32 (AB 32, 2006) set a goal for GHG emissions in California to be reduced to 1990 levels by 2020. To achieve these goals the California Air Resources Board (CARB) adopted a Scoping Plan identifying a number of programs to reduce GHG emissions. This included a cap-and-trade program utilizing a “market approach” whereby a limited number of GHG production/emanation allowances (certificates) are issued annually and awarded and/or sold to carbon-intensive industries. The number of allowances issued is reduced each year creating incentives for businesses to reduce their GHG emissions and/or trade to meet their compliance obligations. The full implementation of AB 32 will help mitigate risks associated with climate change, while improving energy efficiency, expanding the use of renewable energy resources, encouraging cleaner transportation, and reducing waste. AB 32 has been augmented by Senate Bill 32 (SB 32) and AB 197 (2016), which legislates a new target of reducing carbon dioxide (CO_2) levels 40 percent below 1990 levels by 2030.

The SFPUC does not have a compliance obligation under AB 32 or SB 32. As part of its Renewable Portfolio Standards (RPS) compliance, SFPUC generates power from 100 percent GHG free resources. The SFPUC does not own any fossil fueled resources subject to the GHG regulations, nor does it directly purchase any energy from out-of-state that triggers a compliance obligation.

4.7.2 Senate Bill 350, Renewable Portfolio Standards

In the fall of 2015, California legislators passed Senate Bill 350 (SB 350), which mandates California utilities to procure 50 percent of their electricity from eligible renewable resources by 2030. The legislation includes interim targets for 2024 and 2027 and requires doubling of energy efficiency for existing buildings. SB 350 was designed to help California meet the long-term goal of an 80 percent reduction of GHG by 2050.

The SFPUC meets RPS compliance through an alternative compliance obligation (Public Utilities Code Sec. 399.30[j]). According to this statute, the SFPUC must meet 100 percent of its retail sales with either qualifying Hetch Hetchy hydroelectric generation or RPS eligible resources. This alternative obligation will be permissible for compliance as long as the Hetch Hetchy hydroelectric system meets at least 67 percent of the SFPUC's electricity demands with eligibility being determined at the start of each RPS compliance period based on the previous 20 years of hydroelectric generation and electricity demand. For market power purchases, the SFPUC may use renewable energy credits (RECs) from any Portfolio Content Category (PCC) to meet its compliance obligation if sufficient RECs are not generated by the Hetch Hetchy Power System and the SFPUC's other RPS-eligible generation.

Generation from the KPH can be counted as either qualifying Hetch Hetchy generation or RPS-eligible generation. Therefore, surplus KPH generation is a PCC1 (bundled) REC that can be carried forward for use in future years for the SFPUC's RPS compliance. The SFPUC can also sell up to 100,000 PCC1 RECs from its KPH generation to others over the life of the asset. Surplus RECs from the SFPUC's other RPS-eligible resources may also be carried over for future use or sold to others.

4.7.3 Energy Storage Assembly Bill 2514

California Assembly Bill 2514 (AB 2514) required that California utilities evaluate the potential to procure viable and cost-effective energy storage systems and that the governing bodies of local publicly-owned utilities set appropriate procurement targets, if any, by October 1, 2014, for energy storage systems to be procured by benchmark dates of December 31, 2016, and December 31, 2021.

SFPUC completed its 2014 report to the California Energy Commission (CEC), along with a 2015 update, both of which determined that storage was not a cost-effective resource option for the SFPUC, primarily because the Hetch Hetchy Power System provided many of the same benefits of storage (e.g., load-shifting, ancillary services, flexible ramping, etc.). The SFPUC will be moving forward with small-scale energy storage demonstration projects in San Francisco for local system resiliency efforts,

4.7.4 Raker Act

The 1913 Raker Act provides unique rights, obligations, and requirements for building the hydro system, benefiting San Francisco, and providing power at cost to the Modesto Irrigation District (MID) and Turlock Irrigation District (TID). Generation in excess of SFPUC municipal load must be offered at cost to MID and TID to meet their "Class 1" (i.e. municipal and water pumping needs) Load before the CCSF can meet its other customer demands or sell to third parties. Any surplus energy left after meeting customer obligations is sold on the Western System Power Pool market. MID and TID have no obligation to buy power from the SFPUC and can choose instead to buy power from the wholesale market.

Another aspect of the Raker Act is that the SFPUC is obligated to produce a minimum amount of power from the Hetch Hetchy Power System (45 MW), according to Section 9M. No cases evaluated by the IRP reduced hydroelectric generation below this level.

4.7.5 San Francisco Electricity Resources Plan

The 2011 Electricity Resource Plan adopted by SFPUC and the San Francisco Board of Supervisors mandated that power sold to customers from the SFPUC be 100 percent GHG free as part of San Francisco's broader goal of achieving a 100% GHG-free electric system (regardless of provider) by 2030. All portfolios evaluated as part of this IRP met this requirement, either through hydroelectric resources, other renewable energy generation resources, and/or market purchases coupled with PCC3 RECs as needed.

4.7.6 AB 1823 and Water First Policy

California Water Code Section 73504[b] states the following:

In order to supply adequately, dependably, and safely the requirements of all users of water, the city shall continue its practice of operating the reservoirs in the Counties of Tuolumne and Stanislaus in a manner that ensures the generation of hydroelectric power will not cause any reasonably anticipated adverse impact on water service. The city shall assign higher priority to delivery of water to the Bay Area than to the generation of electric power, unless the Secretary of the Interior, in writing, notifies the city that doing so would violate the Raker Act (63 Public Law 41).

In addition, AB 1823 (2002) requires that the SFPUC "operates its reservoirs in Tuolumne and Stanislaus Counties such that water delivery is the first priority and hydroelectric power generation is second." To abide by these requirements, the operations team on the Hetch Hetchy Power System played an integral part in this analysis by providing system operations data that reflect these constraints. Daily and yearly output profiles from each of the three powerhouses were applied in the IRP modeling to reflect typical hydroelectric output after the obligations of the above requirements are met.

5.0 IRP Modeling Methodology

5.1 PRODUCTION COST MODELING

The basis for the system analysis is the PLEXOS production cost model. PLEXOS is an industry standard, tried-and-true simulation software that uses state-of-the-art mathematical optimization, combined with the latest data handling and visualization and distributed computing methods, to provide a high-performance, robust simulation system for electric power systems.

The following are features of the PLEXOS system applied as part of the IRP analysis:

- *Capacity Expansion Planning: For the scenarios developed, PLEXOS optimized electric power generation, transmission line usage, and constraints over long time frames using mixed integer programming.*
- *Power Generation: Dispatch and operate generation resources within defined technical limits including, but not limited to, minimum operating levels, minimum up and down times, ramping rates, startup and shutdown profiles, and operating modes.*
- *Transmission: Generation economic dispatch and unit commitment is fully integrated with the constraints of the SFPUC transmission system. Key factors such as system losses, interface limits, wheeling charges, automatic aggregation of network areas, and optimal transmission switching can be utilized by the PLEXOS model.*
- *Ancillary Services: The model took into account ancillary service needs co-optimized with generation dispatch and unit commitments.*
- *Objective Functions and Models of Competition: For cases where hourly market optimization was allowed, the model maximized objective functions, e.g., price-based unit commitment, to maximize profit while staying within defined system constraints.*

After key system parameters as defined by the working groups were input, a series of scenarios were defined to model different potential futures for the SFPUC power system. Each scenario was modeled from 2016 to 2040 to develop an understanding of the system costs and identify any operational issues caused by market pricing, load, or policy constraints. Detail on the scenarios modeled in the analysis is outlined in the next section.

5.2 PLANNING SCENARIOS

SFPUC's primary resource planning decision focused on an optimal mix of supply resources and providing direction for future investment in capacity. To assess the different risks and cost profiles of available technologies and resource options, a number of scenarios were examined in evaluating SFPUC's resource planning decisions. **Table 5-1** highlights key assumptions used in developing the planning scenarios. The three scenarios described demonstrate the main investment options SFPUC evaluated as part of the IRP study.

Table 5-1 Main Planning Scenarios

SCENARIO	DESCRIPTION
1	All necessary investment plans to be maintained to keep the current level of hydro generation through year 2041.
2	Only funded investment projects in the current capital plan to be supported and unfunded projects to be delayed until Years 11 through 25 of the analysis.
3	MPH to be deferred for the period of the study and the energy to be replaced with market purchases and renewable resources to serve load as needed.

Screening portfolios were developed to isolate specific technologies to determine the cost competitiveness with the business as usual conditions. Following the base case resource cases, a set of sensitivities were run on the most attractive scenarios to gauge the impact of changes on key inputs.

The scenarios and sensitivities outlined in **Table 5-2** were run as part of the analysis. The scenarios and sensitivities run by PLEXOS were either with real time trading or without to best reflect the actual SFPUC operations. The without real time trading scenarios reflected current operations (typical of many small utilities), assuming excess generation would be sold when the system is long and purchased when the system is short, with no optimization to take advantage of hourly market prices. On the other hand, the real time trading scenarios and sensitivities reflect a hypothetical change in operations such that swings in inter-day market prices can be monetized through the hydroelectric system by changing production levels to maximize output when prices are high and minimize when prices are low. The cases that include intermittent resources (wind and solar) do incorporate real time optimization to reflect how the system would need to operate if these resources were incorporated.

Table 5-2 Planning Scenarios and Sensitivities

SCENARIOS/SENSITIVITIES	DESCRIPTION	USE OF PLEXOS AND OPERATING CONDITIONS
Scenarios 1, 2, and 3	Base case scenarios with different investment plans assumptions.	PLEXOS – No Real Time Trading
Inclusion of renewable resources	50 MW of wind, solar and geothermal were added to the generation mix in MPH deferment scenarios	PLEXOS – With Real Time Trading
Scenarios 1 and 3 with high load growth	High load growth of 300 MW by 2040	PLEXOS - No Real Time Trading
Inclusion of renewable resources with high load growth	50 MW of wind energy in combination of high load growth	PLEXOS - With Real Time Trading
Wet and dry hydro generation years	Impact of wet and dry years in 2025 were evaluated for an assessment of their risk profile	No PLEXOS Modeling
Alternative market prices for gas and power	Higher market prices were developed to evaluate the impact on Scenarios 1 and 3	No PLEXOS Modeling

5.3 DATA ANALYSIS

The analytics performed for this IRP examined costs, environmental impacts, and reliability of each strategy. Validation of the methodology and execution of the model runs were accomplished through comparison of results with internal peer groups, manual spot checks, and discussions with SFPUC staff to verify the results. Modifications of modeling approaches and scenarios were made as appropriate to ensure that the models adequately reflect the current state of SFPUC system operations and likely future operations scenarios.

After the raw data from the PLEXOS model were downloaded, a "scorecard" was created to summarize the key items that impact the system NPV. The main items are as follows:

- ***Market Sales Revenues and Cost:*** *The base case scenarios reflect current SFPUC water-first operations where scheduling is performed in the day-ahead market. SFPUC buys power if short to meet load obligations and sells if long, with no real time optimization to reflect market pricing. As mentioned above, certain sensitivity cases did examine the value of a future where real time scheduling is deployed.*
- ***Ancillary Services Costs:*** *The cost to purchase additional ancillary services (as needed) to meet system demands.*
- ***Sunset and Other PPA Costs:*** *The PPA costs for other generation resources purchased by the SFPUC are included in the NPV. In the base case scenarios, this cost is only the 5 MW solar PV PPA at Sunset Reservoir; the sensitivity cases where additional solar, wind, and geothermal resources are added to the generation mix have their costs added to this line item.*
- ***REC Costs:*** *Any REC purchases required to meet RPS and GHG free obligations. It was assumed as part of the analysis that any excess RECs generated by the hydroelectric system would have little value and not affect future investment decisions.*
- ***HHWP Capital and O&M:*** *The EAA costs developed as part of the CAM for each scenario represented the largest overall line item in the scorecard.*
- ***System and Local RA Requirements:*** *Using the defined RA needs indicated in CAISO guidelines and the generation profile of the resources used in each case, any additional RA purchases needed in each scenario were calculated. Black & Veatch assumptions for future RA costs were applied to develop the estimates.*
- ***CAISO T&D Costs:*** *Costs associated with the transmission and distribution fees, based on the overall system load.*

In addition to the economic factors, other considerations need to be taken into account when deciding which scenarios are most attractive. The main items defined for SFPUC were the following:

- ***Environmental****:* *Is there a considerable difference in the environmental impact between the scenarios?*
- ***Policy Compliance and Uncertainty****:* *Do each of the scenarios meet the intent of federal, state, and local policies for SFPUC operations? Could potential changes in future compliance obligations unduly impact any scenario?*

- ***System Reliability****: While all scenarios meet minimum system reliability requirements, could any scenarios face concerns if system conditions change?*
- ***Market Risk****: Would significant changes in market conditions, such as power prices or overall load, unduly place certain scenarios at a considerable disadvantage?*
- ***Ownership Considerations****: To what level would the SFPUC become more dependent on third-party supply to meet future load obligations?*

Section 6.3 discusses how the different scenarios and sensitivities ranked with regard to these qualitative factors.

6.0 Portfolio Results

As noted in Section 5.2, three main scenarios were analyzed by the PLEXOS model to determine the net system cost to reliably meet load, which is one of the key metrics for comparison between scenarios. This section outlines the results of the PLEXOS modeling for the three base case scenarios, presents the results of the sensitivity analysis, and lists key qualitative factors that also need to be taken into consideration when defining the appropriate path forward.

6.1 BASE CASE ANALYSIS

To provide context for the hydroelectric generation units available to the SFPUC to meet load obligations, the level of generation available from each unit, and the cost by unit, a series of graphics was created demonstrating how the SFPUC would preferentially dispatch to meet load for each scenario. Although this does not reflect how the SFPUC truly operates because it is a water first utility, the graphics are useful for understanding the value of each unit in meeting load. The use of graphics is consistent with how most electric utilities evaluate the economics of generation.

Figure 6-1 shows the results for Scenario 1. Each stacked bar represents generation from the three hydroelectric units over the analysis period, with the average cost of generation from each. The black line represents forecasted base load, which is expected to slowly increase over time.

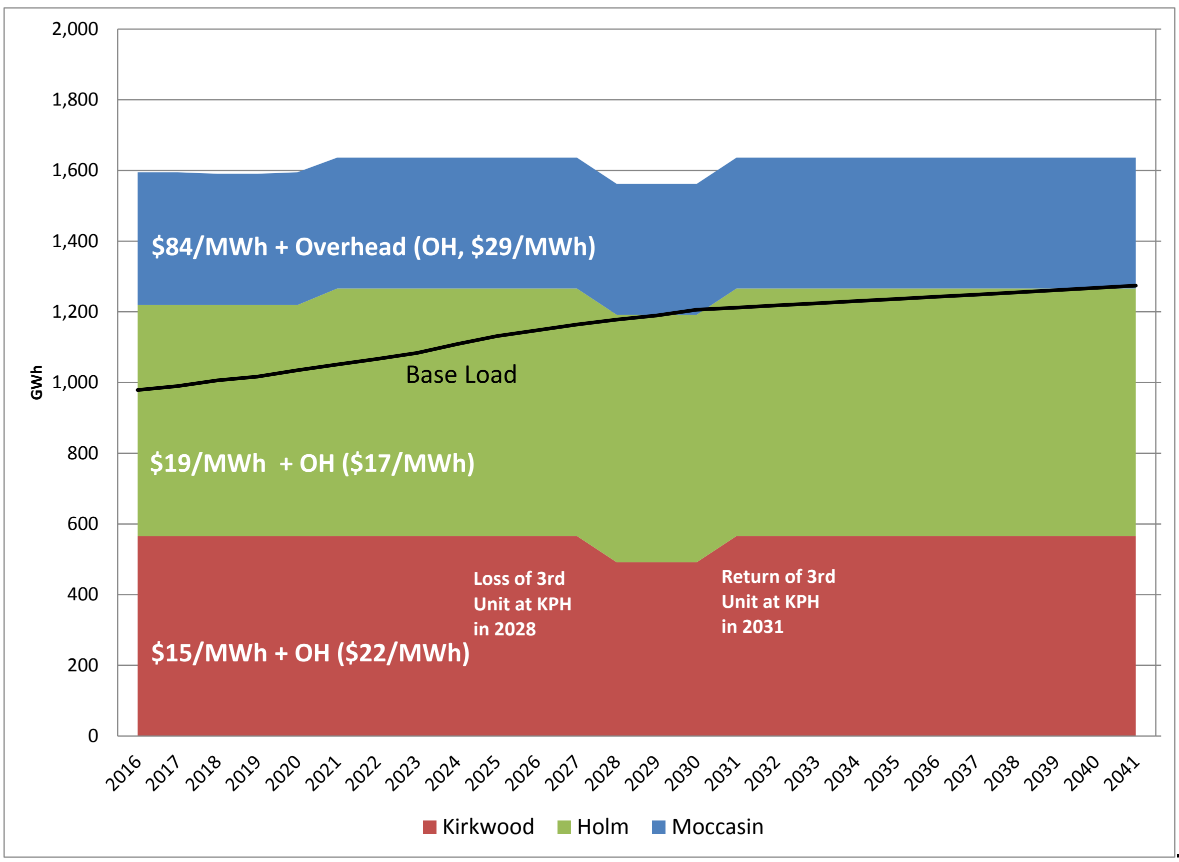

Figure 6-1 Scenario 1 Dispatch

As noted at the outset of this report, the SFPUC is generation long and a net exporter of power. This can be seen quite clearly from Figure 6-1, which shows that generation from KPH and HPH are sufficient to meet the average yearly base case load throughout the analysis period.

Any generation above that needed to meet load is sold in the open market. While yearly average market pricing is currently near the $35-40/MWh total cost of generation from KPH and HPH, generation from MPH is generally uneconomical for market sales as can be seen on **Figure 6-2**. In this figure, the red line represents the forecasted annual average market sales price, while each of the lines for the powerhouses represents their average annual cost of generation with overhead from Scenario 1 included. Market sales price takes into account forecasts for when SFPUC will be selling into the market, and are lower than the annual average forecasted market prices in Section 4.5. Powerhouse costs fluctuate some over the analysis period due to different capital and operating investments that are incurred over the analysis period.

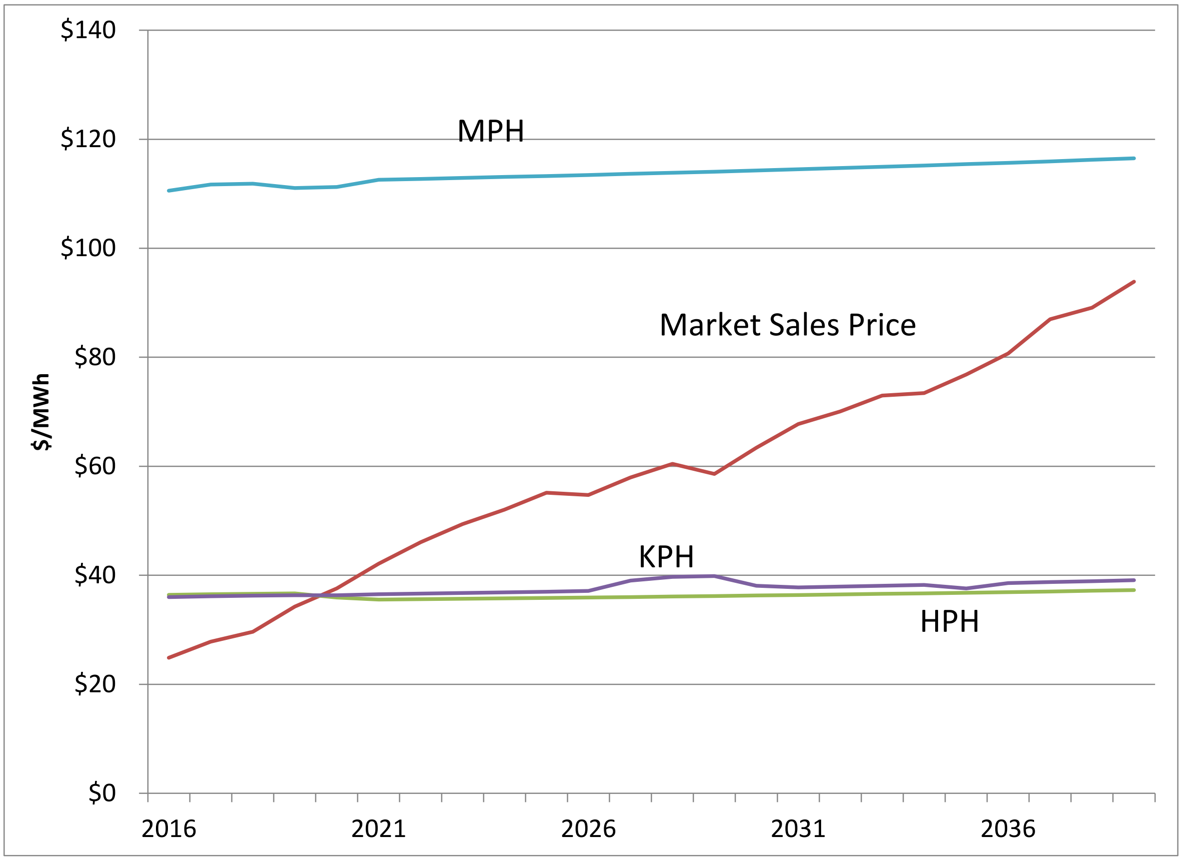

Figure 6-2 Hetch Hetchy Unit Cost of Generation (with Overhead) versus Market Price

As can be seen, both Kirkwood and Holm become breakeven with the forecasted market price in 2020, while Moccasin remains above market value throughout the IRP analysis period. Section 4 showed that historic NP15 market prices have fluctuated considerably over the last 15 years, but have been reasonably stable since 2010 with the only appreciable price spikes seen in the winter of 2014 due to high natural gas prices. **Table 6-1** below shows the average NP15 market price since 2010.

Table 6-1 Average NP15 Market Prices, 2010-2016

YEAR	AVERAGE PRICE ($/MWH)
2010	36
2011	29
2012	28
2013	41
2014	47
2015	33
2016	33

Due to the expectation that natural gas prices will remain relatively low in the short-term and that energy demand in California will continue to be flat, this gives support to the view that average wholesale power prices will remain below $40/MWh for this decade. ***Sales of excess power to the market from Kirkwood and Holm will remain breakeven at best, while sales from Moccasin will continue to be uneconomic.*** This represents a change from the 2000-2010 timeframe when wholesale market prices were much higher due largely to more expensive natural gas and renewable energy options. Prices at that level are not expected to return for 10 years or more, meaning that existing assets will likely be operating in a low market price environment which must be taken into account when evaluating near-term investment options.

The results from the dispatch analysis for Scenario 2 can be seen on **Figure 6-3**.

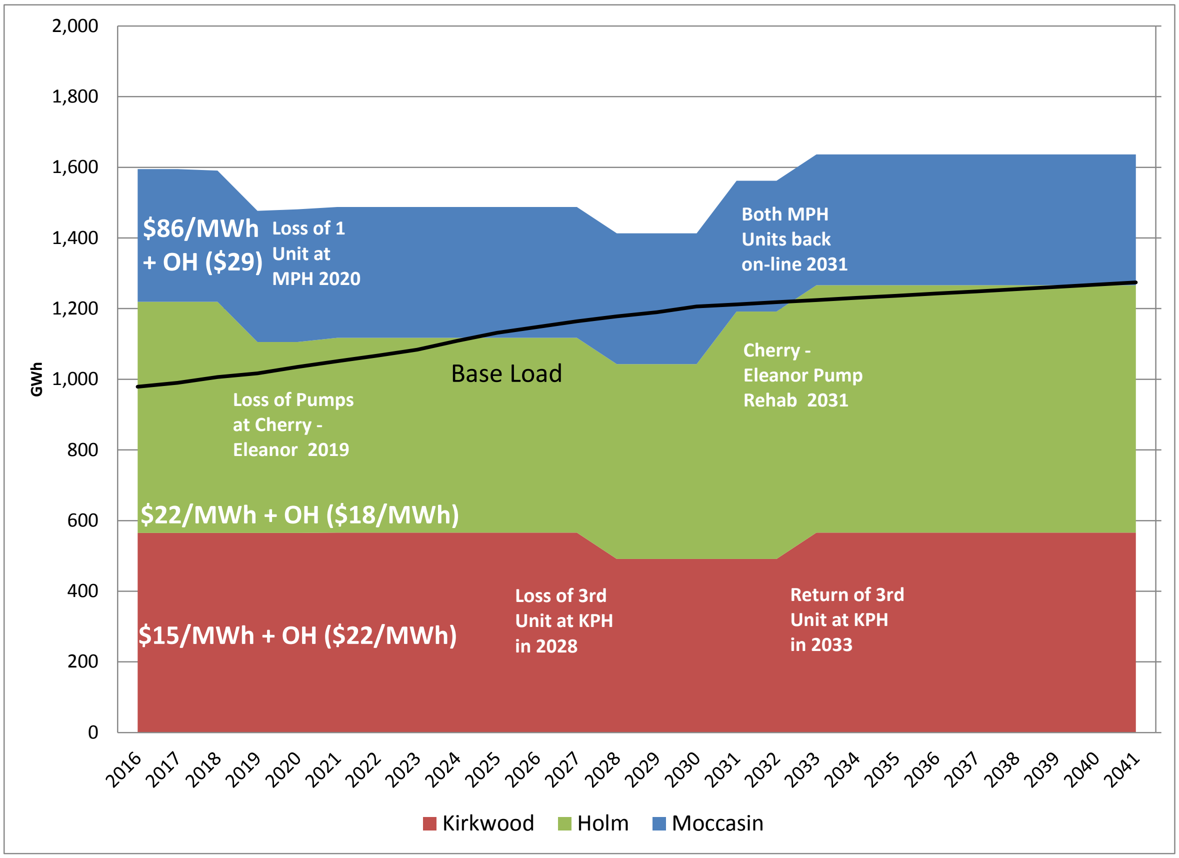

Figure 6-3 Scenario 2 Dispatch

Scenario 2 has less overall generation than Scenario 1 because of the deferral of a number of capital improvement projects until later in the analysis period. Thus, generation from MPH and HPH is lower in the 2019 through 2031 time frame. This leads to a larger portion of MPH power being used to meet load instead of being sold into the market when compared to Scenario 1.

The results from the dispatch analysis for Scenario 3 can be seen on **Figure 6-4**.

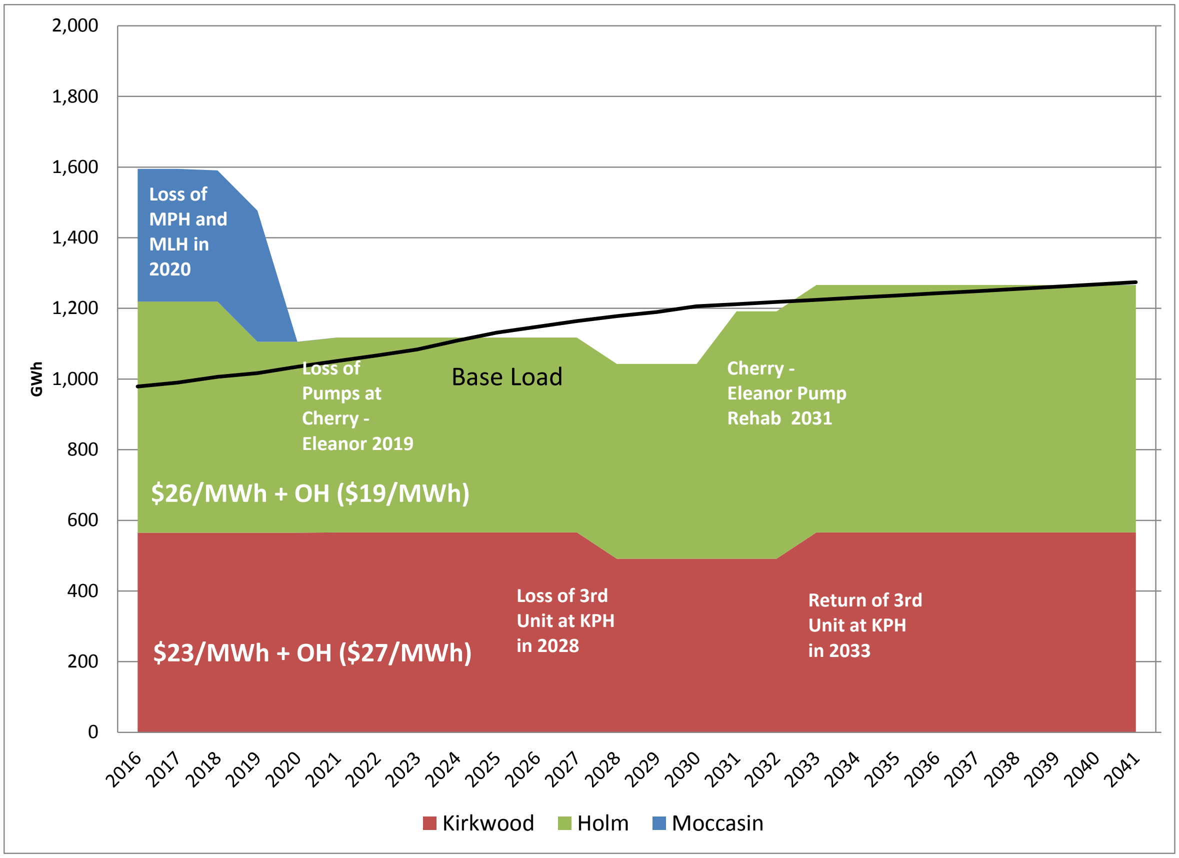

Figure 6-4 Scenario 3 Dispatch

Scenario 3 has the same level of generation at KPH and HPH as Scenario 2, but no generation from MPH after 2020 because of the assumption that the necessary capital improvements to keep this Powerhouse operational would be deferred until after the IRP analysis period. Reducing the generation level to this degree places the power supply and demand in much closer balance than in the previous two scenarios. Any generation shortages to meet load requirements are met through market purchases. The cost of generation for KPH and HPH in this scenario is higher than the previous scenarios because of the allocation of costs previously assigned to MPH are switched to the other Powerhouses.

One clear conclusion identified after running the three base case scenarios is that generation from HPH and KPH should be maximized because of their lower cost. If SFPUC has excess generation from these units for meeting load, the excess can typically be sold in the market at a profit on average over the course of the analysis period (although current prices with overhead costs are above market value). Since Scenario 1 reflects this in the generation inputs for these units, a similar assumption was made in the final economic analysis of the cases below for the other scenarios to allow comparisons on a common basis.

The scorecards developed for each of the cases from the PLEXOS model can be seen in **Table 6-2**. Non-zero entries are listed, with each reflecting the NPV value of the stream of cash flows for each major economic metric over the 25 year analysis period. In the IRP analysis, the goal is to minimize overall costs, thus lower NPV results are better. The intent of this comparison is to identify the relative differences between the scenarios; it is not representative of the full cost to Power Enterprise to meet load with the modeled resources.

Table 6-2 PLEXOS Base Case Scorecard Results (NPV, $MM)

	SCENARIO 1	SCENARIO 2	SCENARIO 3
VARIABLE COSTS BY CASE			
Hetch Hetchy Capital Costs	641	648	303
Market Sales Revenue*	(397)	(358)	(270)
Market Purchase Cost*	73	94	211
Hetch Hetchy O&M Costs	95	95	91
SAME COSTS REGARDLESS OF CASE			
CAISO T&D Costs	551	551	551
Local/Flex RA Costs	76	76	76
Sunset PPA Costs	30	30	30
TOTAL			
25 Year NPV Costs	**1,069**	**1,135**	**991**
* Based on base case market price forecast; will change based on actual market prices. See sensitivity analysis in the following sections which showed a range of +/- 20 percent.			

The largest differences between the cases come from Hetch Hetchy capital costs (costs required for continued Powerhouse operations) and the market sales/purchases. Some of the metrics do not change regardless of the scenario. For example, the Sunset solar PV PPA costs do not change; the RA costs are the same in all cases even with the deferral of the MPH in Scenario 3; and the transmission and distribution costs that SFPUC must pay are based on load, not generation resources.

Market purchases and sales are significantly different in Scenario 3 because of the deferral of MPH investments. While Scenarios 1 and 2 show considerably more market revenue than costs because of excess generation, this revenue is only obtained as a result of the additional investment made in the Hetch Hetchy system (leading to higher capital costs). As mentioned in Section 4.0, the base case Scenarios were modeled without hourly real time dispatch to reflect current SFPUC daily operations. Most sales occur during the spring hydro runoff period when prices are lowest in the CAISO market, and most purchases occur in the fall when prices are higher. Since the PLEXOS model has forecasts for pricing for each hour of the year, the differences in market sales and purchase price throughout the analysis period can be identified; these are shown in **Table 6-3**.

Table 6-3 Weighted Average Market Power Sales and Purchases Prices ($/MWh)

	SCENARIO 1	SCENARIO 2	SCENARIO 3
Avg. Market Sales Price	57	58	53
Avg. Market Purchase Price	84	80	84

The other major item that impacts the NPV of each case is the capital cost. As outlined in Section 4.2, the capital investment for Scenarios 1 and 2 are considerably higher largely because of the costs associated with investments in the Mountain Tunnel and Line 3/4 Projects, which will support MPH operations.

Scenario 2 was found to be uneconomical relative to Scenarios 1 and 3 in all versions explored in the PLEXOS modeling. This scenario costs more than Scenario 1 (because deferrals of capital investments lead to inefficient maintenance procedures) for less generation, which lead to higher overall generation costs on a $/MWh basis. Therefore, future case comparisons and sensitivity analyses use only Scenarios 1 and 3.

Figure 6-5 shows the NPV for Scenarios 1 and 3 categorized into four major areas: Capital Costs, O&M Costs, Net Market Revenues (taking into account both purchases and costs on the wholesale market), and Other Costs, which entails the costs to Power Enterprise that are largely unchanged regardless of the case. Capital and O&M costs to Power Enterprise are $342MM higher in Scenario 1; while Scenario 1 also has higher market revenues of $264MM over the analysis period, this revenue is not enough to offset the additional expenditures. Taking all these items into account, Scenario 3 has an NPV that is $78MM lower.

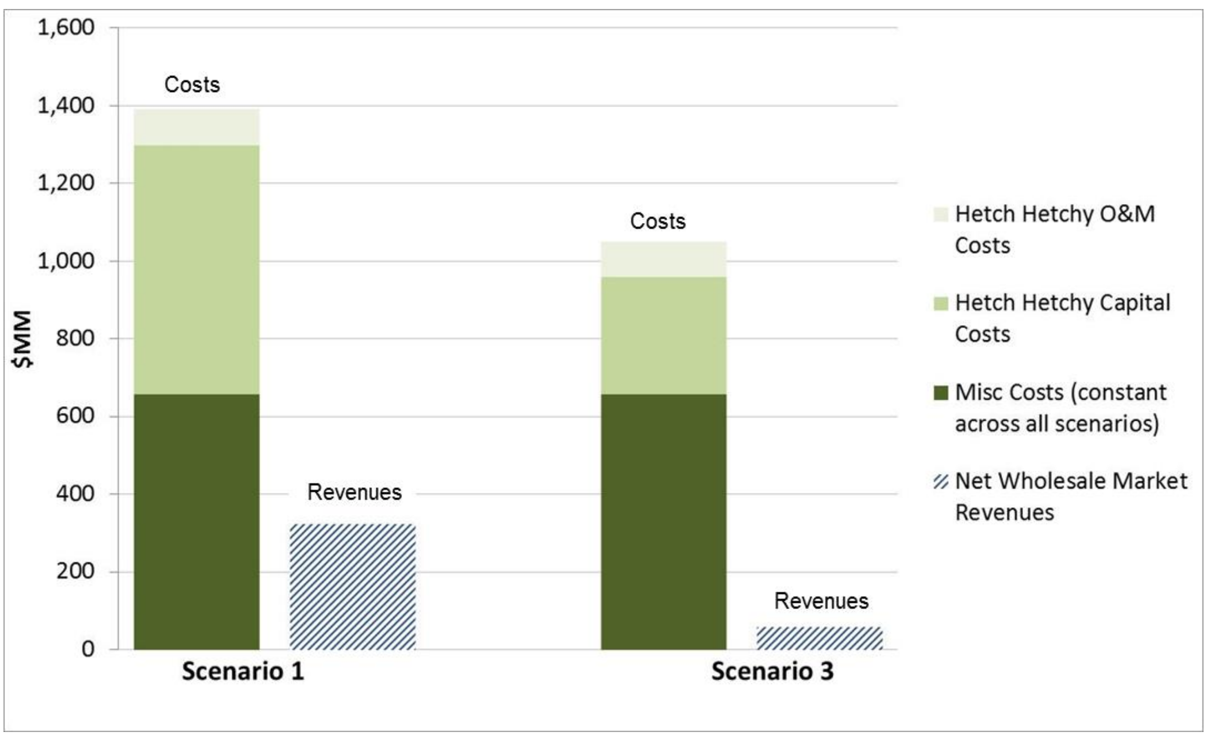

Figure 6-5 NPV Results, Scenario 1 versus Scenario 3

Figure 6-6 shows the cumulative NPV for Scenarios 1 and 3 over the analysis period for select scorecard items, along with the difference in cumulative NPV. To more clearly show the difference in NPV between the scenarios, only the items that differed between the cases (capital costs, O&M costs, and market sales/purchases) were included in this figure.

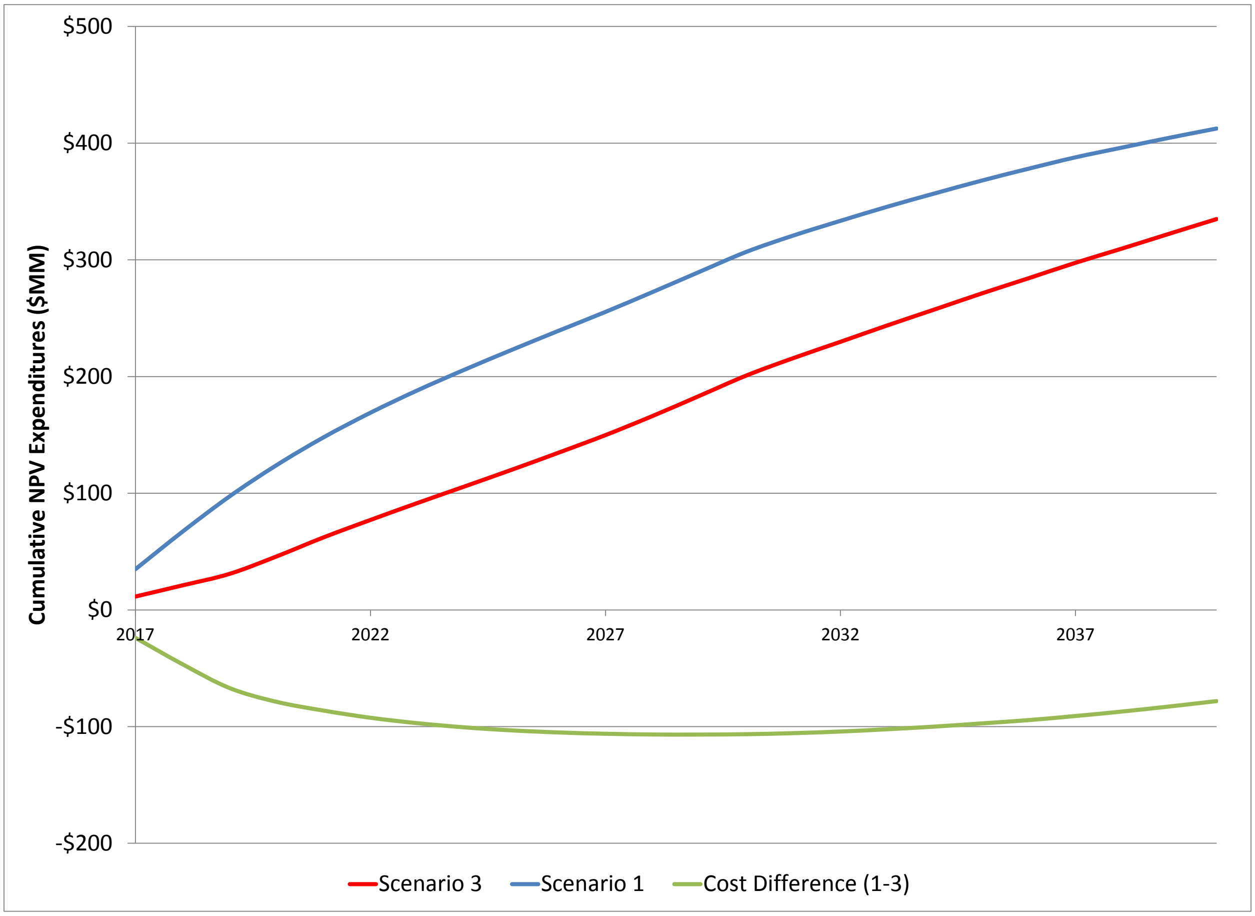

Figure 6-6 NPV Comparison of Select Inputs, Scenario 1 versus Scenario 3

As Figure 6-6 shows, the savings to SFPUC in Scenario 3 relative to Scenario 1 quickly reaches $100 million because of the deferral of the capital investments in the MPH. It should be noted that because of how the capital costs are modeled in this analysis (the EAA method, which spreads out and normalizes capital expenditures), this does not reflect when the actual costs will be incurred by the SFPUC. The EAA method and the IRP process are meant to identify differences between cases over a long planning period and are not intended to replace the biannual budget and investment cycle.

Following the initial benefits captured by SFPUC, the economic advantage of Scenario 3 continues to grow as the impact from selling high cost generation from MPH in the market is removed, with relatively lower cost market power purchased as needed to fill any load requirements. This advantage starts to decline in later years as market prices rise. ***It should be noted, however, that to compare the true value for any SFPUC sales or purchases from the market against generation options, the total costs, including all overheads, need to be included.*** These costs are not included as part of this analysis so as to best reflect just the cost of generation against each other for planning purposes; as part of the capital investment process, how overhead costs would be allocated to future generation options (and market purchases) should be taken into account.

From the analysis performed in the base cases, the following general conclusions can be made:

- ***Current SFPUC load and market prices make Scenario 3 the most economically attractive of the three scenarios examined****. SFPUC's supply and demand over the forecast period is well balanced in Scenario 3; Scenarios 1 and 2 lead to a considerable amount of market sales at pricing that is projected to be unattractive relative to the cost of generation throughout the vast majority of the analysis period.*
- ***Near-term MPH investments are high risk because the benefit is at the end of the analysis period*** *(2037 and later), and predicated on large increases to market prices above today's levels. Significant changes to the load, market price forecast, or investment costs would need to occur to provide sufficient economic justification for new capital investments at MPH.*
- ***Both HPH and KPH have low cost generation relative to the market price forecasts****. Investment should be made as necessary to keep generation levels from the powerhouses as high as possible, since sales into the market from these units are likely to be economically attractive. This is one reason why Scenario 1 appears more economically attractive than Scenario 2, since Scenario 2 defers maintenance on pumps needed to maximize output at HPH.*

To more fully understand the value of each scenario to the SFPUC, sensitivity and qualitative analyses were performed. The results of these analyses are discussed in the next two sections.

6.2 SENSITIVITY ANALYSIS

A number of assumptions were made as part of the IRP modeling to forecast the economic value of each scenario. To test the impact of changes in these assumptions, key sensitivity areas were identified in consultation with SFPUC staff. Sensitivity analysis was performed only on Scenarios 1 and 3, since Scenario 2 was found to be uneconomical when compared to the other two. Detail on the main sensitivity cases are outlined below:

- ***Increased Load Growth:*** *The high growth case outlined in Section 4.6 was used. Results from this analysis represent a bookend, with conclusions useful for the medium growth case as well. Generation options to meet load growth for Scenario 3, in addition to just market purchases, were also explored.*
- ***Market Power Price Changes:*** *Both the high and low market price cases were explored to provide a projection for how cases with high and low levels of market power sales and purchases would be affected.*
- ***Addition of Renewable Energy, Scenario 3:*** *The economic impact of adding 50 MW of solar, wind, or geothermal generation to the SFPUC resource mix in Scenario 3 was explored. Only Scenario 3 was chosen for this analysis, because of the need for increased generation during certain times of the year since Scenario 1 typically had excess generation. 50 MW was chosen to balance supply and demand in Scenario 3 but should not be considered an "optimal" amount of new capacity additions.*

- ***Meterological Uncertainty, 2025:*** *Market purchases and sales during one year of the analysis period were quantified to assess how they might change during wet and dry rainfall seasons relative to the average assumed in the base case scenarios.*

The results of the analysis for these sensitivity cases can be seen in the following subsections.

6.2.1 Increased Load Growth

As noted in Section 4.6, the under the high load case, load growth for the SFPUC accelerates at a greater rate than that projected in the base case analysis because of increases in the addition of load, new city tenants, and areas of redevelopment. In the high load case, 150 MW of new load would be added to the current system load by 2030, leading to an aggressive growth rate in the next 13 years. After 2030, load growth returns to the levels projected in the base case scenarios of 0.5 percent per year. How the SFPUC hydroelectric assets will be dispatched to meet these higher load projections, along with average yearly market purchase needs for Scenarios 1 and 3, is shown on **Figures 6-7 and 6-8**.

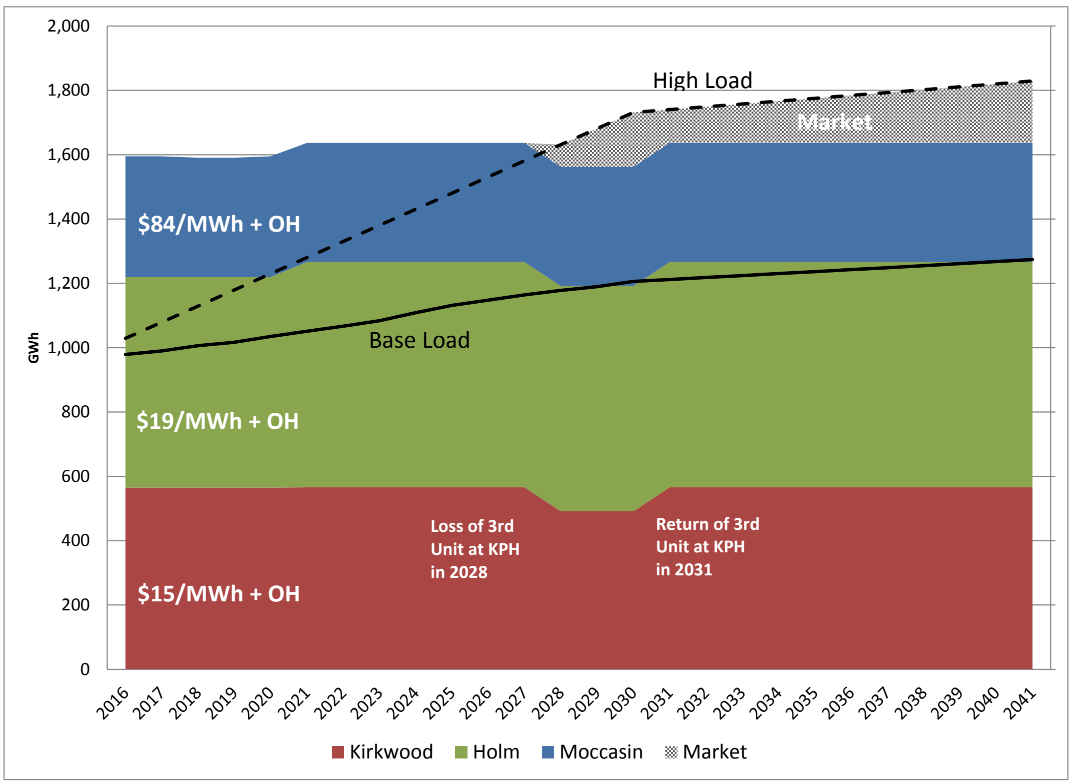

Figure 6-7 Scenario 1 Dispatch, High Load

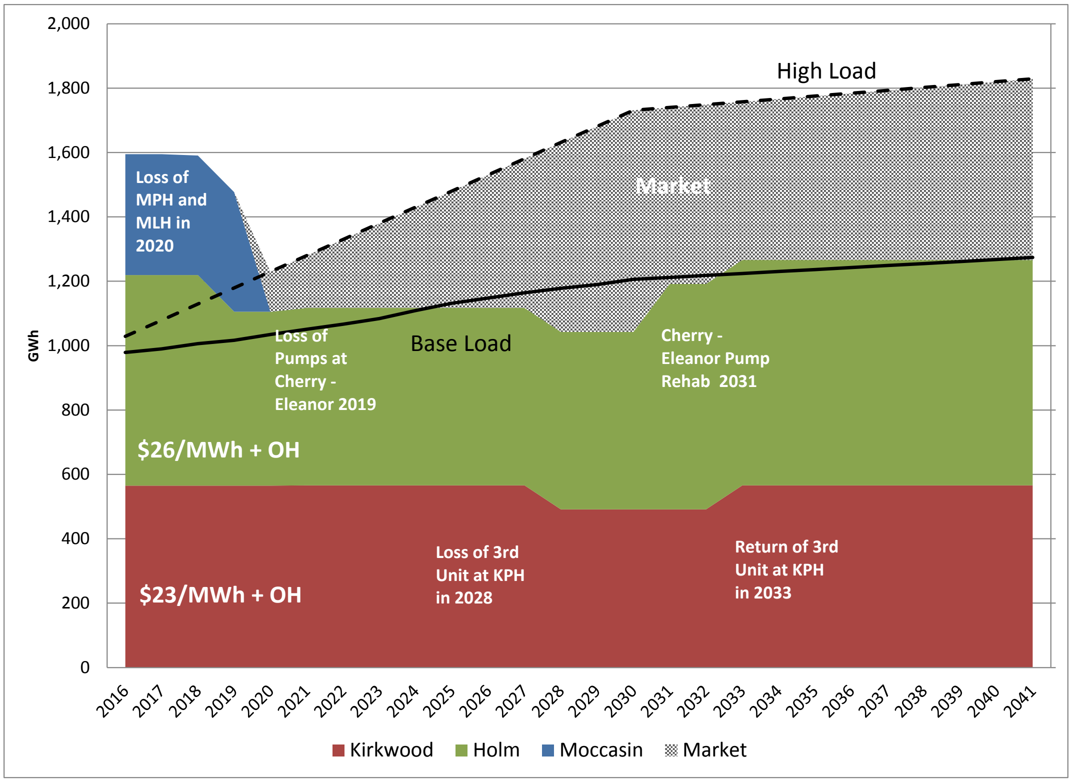

Figure 6-8 Scenario 3 Dispatch, High Load

As the figures show, the high load growth has a significant impact on the supply and demand balance for SFPUC. In Scenario 1, the excess capacity available from MPH is used up quickly, becoming a net importer of power at about halfway through the analysis period (2030). Scenario 3 quickly becomes short, requring significant purchases of market power, reaching roughly 500 GWh in 2041.

To provide a comparison of the resource options available to SFPUC if a large amount of load growth did occur, a third option was added to this sensitivity. This option added 50 MW of wind to the dispatch stack in Scenario 3. The intent of this case was to analyze another option for how SFPUC could meet future load growth while still meeting environmental and policy goals.

The amount of net market purchases or sales and NPV of each of the three sensitivity cases are shown in **Table 6-4**. The NPVs are much higher than the base case scenarios because of increased market purchases, greater RA needs, and higher CAISO T&D charges.

Table 6-4 Net Sales and NPV, High Load Sensitivity Cases

	SCENARIO 1 HIGH LOAD	SCENARIO 3 HIGH LOAD	SCENARIO 3 HIGH LOAD WITH WIND
Net Sales (GWh)	+2,119	-7,363	-4,501
NPV ($MM)	1,587	1,618	1,490 (lowest)

When only Scenarios 1 and 3 are compared without additional resources, Scenario 1 becomes slightly more economically attractive. In Scenario 3, SFPUC purchases a large amount of market power, which is less expensive than MPH power to fill demand for much of the analysis period, but this condition changes in the later years of the analysis, given the assumed significant increases to market power prices over time. In addition, Scenario 3, without the early Cherry and Eleanor pump maintenance work, leads to a case where net generation falls below 67 percent of the load in 2029 and 2030, potentially violating the alternative RPS compliance terms outlined in Section 4.7.

If SFPUC were to face a significant net short position (such as Scenario 3 under a high load case), a range of generation options should be considered so that exposure to market power prices could be reduced. Adding 50 MW of wind power to Scenario 3 significantly reduces the net short position and is more economically attractive than Scenario 1. It should be noted that 50 MW was added to be consistent with the renewable energy sensitivity case outlined later in this section; this figure should not be considered an optimal amount of new resource additions if the future SFPUC load was in fact projected to be higher than the base case. As a better understanding of load growth is developed in the future, additional generation options should be considered if confidence grows that SFPUC generation will become significantly short in meeting load. Fully optimizing this addition of renewable energy options to meet higher load may increase the economic benefits to SFPUC beyond the results of the sensitivity analyses presented in this IRP.

As mentioned in the discussion in Working Group 5, a high DER case was developed which would decrease SFPUC load below what was defined in the Base Case. Quantitative analysis of this case was not performed, for it is clear that a decrease in load would only improve the economics of Scenario 3 over Scenario 1. If load projections do begin to fall behind projections made in this IRP, that would provide further support for delaying investment in any new generation sources.

6.2.2 Market Power Price Uncertainty

One of the largest uncertainties that will impact the economics of many of the proposed scenarios is the market power price. Currently, SFPUC is selling a large amount of power into the market, which is also reflected in base case Scenarios 1 and 2. While the base case runs found that selling this amount of power into the market was uneconomical when compared to working toward a more balanced power supply and demand position, this may not be the case if the market power price were to change significantly.

To test the impacts of different market power prices, a new set of hourly prices for the entire analysis period was entered into the PLEXOS model for Scenarios 1 and 3. Both high power and low power price cases were analyzed, reflecting the range of potential costs projected by Black & Veatch. A depiction of the market price range explored throughout the analysis period relative to the generation cost for the three powerhouses can be seen on **Figure 6-9**. *Note that the cost of generation for each powerhouse does not include overhead.*

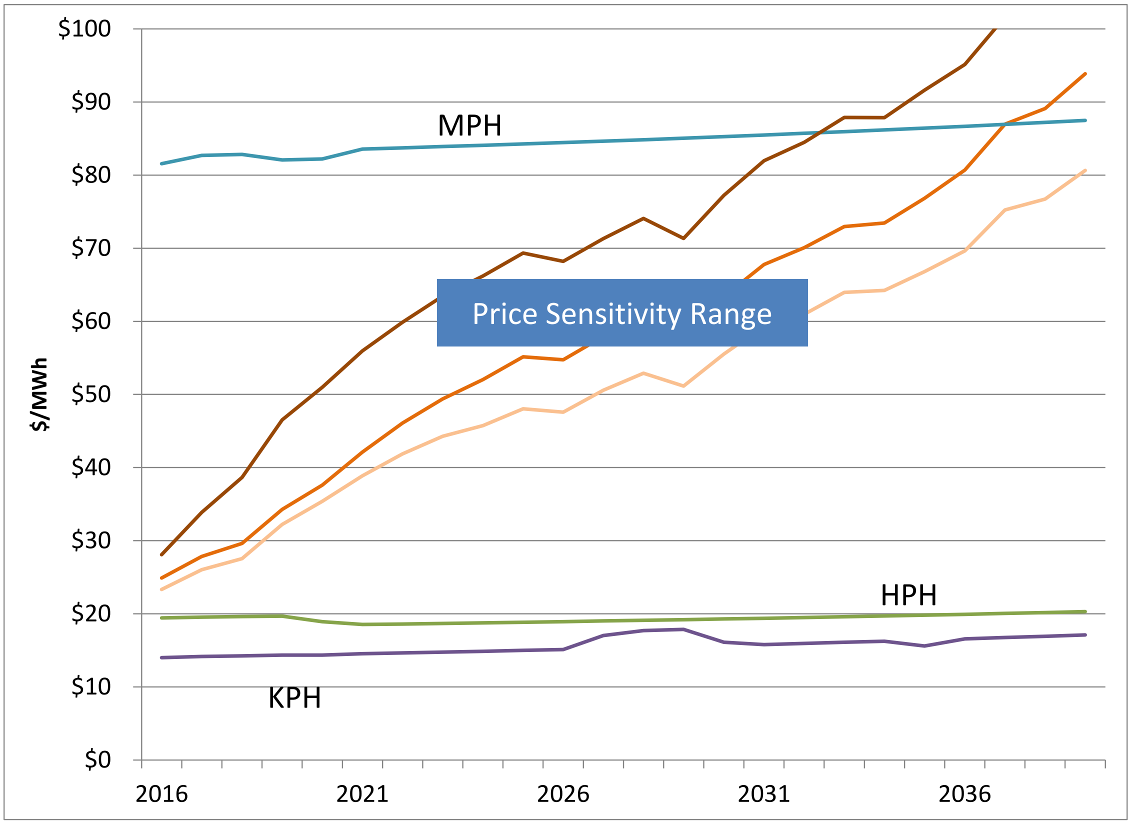

Figure 6-9 Market Price Sensitivity Range versus Hetch Hetchy Generation Costs Without Overhead

The NPV for Scenarios 1 and 3 under each of the three market power price cases are shown in **Table 6-5**.

Table 6-5 NPV of Scenario 1 and 3 Power Price Sensitivities

NPV ($MM)	SCENARIO 1	SCENARIO 3	LOWEST COST
High Power Price	990	973	Scenario 3 ($23MM)
Base Case	1,068	990	Scenario 3 ($78MM)
Low Power Price	1,103	993	Scenario 3 ($110MM)

From the results of this analysis, the following key conclusions can be drawn:

- ***Balancing Supply and Demand Limits Exposure to Market Volatility:*** *The NPV results varied little for each of the three price assumptions used for Scenario 3. This is because Scenario 3 power generation and demand is well balanced, which limits the amount of market purchases or sales required. This balance will shield SFPUC from market price volatility and risk.*
- ***Scenario 1 Remains Uneconomical Even With High Power Prices****: While the difference in NPV does shrink between Scenarios 1 and 3 in the high power assumption, Scenario 3 remains*

more economically attractive. Thus, even if market power prices were to rise to a level considered aggressive given current market conditions, SFPUC would still be better suited to limit market power exports from MPH.

- ***Potential for Low Power Pricing Provides Further Support for Scenario 3**: The NPV gap widens if market power prices are lower than projected in the base case. Regardless of the market power price explored, Scenario 3 remains more economically attractive.*

6.2.3 Renewable Energy Additions, Scenario 3

The base case Scenario 3 showed some net short periods during the analysis if the Cherry and Eleanor pumps at HPH were to go out of service in 2019. The value to SFPUC of putting additional renewable energy generation into the SFPUC generation mix was examined to determine whether this option might be economically attractive for filling this net short and whether the cost and generation profile would be attractive relative to market purchases.

The addition of 50 MW of wind, solar, and geothermal was tested by adding their cost and performance profiles separately into PLEXOS, assuming a startup in 2020. The assumptions for performance of each resource are outlined in Section 4.3.2. A graphical example the dispatch order in Scenario 3 with the addition of solar is shown on **Figure 6-10**.

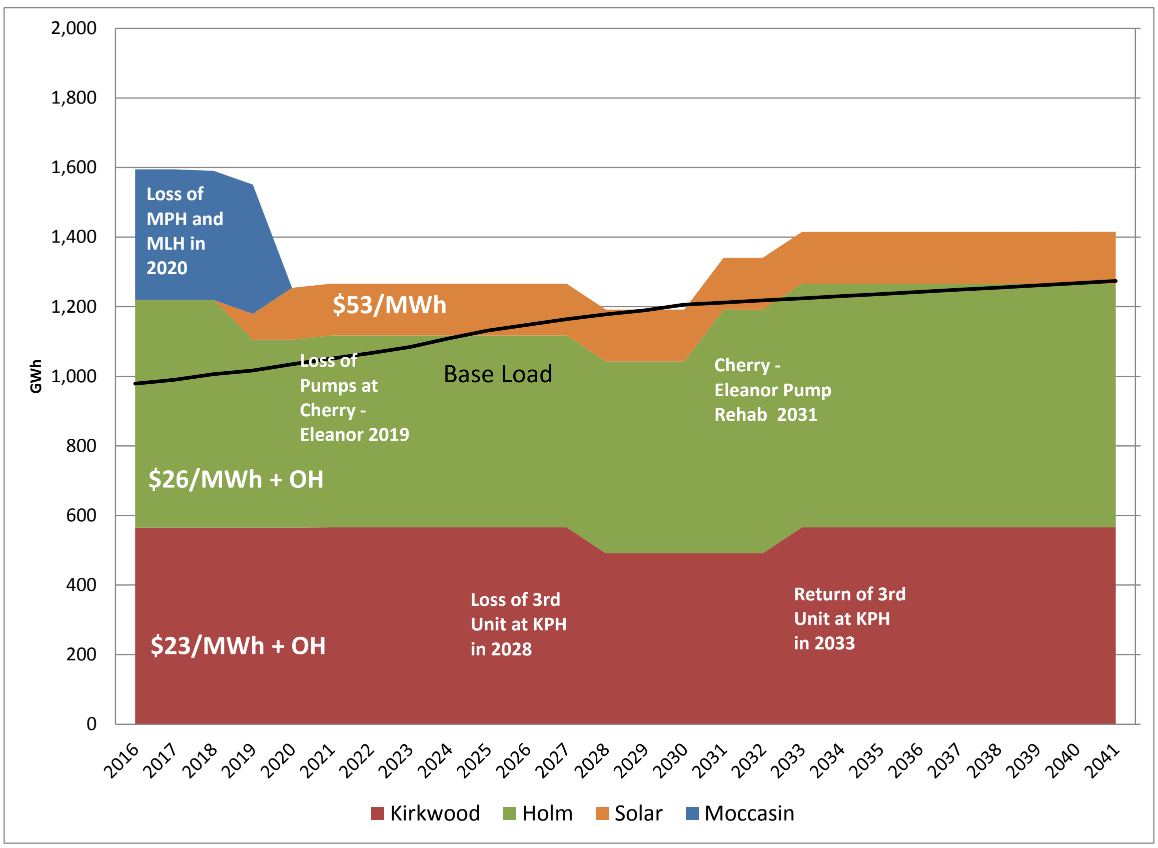

Figure 6-10 Scenario 3 Dispatch with Solar

Figure 6-11 provides context for the busbar generation cost of each of the renewable energy resources tested in the sensitivity analysis relative to market price assumptions and the SFPUC hydroelectric units. For each of the renewable resources, it is assumed that SFPUC either signs a long-term PPA with a third party at a fixed price or that SFPUC builds and operates the asset themselves and levelizes the price over the life of the asset. From past work performed by Black & Veatch for SFPUC, it was determined that the levelized generation cost of either approach, assuming no tax credits for third-party development, would be roughly the same. ***While the prices assumed for solar and wind are higher than those currently being offered in the market today, the price assumed reflects the assumption that a project developed for SFPUC by a third party would be done after the expiration of any federal production cost or investment tax credits.***

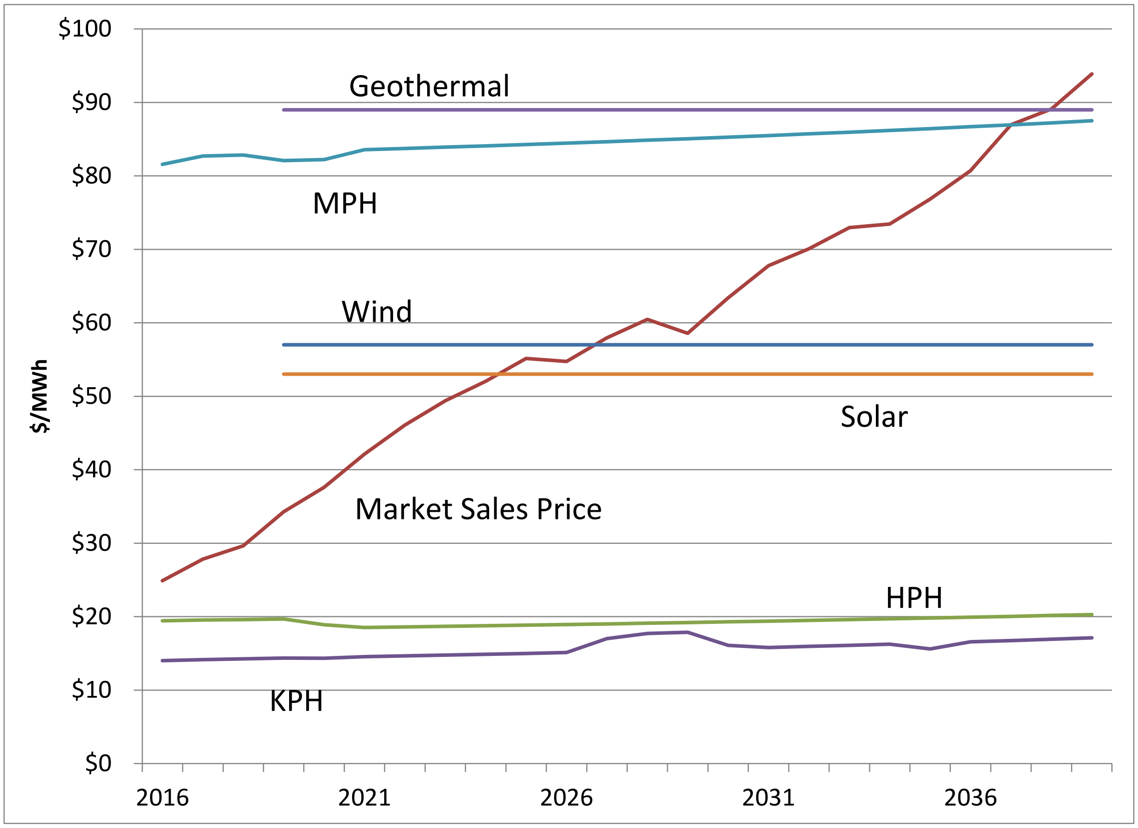

Figure 6-11 Hetch Hetchy Unit Cost of Generation versus Market Price and Renewables

When the addition of renewables was modeled in PLEXOS, the way the model bought and sold power in the market was different than in the base case scenarios, as outlined in Section 5.2, This assumed that SFPUC participates in the real time energy trading markets, because this becomes critical when serving load using intermittent renewables such as wind and solar. The impact of just adding real time energy trading to the hydroelectric unit dispatch without any additional generation capacity was also run in PLEXOS to determine how much of the results were driven by the addition of real time trading operations only.

The NPV of the three renewables cases and the real time trading case without new capacity additions can be seen in **Table 6-6**. It should be noted that the NPV of the case without real time trading case is different than that of the base case Scenario 3 since it includes deferral of the Cherry and Eleanor pump maintenance.

Table 6-6 NPV of Renewable Energy Sensitivity Analysis

	SCENARIO 3 NO REAL TIME TRADING	SCENARIO 3 WITH REAL TIME TRADING	SOLAR	WIND	GEOTHERMAL
NPV ($MM)	1,048	1,005	1,006	990	1,114

The results shown in Table 6-5 indicate little benefit to adding new renewable energy generation to the SFPUC system and that the majority of the benefit identified through the model is from the hourly dispatch optimization. Just optimizing dispatch without any new generation capacity produces an NPV benefit of $43 million. Adding additional solar generation capacity produces no benefit over just optimization without new capacity; 50 MW of wind generation produces a slight NPV benefit. Although new solar capacity is less expensive on a levelized cost basis than wind, the generation profile of wind is more favorable given SFPUC's hydroelectric generation profile and market price projections. Geothermal power generation is uneconomical compared to solar or wind given its higher generation cost and the lack of need for baseload generation on the SFPUC system.

One item that is not included in the economic analysis of the real time trading and renewable energy cases is the cost to implement hourly dispatch. Performing hourly dispatch would require additions in staffing, implementation of new software and market interaction models, and changes in powerhouse operations. The cost of these steps would need to be considered to determine whether the projected savings would justify the expense.

6.2.4 Meteorological Uncertainty

In the base case, each of the powerhouses was modeled with "average" yearly generation for planning purposes. While there will certainly be yearly output variants, using averages is reasonable for planning purposes when considering the impact on investment decisions over a long period of time.

To gather insight on how wet or dry hydroelectric generation years would impact the base case results, total generation from the hydroelectric units was estimated for one year (2025). For this single year, the analysis estimated the impact of wetter or drier weather on total hydroelectric generation. A new PLEXOS run was not necessary since not all years were being modeled (it is not practical to assume 25 years of drought or heavy precipitation), and in the no real time trading cases, the only impact this would have would be on the amount of net market sales or purchases.

The results for how net sales would be affected for 2025 in the base case Scenarios 1 and 3 can be seen in **Table 6-7**. Positive numbers are exports while negative numbers reflect net imports.

Table 6-7 Impact of Wet and Dry Hydro Years on Net Sales

2025 NET SALES (GWH)	SCENARIO 1	SCENARIO 3
Wet Year	693	118
Normal Year	527	6
Dry Year	412	(-72)

As would be expected, wet years lead to significantly greater exports (100 to 170 GWh depending on the case), while dry years reduce the level of exports and lead to Scenario 3 becoming a net importer of power. No general conclusions can be drawn for the economic impact of wet or dry years through this sensitivity analysis alone; cost-effectiveness of market sales and purchases depends on the marginal cost of generation, as well as the market price for power. In Scenario 1, the marginal cost of generation is $85/MWh (plus overhead costs) from MPH, while in Scenario 3, the marginal cost is $26/MWh (plus overhead costs) from HPH. ***Since MPH generation is more expensive than market power (losses of $32/MWh plus overhead), dry years would be economically better since expensive market sales would be reduced.*** However, the opposite is true for Scenario 3 where excess sales from generation at HPH is economically attractive (revenue of $20/MWh minus overhead costs), leading to a cost benefit (or at worst breakeven) during wet years.

6.3 QUALITATIVE FACTORS

Besides the economic analysis outlined above, a number of qualitative factors should be considered when evaluating the different resource options available. These factors largely represent risks due to changes in assumptions or market conditions, utility preferences, and ability to respond to unforeseen operational situations.

Table 6-8 shows the major qualitative factors evaluated as part of the IRP, and how Scenarios 1 and 3 compare under each. Each scenario is scored on a metric of green (little to no concern), yellow (caution is advised), or red (high risk or concern of unfavorable outcomes). Factors are listed in the order of greatest to least risk relative to Scenario 1. The following factors were evaluated:

- *Capital Investment Risk*
- *Market Exposure Risk*
- *Supply Diversity*
- *Load and Operational Flexibility*
- *Impact Under Variable Weather Conditions*
- *Environmental Performance*
- *System Reliability*
- *Ownership*

These factors were deemed to be the ones that could impact the system performance the most and have the greatest potential for change relative to the base case. Other items, such as changes to currently enacted policy or new policies that could materially impact the future investment or *operational requirements for SFPUC, were deemed to be unlikely and, therefore, were not included in **Table 6-8**.*

Table 6-8 Scenario 1 and 3 Qualitative Factor Rankings

FACTOR	DESCRIPTION	SCENARIO 1	SCENARIO 3
Capital Investment Risk	Risk of long-term uneconomical or stranded assets	High risk of carrying forward significant long-term debt on uneconomical MPH asset	Flexibility to invest in only the most economic assets while adapting to market conditions
Market Exposure Risk	Financial uncertainty due to high level of variability in market prices	Considerable exposure to market prices due to oversupply; uneconomical regardless of forecasted changes	Balanced supply and demand; minimal exposure
Supply Diversity	Diversity in generation resources	Remains heavily invested in hydro generation	Flexibility to choose greater diversity to meet future load obligations economically
Technology Leadership/ RPS Content	Deployment and support of advanced generation technologies for power generation	Large hydro generation only	Greater consideration of new renewable resources to meet load
Load and Operational Flexibility	Ability to adapt to major changes in system load or performance requirements	Limited flexibility because of high level of generation commitments exceeding load and water first requirements	Flexible as needs change; could purchase new assets if needed or economically sell excess
Impact of Variable Weather Conditions	Performance under different weather conditions	Greater financial losses during wet years because of more MPH sales	Higher market exposure during dry years, but impact is limited
Environmental Performance	Level of criteria pollutants and greenhouse gas (GHG) emissions	No fossil assets and few market purchases	No fossil assets; flexibility to choose future generation sources
Service Redundancy	Ability to meet service performance obligations	Excess generation capacity available to meet needs if system issues arise	Balanced supply and demand; would be more dependent on market in case of generation issues

FACTOR	DESCRIPTION	SCENARIO 1	SCENARIO 3
Ownership/ Independence	Dependence on third parties to meet load obligations	No new third-party obligations	Potential third-party obligations if future load rises; could also meet through SFPUC ownership
Intrinsic Value to CCSF	Maintaining assets of historical importance	Preservation of Hetch Hetchy legacy assets	Deferral of investment in a historically significant asset (Moccasin)

The items of greatest difference between Scenarios 1 and 3 that are more negative for Scenario 1 are capital investment risk and market exposure risk. SFPUC is facing a large capital investment in the near future for assets associated with the MPH. If the decision is made for Power Enterprise to fund a significant portion of this investment, it will be committing to long-term payments for operations of MPH. The economic value to Power Enterprise of MPH under a range of future scenarios is likely to be low relative other options; this range of possible outcomes must be taken into account when evaluating the investment decision and timing. Market exposure represents another higher risk to Scenario 1 compared to Scenario 3 since generation far exceeds demand in Scenario 1. Market prices are not expected to make the marginal cost of generation economical in Scenario 1, and this could be even more pronounced if prices remain lower than projected in the base case. Even if market prices rise beyond the base case, the overall economic value does not rise beyond Scenario 3.

Scenario 1 also has less potential supply diversity and less technology leadership/use of RPS eligible resources (there is no projected need for new resources even under a high load scenario in Scenario 1, while non-hydro resources are projected to be the preferred option to meet high load demands under Scenario 3) and less flexibility to respond to changes in load or operational needs. Committing to long-term operations of all three Powerhouses limits the options available to SFPUC if load were to change appreciably up or down, or if electric market rules change to require greater operational flexibility. Also, Scenario 1 has greater downside due to the impact of variable weather conditions, since financial losses could be much greater during wet years compared to the worst weather conditions modeled for Scenario 3.

A factor deemed to have similar rankings between the scenarios is environmental performance. Environmental performance of Power Enterprise is likely to be similar under either case, since no fossil resources are used in either, and REC needs are projected to be limited.

Three factors were more favorable for Scenario 1 relative to Scenario 3: service redundancy, ownership, and intrinsic value to CCSF. Scenario 1's large excess of generation provides a cushion to be able to meet system loads in case of operational problems at any of the powerhouses. In addition, SFPUC maintains ownership over all generation assets in Scenario 1, while Scenario 3 may rely on third-party generation to meet future load obligations economically. However, under Scenario 3 new renewable energy projects such as solar or wind could be developed and owned by SFPUC if desired, which would help to mitigate some of these shortcomings. Finally, deferring investment into Moccasin Powerhouse in Scenario 3 would impact the operation of an historical asset that has been in operation since 1925.

6.4 SUMMARY OF KEY FINDINGS

SFPUC's 2017 IRP examines several options for future resource needs and system uncertainties within the power supply portfolio, including deferral of MPH investments, renewable resource additions, and the impacts of changes in market pricing. The base case analysis shows that pursing a balanced supply and demand portfolio and deferring investment in MPH provides an NPV advantage of nearly $80 million over the 25 year analysis period, along with lowering capital investment and market exposure risks when compared against attempting to maintain current generation levels through additional investments in MPH. This option also provides greater flexibility for adapting to future load changes at low cost, either through adding new resources, or selling future excess into the market economically.

Primary findings from the analysis include the following:

- ***Load growth would need to be significant and more certain to justify additional SFPUC generation beyond what is needed for load.*** *Under the high-load sensitivity, it was determined that other resource options may be more economical than near-term investment in MPH-related equipment. Thus, delaying investment in new generation options until higher load growth is more certain appears to be justified.*
- ***Market pricing would need to rise significantly to support investment in high cost assets.*** *Current marginal generation costs (at MPH) are already far above the market value for power. As major capital intensive maintenance projects are implemented in future years, these marginal generation costs will continue to rise even further. Even under the high market price sensitivity case explored, marginal generation costs in Scenario 1 remained above the market price for much of the analysis period. Furthermore, future hourly and seasonal market price projections will continue to be unfavorable for SFPUC's primary generation assets, as prices tend to be depressed during the high hydroelectric generation time periods.*
- ***HPH and KPH are roughly breakeven with market price once overhead costs are added in the initial years of the analysis, becoming economic in all cases relative to the overall energy market .*** *Because of the value of these assets to either meet load or sell into the market, performing whatever maintenance is needed to keep them running at full capacity (such as the Cherry and Eleanor pump work) is economically justified over the long-term. Not performing this work is the reason why Scenario 2 looked unattractive relative to both Scenarios 1 and 3. In addition, maximizing output at these units is necessary to prevent any alternative RPS compliance violations in the Scenario 3 high load case when no additional resources are added.*
- ***Balancing load and generation insulates SFPUC from any volatility in market power pricing.*** *This was shown when the Scenario 3 NPV varied little regardless of the market power price assumed.*

Secondary findings are summarized below:

- *Implementing real time optimization could have economic benefits (roughly $40 million over 25 years on an NPV basis). SFPUC would need to take into account the cost and operations impact of adding real time optimization to the system to determine whether this level of benefit justifies the change.*

- *Although wind PPAs may be slightly more expensive than solar in the future, the inclusion of wind adds resource diversity and is a better fit to the load profile, which could help SFPUC if load were to rise. As market conditions change, SFPUC should continue to evaluate alternative resource procurement opportunities that may arise with an eye on overall portfolio resilience and flexibility.*

Finally, it is understood that Power Enterprise decisions must take into account the overall goals and constraints of the broader SFPUC organization. This IRP utilizes an approach and best practices consistent with what is done at other electric utilities but does not include the impact of any of the scenarios on Water operations, qualitative factors related to any non-Power Enterprise issues, or the overall economics of the SFPUC as a whole. A broader organizational approach should use the results of this IRP document as inputs to that type of decision making.

Appendix A. Working Group Details

A.1 WORKING GROUP MEMBERS AND MEETINGS

Working Group	Members	Meetings
1-Cost Allocation	Charles Perl Crispin Hollings Margaret Hannaford Cheryl Sperry Erin Franks Lori Mitchell Karina Leung Manuel Ramirez Cheryl Taylor Rocco Pallante Adam Taylor Ann Tu-Anh Bui (Black & Veatch Lead)	The full WG1 met twice in June, 2016 and met a number of times as a smaller group to finalize the main assumptions and review the cost allocation model results.
2-Generation	Margaret Hannaford Adam Mazurkiewicz Rocco Pallante Brent Horger Tracy Cael Herman Hemati Ellen Levin Lori Mitchell Meg Meal Manuel Ramirez Karina Leung Erin Franks Adam Taylor Benson Joe (Black & Veatch Lead)	The full WG2 met twice in June, 2016. Following the full WG meetings, collaborations continued through smaller group meetings and conversations until assumptions were finalized.
3-Transmission	Margaret Hannaford Rocco Pallante Manuel Ramirez Lori Mitchell Karina Leung Jiayo Chiang Adam Taylor Benson Joe (Black & Veatch Lead)	The full WG2 met twice in June, 2016. Following the full WG meetings, collaborations continued through smaller group meetings and conversations until assumptions were finalized.

4-Market Pricing	Lori Mitchell Jiayo Chiang Margaret Hannaford Meg Meal Herman Hemati Randall Smith Jim Andrews Jamie Seidel Adam Taylor Karina Leung Benson Joe (Black & Veatch Lead)	The full WG4 met once in June, 2016. Following the full WG meeting, collaborations continued through smaller group meetings and conversations until assumptions were finalized.
5-Electric Demand	Herman Hemati David Robinett Meg Meal Pam Husing Sam Larano Cheryl Taylor Karina Leung Grace Tang Ralph Leong Jonathan Cherry Lori Mitchell Adam Taylor Benson Joe (Black & Veatch Lead)	The full WG2 met twice in June, 2016. Following the full WG meetings, collaborations continued through smaller group meetings and conversations until assumptions were finalized.
6-Policy	Jim Hendry Margaret Hannaford Cheryl Taylor Adam Taylor Meg Meal Charles Perl Erin Franks Karina Leung Lori Mitchell Cheryl Sperry Nancy Abbott Manuel Ramirez Scott Olson (Black & Veatch Lead)	The full WG2 met once in June, 2016. Major policy assumptions were discussed during this meeting.

Appendix B. Cost Allocation Model Details

B.1 FINANCIAL ASSUMPTIONS

A key element when developing financial assumptions for use in the net present value (NPV) analyses is to make sure that the assumptions used are consistent with those used by the SFPUC in other business case evaluations. To that end, for the first 10 years of the evaluation period, financial assumptions follow those used in SFPUC's 10 Year Financial Plan, except as noted in the following sections. For the remaining years of the analysis period, SFPUC's Finance Department provided guidance for the process. Table B-1 summarizes key financial assumptions used in the cost allocation model (CAM).

Table B-1 Financial Assumptions

ITEM	ASSUMPTION
Level of Cash Financing	The Finance Department's goal is to cash-finance approximately two-thirds of any capital project. Exceptions to this guideline include the following: • In the 10 Year Financial Plan, the Mountain Tunnel project is fully debt financed. • With the exception of the debt issued for Mountain Tunnel, all other projects are cash-financed. • For Years 11 through 25, when using the 2/3:1/3 financing guideline, if the debt amount issued is less than $10 million, the entire project is cash-financed. • Additionally, for any large capital projects over $200 million (such as the replacement of Lines 3 and 4; the Moccasin Powerhouse Rotor rewind, and the reservoir projects), up to 96 percent of the project may use debt financing.
Debt Financing Terms	Interest Rate = 5% Tenure = 30 years Capitalized Interest = 2 years Debt Service Reserve Requirement = Yes (for Years 11 through 25)
Operating Fund Target	15% of Operations and Maintenance (O&M) Expense
NPV Discount Rate	5%

B.2 YEARS 11 THROUGH 25 PROJECTIONS

The starting point for future year projections regarding O&M expenses, revenues, and customer growth is the 10 Year Financial Plan. After discussions with the Working Group 1, inputs from infrastructure, and data from the other working groups regarding the basis for their future year projections, Working Group 1 agreed upon the escalation rates summarized in Table B-2 for use in the CAM. Black & Veatch understands that the escalation rates used in SFPUC's 10 Year Financial Plan also contain an allowance for growth; in other words, they do not represent pure inflation factors. The same approach has been adopted for escalating future year projections.

Table B-2 Future Year Escalation Factors

ITEM	ESCALATION FACTOR
Salaries and Benefits	3%
Contract Services	3%
Materials and Supplies	3%
Utilities	3%
Administrative	3%
Equipment	3%
Maintenance	3%
Consumer Price Index (CPI)	2.75%
Future Year Capital Investment Plan (CIP) Escalation	3.5%
Future Year Customer Growth	2%
Future Year Revenue Growth	2%
Sunset Power Purchase Agreement (PPA) After Contract End	2.15%

B.3 ALLOCATION

B.3.1 Cost Centers

The first step in the cost allocation process is to identify the cost centers that generate the costs that the CAM is examining. The main cost centers selected are outlined below, with a graphical overview shown on Figure B-1:

- *Supply: This cost center is further delineated by the specific type of supply (Moccasin, Kirkwood, and Holm Powerhouses)*
- *Local renewables and supply*
- *Energy Efficiency projects for municipal customers*

- *Purchased supplies and other needs (this is a cost center defined in the CAM, but the actuals used in the IRP are based on PLEXOS model results and not CAM projections).*
- *Risk Mitigation*
- *California Independent System Operator (CAISO) Grid Charges*
- *Transmission: Unlike the 2016 Rate Study, the transmission cost center is further subdivided by line segment*
- *Distribution: This cost center consists of owned distribution interconnections, owned load interconnections, and Pacific Gas and Electric (PG&E) distribution.*
- *City Programs: This cost center supports citywide programs and includes owned streetlights, PG&E streetlight services, community benefits, and support to other departments.*
- *Other Shared Costs: Back-office costs are in this cost center, such as administrative, Hetch Hetchy Water Programs, Hetch Hetchy Power Programs, bureau/Countywide Cost Allocation Plan (COWCAP) costs, and billing and customer services.*

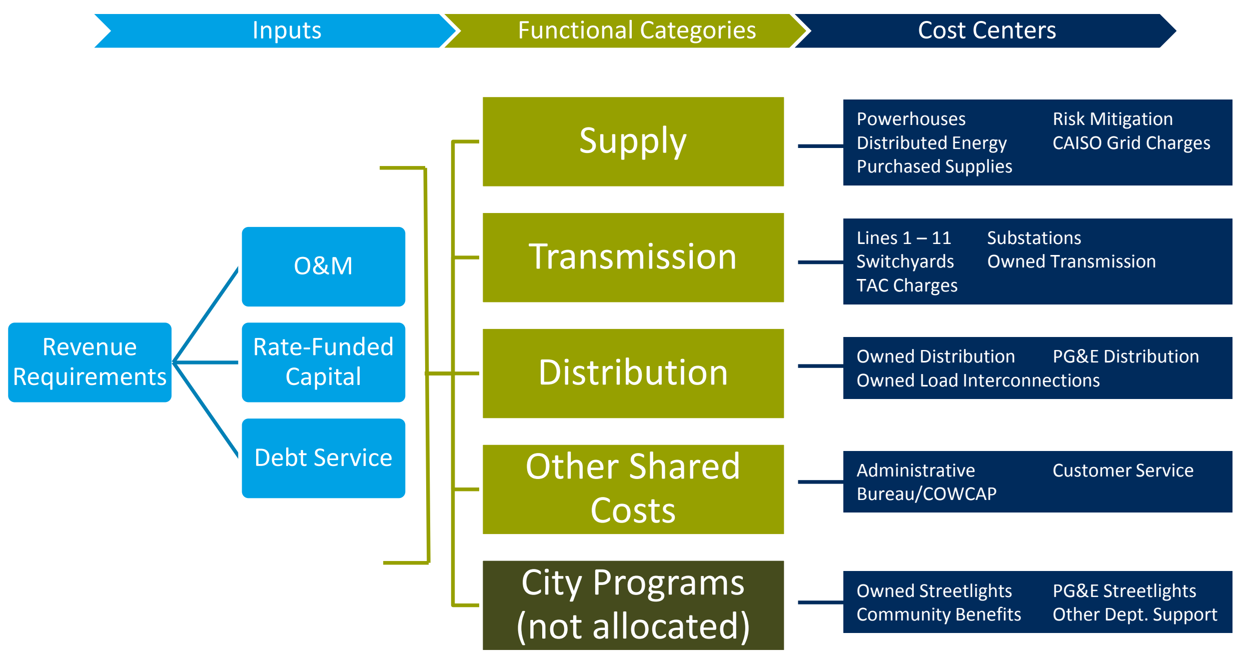

Figure B-1 CAM Allocation Cost Centers

B.3.2 Allocation Between Cost Centers

After Working Group 1 identified and agreed upon the cost centers, Black & Veatch moved to the next step in the allocation process, distributing the line item expenses to each cost center. The basis for allocation uses one of three techniques:

- *Direct Allocation: This allocation method occurs when there is a known relationship between the expense and the category. For example, costs of the Sunset PPA are directly allocated to the purchased supplies and other needs category since that is where those costs are budgeted.*
- *Percentage Allocation: With this method, a spreading of distribution across relevant categories serves as the basis for allocation. For the IRP, percentage allocations could be based on head count, power generated (in MWh), or a pre-determined and agreed upon split (such as 90/10 for streetlights). Allocations based on historical trend analysis also fall into this group.*
- *Sum-of-the-Above Allocation: This option is used when the cost being allocated is a function of other activities within the category. For example, administrative costs generally provide a service to everyone, so the allocation method may prorate the cost across all categories based on the proportionate cost incurred under general services.*

With respect to O&M expenses, Black & Veatch again followed the underlying assumptions contained in the approved 10 Year Financial Plan. As a starting point, the cost allocation model uses the approved fiscal year (FY) 16/17 and 17/18 budget numbers. For the Hetch Hetchy Water and Power (HHWP) system, Finance used the FY 15/16 budget as the basis for splitting O&M costs between Water and Power.

B.3.3 Allocation of Debt Service and Cash-Financed CIP

For existing debt service costs, Finance provided the bond statements that helped identify the intended use of bond proceeds to allow direct allocation to the appropriate cost centers. For proposed debt service costs and the cash-financed portion of capital projects, the allocation methodology follows the same process described below for the CIP.

B.3.4 Allocation of CIP Projects

Unlike O&M expenses, the allocation of CIP projects is a more labor-intensive process. Here, project details are examined so that the proper allocation of cost can take place. For example, while a project may be titled "Kirkwood Powerhouse," that does not mean that there is not a sizeable portion of the project that may be related to improvements to Lines 9, 10, or 11. HHWP resources staff reviewed the proposed CIP projects and provided detailed spreadsheets supporting the allocation of costs to the appropriate cost centers.

B.3.5 Overhead Costs

Overhead or shared costs (in SFPUC terminology) are those expenses incurred in the administration of the utility. The allocation of overhead costs (other shared costs) depends on (1) the purpose of the analysis and (2) the ability to apply the same approach to all alternatives. For the SFPUC IRP, the purpose of the project is to identify the least-cost portfolio. Thus, the other shared costs category is a "fixed" cost and not allocated to the supply or transmission assets. If the SFPUC was trying to determine what rate to charge its customers, full cost recovery would be appropriate, and the approach would be to allocate these overhead costs to the different cost categories/assets.

For the IRP, Working Group 1 identified two types of overhead costs: those related to supply activities (risk mitigation and CAISO grid charges) and shared overhead (primarily administrative charges). By agreement, allocation of supply-related overhead costs to local supply subcategories is based on used annual power generated. The local renewable and energy efficiency projects are not included in this re-allocation because these projects are local to the area and not part of the grid.

For shared overheads, the amount spent in each O&M budget category serves as the basis for re-allocation. As noted above, the "sum-of-the-above" approach takes the total shared cost for each budget category and allocates it to the cost centers based on the proportionate spend in each center within the budget category.

City program costs, although identified for the sake of completeness, are not re-allocated to the powerhouses or other sources of supply.

B.4 COST ALLOCATION SENSITIVITY ANALYSIS

The results of any analysis are only as good as the assumptions supporting the analysis. To test the sensitivity of the CAM, Working Group 1 directed Black & Veatch to examine the sensitivity of the results for changes in facility life and different discount rates.

Figure B-2 shows the impact of facility life on the equivalent annual annuity (EAA) calculation for Moccasin Powerhouse only, and a comparison to the average annual spend based on items entered into the CAM for the IRP analysis period. It shows that shorter EAA periods (30 years) spread out the cost over a shorter asset life, thereby raising the average cost. Conversely, spreading the costs out over the full life of all assets associated with Moccasin Powerhouse would lower the average annual cost. There is little impact on the results for the Kirkwood and Holm Powerhouses because most assets fall within the 40 year cap.

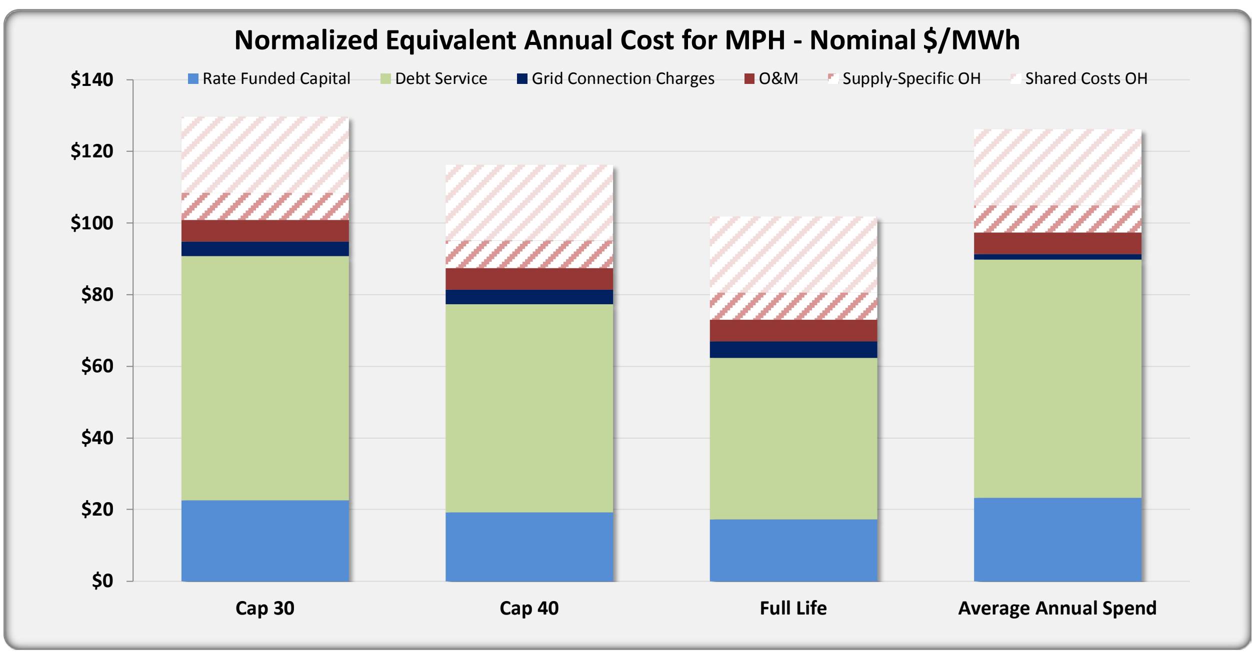

Figure B-2 Impact of Facility Life on EAA for Moccasin Powerhouse

The traditional NPV approach uses a weighted average cost of capital (WACC), which looks at the capital structure of the entity. With the high level of cash financing used for the CIP, using a WACC approach is reasonable. The difficulty lies in estimating the cost of equity. The traditional definition of the cost of equity is the risk-free earnings on cash plus a risk premium. Applying this approach in the current financial market and assuming a 0.5 percent risk premium, this leads to a 1.5 percent cost of equity. Plugging these values into the WACC formula and using a 5 percent cost of debt produces the following:

$$\text{WACC} = \underbrace{34\% \times 5\%}_{\textbf{Debt}} + \underbrace{66\% \times 1.5\%}_{\textbf{Cash}} = 2.69\% \text{ (round to 3\%)}$$

Figure B-3 illustrates the CAM model results for a 3 percent discount rate (WACC) and a 5 percent discount rate (used in all other business case evaluations) on the EAA for Moccasin Powerhouse. The sensitivity analysis shows that the lower the WACC (discount) rate, the more weight is given to near-term investments. Results shown are in $/MWh.

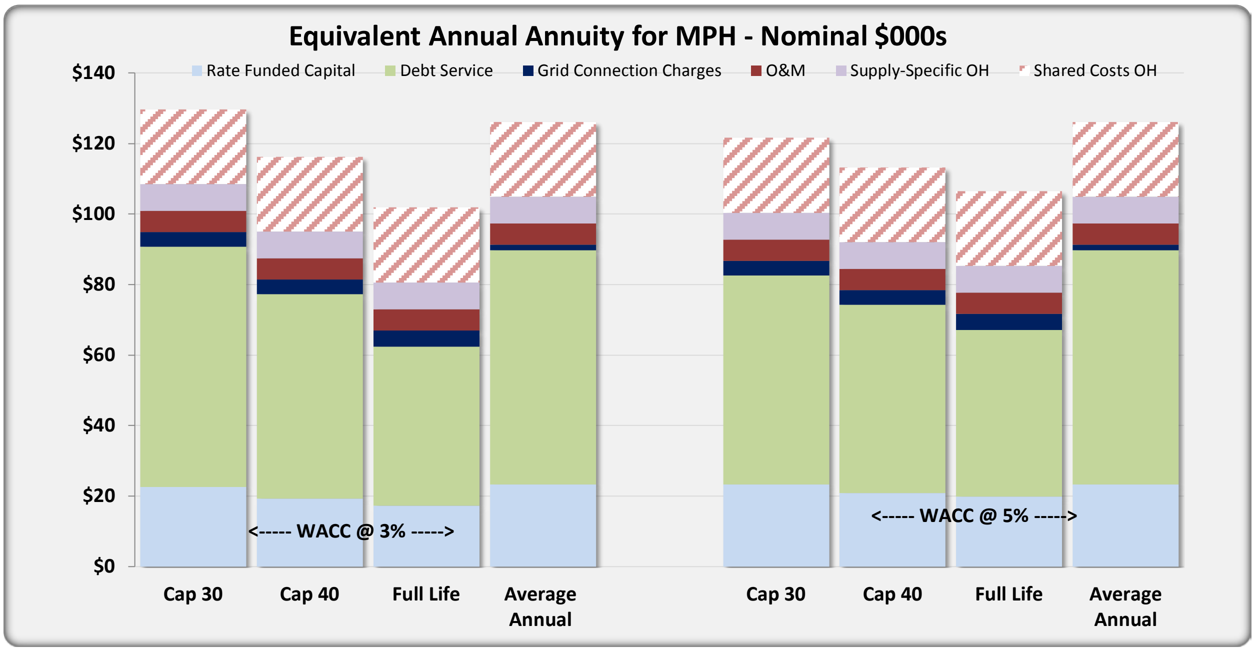

Figure B-3 $/MWh Impact of Different Discount Rates on Moccasin Powerhouse EAA