NewGen Strategies & Solutions

www.newgenstrategies.net

BB&A

Bell Burnett & Associates

SIEMENS

PHASE I REPORT

PUBLIC POWER FEASIBILITY STUDY

JULY 11, 2023

The City of SAN DIEGO

Prepared for:
City of San Diego

Table of Contents

List of Appendices

List of Tables

List of Figures

EXECUTIVE SUMMARY

The City of San Diego's (City) Strategic Plan under Mayor Todd Gloria is founded on the principles of customer service, community empowerment, equity and inclusion, and transparency. In line with the directive to be responsive to resident needs, the City is actively investigating options to expand public utility services to include electric delivery. This effort resulted in the development of the enclosed Phase I report for the Public Power Feasibility Study (Study). This Study is a multi-phased approach to evaluate the processes, costs, risks, and opportunities associated with municipalizing the energy infrastructure assets of San Diego Gas & Electric (SDG&E) within the City.

NewGen Strategies and Solutions, LLC (NewGen) partnered with Bell, Burnett & Associates (BB&A) and Siemens Power Technologies International (Siemens PTI or Siemens), collectively the NewGen Team, to provide a robust, multidisciplinary, and dedicated consulting resource to the City to support its needs for this Study and to create this Phase I report. The Sustainability and Mobility Department (Department) leads this effort on behalf of the City, as the Study is partially driven by the objectives of the City's Climate Action Plan (CAP). Further, this Department serves as the custodian of the City's transition to 100% renewable energy through San Diego Community Power (SDCP) and has administrative oversight of the current SDG&E franchise.

Study Scope

This Study is a multi-phased, multi-disciplinary review of selected issues, concerns, and processes that the City will need to address as it considers municipalizing the power delivery assets of SDG&E and forming a Municipal Energy Utility (MEU). The City's implementation of this Study is anticipated to occur as a series of coordinated and interconnected phases. This report and the recommendations included herein represent the results of Phase I of the Study. The specific elements of Phase I include the following:

- Develop Process Maps
- Review Public Power Entity Options
- Develop initial financial determinations regarding existing electric and gas systems in the City
- Develop initial financial and operational options and needs for a Public Power entity

Process Maps

The City requested the development of municipalization process maps for this report. The process maps lay out a series of analyses, decisions, and activities to be undertaken by the City over the course of its municipalization effort. The process maps are also supported by a series of "sub-process" maps, which provide detail into various elements critical for the City's municipalization effort. Each process map consists of two or more horizontal "swim lanes" which are assigned to an entity or entities, such as the City, and include the activities and the responsibilities of those entities within the lane. As identified in the Public Power Process map, Phase II activities focus on performing in-depth analysis and assessing community priorities and support, culminating with the development of a Municipalization Strategic Plan, anticipated to be completed by June 2025. The results of the Municipalization Strategic Plan will prompt a decision by the City to determine if moving forward with municipalization is warranted. If so, the next step in the process is a decision by the City to apply to the Local Agency Formation Commission (LAFCO) for regulatory approval to form a municipal utility (Phase III of the Study). However, if the City decides not to apply to the LAFCO, the municipalization process is terminated.

If the City decides to move forward with municipalization, it is anticipated that during Phase III it will enter into formal negotiations with SDG&E regarding the City's Municipalization Strategic Plan. If the City and SDG&E are unable to negotiate a successful agreement, the City may decide to move forward with the condemnation process (Phase IV). The result of the condemnation process is another decision point by the City to determine if the asset price is feasible to support development of a municipal utility, as well as potential further negotiations with SDG&E. If a feasible purchase price is determined, the City may choose to move forward with the development of its MEU.

Review Public Power Entity Options

This Phase I report also included a review of the various options for the structure, governance, and organization of a potential MEU. To support this evaluation, an organizational assessment of the current City operations was conducted by the NewGen Team. The focus of this organizational assessment was on the challenges that currently exist within the City relative to the potential establishment of an MEU. The result of the organizational assessment was the identification and evaluation of organizational options for a municipal entity within the City.

As part of the organizational assessment, various parties across several City departments were interviewed to gain insight into the operations of an electric utility in the current City environment. These interviews resulted in seven primary areas of concern for the creation of an MEU:

- Personnel Systems
- Procurement
- Knowledge of Management/Staff
- NERC
- IT Systems
- Centralized Systems
- Bandwidth

The assessment of the City organization as it exists today suggests that the gap between current capabilities and capacities and those needed to successfully operate a large MEU is extensive. The NewGen team notes that the City is aware of this gap and the challenges that it represents.

High-Level Financial Capacity Analysis

The High-level Financial Capacity Results illustrate that municipalization of the electric delivery assets within the City is financial feasibility on a preliminary basis. However, it is important to look at these estimated results on a cumulative and relative basis. The cumulative savings capture the impact of upfront costs, if any, to determine how long it may take to recover these costs, especially as the payment of debt service for the initial acquisition financing is required. The relative costs are also important given the size of the overall enterprise. While the illustrative high-level savings may be large, they must also be evaluated in the context of the projected revenue requirement of continued status quo case (referred to herein as the SDG&E Utility Distribution Company [UDC]).

The relative savings are also important because they are being strictly shown on a financial basis and have not been adjusted for any "risk weighting." As discussed herein, there are significant policy, business, organizational, legal, regulatory, and operational considerations, among other factors, that will be weighed in the context of overall feasibility. Both quantitative and qualitative considerations will need to be evaluated in the MEU business model.

A summary of the preliminary economics demonstrating the cumulative benefit of the Original Cost Less Depreciation (OCLD) and the Reproduction Cost New Less Depreciation (RCNLD) models for the 10-, 20-, and 30-year timeframes is shown below in Table ES-1. Financial figures are in millions of dollars ($M) and are in year of expense dollars (YOE$), as discussed herein.

Table ES-1
Summary of Preliminary Economics ($M)(1)

Potential Financial Benefit(1)	Year 10	Year 20	Year 30
$2B Purchase Price			
Estimated MEU Cumulative Benefit ($)	$3,000	$8,000	$15,000
Estimated MEU Cumulative Benefit (%)	13% to 14%	14% to 15%	14% to 15%
$6B Purchase Price			
RCNLD Cumulative Benefit ($)	($60)	$2,000	$6,000
RCNLD Cumulative Benefit (%)	0%	3% to 4%	5% to 6%

(1) For illustration purposes only; actual results will vary.

Subject to the assumptions herein, the preliminary and high-level results indicate that the City may have an opportunity to generate financial benefit, depending on the purchase price and the timeframe to realize such a result. If the City were to acquire the SDG&E electric delivery assets for approximately $2 billion, the cumulative benefit of the MEU to ratepayers might be as much as approximately $3 billion within a 10-year time frame. This represents potential annual savings to ratepayers of approximately 13% to 14% in comparison to continued operations under SDG&E. However, if the City were to acquire the SDG&E assets for approximately $6 billion, the cumulative benefit over the 10-year period might result in a cost (or dissaving) of approximately $60 million.

Over a considerably longer timeframe, the City might be able to generate a potential financial cumulative benefit of between $6 billion (at the higher asset price) and $15 billion (at the lower asset price) over a 30-year period. These projections remain highly theoretical and dependent on several assumptions, market factors, and circumstances both foreseeable and unforeseeable at this time. Further discussion and analysis of the potential results are warranted in connection with any additional analysis. Actual results may vary.

Future Natural Gas Operations

SDG&E provides both electric and natural gas services to the citizens and businesses of the City. As part of the City's CAP, the City set a target to phase out 100% of natural gas usage in municipal facilities and 90% of natural gas usage from existing buildings by 2035. The development of a municipally owned natural gas utility would not be consistent with the City's CAP goals. Therefore, the acquisition of the SDG&E natural gas system was removed from detailed analysis for the Phase I Study.

Recommendations/Next Steps

Based on the preliminary analysis conducted for this Phase I report, it is recommended that the City continue its evaluation of municipalization of the SDG&E electric delivery assets discussed herein. Objectives of the City's Phase II efforts include development of a Municipalization Strategic Plan. This plan will identify and define the City's strategic goals and objectives for forming an MEU, which will incorporate elements of the City's CAP and other policies and documents as appropriate. Phase II will also include a robust strategic engagement process, which will identify and initiate community outreach efforts, including discussions with SDG&E. The results of the strategic engagement process will be incorporated into the Municipalization Strategic Plan, as appropriate. Additionally, the Phase II efforts will include evaluation of the LAFCO application and application process, which may entail additional review of SDG&E asset value, severance issued, and financial analyses. The conclusion of these efforts will be a final Municipalization Strategic Plan and Phase II report, anticipated to be completed by summer 2025.

GLOSSARY

The following is a list of terms frequently referenced in this report and their definitions.

- CAISO – California Independent System Operator
- CAP – The City's Climate Action Plan
- CCA – Community Choice Aggregator
- CEC – California Energy Commission
- CPUC – California Public Utilities Commission
- FERC – Federal Energy Regulatory Commission
- IBEW – International Brotherhood of Electrical Workers
- LAFCO – Local Agency Formation Commission
- MEU – Municipal Electric Utility
- NERC – North American Electric Reliability Council
- OC – Original Cost
- OCLD – Original Cost Less Depreciation
- RCN – Replacement Cost New
- RCNLD – Replacement Cost New Less Depreciation
- SDCP – San Diego Community Power, the City of San Diego's CCA
- SDG&E – San Diego Gas & Electric
- SDG&E UDC – San Diego Gas & Electric Utility Distribution Company
- WECC – Western Electric Coordinating Council

Section 1
INTRODUCTION

The City of San Diego (City) is a special place with immeasurable potential, where everyone deserves equal access to opportunity, happiness, and a bright future. The City exists to serve its citizens and to be a resource for individuals, families, and communities. The City's Strategic Plan under Mayor Gloria is founded on the principles of customer service, community empowerment, equity and inclusion, and transparency. In line with this directive to be responsive to resident needs, the City is actively investigating options to expand public services to include gas and electric utilities. To further this investigation, the City requested proposals for consulting services to provide technical, economic, and policy insight through a Public Power Feasibility Study (Study). The Study is a multi-phased approach to evaluate the processes, costs, risks, and opportunities associated with municipalizing the energy infrastructure assets of San Diego Gas & Electric (SDG&E) within the City.

The City assigned responsibility of the Study to its Sustainability and Mobility Department. The Department's mission includes leading the implementation of the City's Climate Action Plan (CAP), facilitating innovative efforts across multiple City departments to advance equitable, economic, social and environmental sustainability. The Department also leads the City's transition to 100% renewable energy through San Diego Community Power (SDCP) and has manages the administrative oversight of the current SDG&E franchise.

In October 2022, the City announced the award of the Study contract to NewGen Strategies and Solutions, LLC (NewGen). NewGen teamed with Bell, Burnett & Associates (BB&A) and Siemens Power Technologies International (Siemens PTI or Siemens) to provide a robust, multidisciplinary, and dedicated consulting resource to the City to support its needs for this Study.

Current Situation

The City of San Diego's 2022 CAP establishes a goal of net zero greenhouse gas (GHG) emissions by 2035. To meet the magnitude of the climate crisis, the CAP establishes zero-emissions targets for municipal facilities and operations and a 90% reduction in natural gas use citywide. Specific strategies for the City include plans to decarbonize City facilities and increase municipal zero emission vehicles. The City's municipal building portfolio presents significant opportunities to reduce carbon pollution and maximize its climate action efforts. Implementation of these strategies will increase the City's resilience in the face of climate-driven disruptions, advance climate equity, and push the City's building portfolio toward the goal of zero emissions by 2035.

The City's CAP, and specific efforts to reduce GHG emissions, relate to this Study, as electricity generation and natural gas usage are significant contributors to carbon emissions. Municipalizing the energy systems within the City in itself may not directly reduce carbon emissions. However, the ability to control the distribution system, manage rates, and implement policies that aggressively support increased electrification, distributed energy resources, electric vehicle charging, and other initiatives could make CAP targets easier to accomplish under municipal ownership. Additionally, the City's ability to prioritize equitable access and the needs of residents in Communities of Concern would be further enhanced under a municipal ownership model.

Current Municipalization Efforts in California

There are currently two large municipalization efforts underway in California. These are the City and County of San Francisco (CCSF), and the South San Joaquin Irrigation District (SSJID or District). The following is a summary of these efforts, which are described in more detail in Section 2 of this report.

In 2019, the CCSF made an offer to purchase Pacific Gas & Electric (PG&E) assets for a price of $2.5 billion, which was rejected by PG&E. In 2021, CCSF continued its attempts to municipalize by petitioning for an independent state valuation of PG&E's local electric assets which is currently under consideration by the California Public Utilities Commission (CPUC) (Docket P.21-07-012). CCSF filed its Opening Testimony on April 10, 2023. Per the proceeding schedule (as of the date of this report), PG&E's Opening Testimony is due October 13, 2023, with CCSF Rebuttal due on January 8, 2024. Discovery continues in the case.

After continued litigation and favorable court decisions for SSJID, the District made an offer to purchase local PG&E assets in 2016. After PG&E indicated that their assets were not for sale, the District filed in the San Joaquin Superior Court to begin eminent domain proceedings to acquire the assets. In 2018, the San Joaquin Superior Court dismissed SSJID's eminent domain claim, which was then appealed by SSJID to the State of California Appellate Court and conjoined with the continuing litigation regarding the San Joaquin Local Agency Formation Commission (SJLAFCo) approval. In 2021, the Appellate Court ruled in favor of SSJID which PG&E appealed to the California Supreme Court. The Supreme Court denied PG&E's petition for review in 2022 and the Appellate Court has subsequently returned the case to the Superior Court to begin the condemnation process.

Franchise Agreement

The City awarded the current franchise agreement with SDG&E in July 2021, which provides for electric and natural gas services within the City. Specifically, the franchise agreement allows SDG&E to use the City's public rights of way to install and maintain its infrastructure to provide electric and natural gas utility services to the residents and businesses in the City. As consideration, SDG&E collects and remits to the City a franchise fee payment and provides funding for undergrounding electric facilities as well as a series of annual payments (bid amounts). The provisions for the total consideration provided to the City are specified in the agreement.

The franchise agreement includes an Energy Cooperation Agreement (ECA), which aligns with the City's Climate Action Plan goals and advocates for various policies and programs. The ECA also ensures transparency by requiring regular meetings and presentations by SDG&E to City Council regarding energy rates, undergrounding and major projects, customer equity, and climate equity. The franchise ordinance has an initial term of 10 years with an automatic extension of 10 years unless action is taken by the City Council.

Specifically related to this Study, the ordinance includes provisions for potential municipalization of the SDG&E system by the City, including specifications regarding the City's right to terminate the agreement. Additionally, the franchise states that the City reserves the right to acquire the property of SDG&E through eminent domain or voluntary agreement. Additional details on the SDG&E Franchise Agreement are provided in Section 2 of this report.

Community Choice Energy/SDCP

In September 2019, the cities of San Diego, Chula Vista, Encinitas, La Mesa, and Imperial Beach adopted an ordinance and resolution to form San Diego Community Power (SDCP), a California joint powers agency that serves as a Community Choice Aggregator (CCA). In 2021, the County of San Diego and National City joined SDCP as well.

SDCP's governance is set up as a Board of Directors, which is comprised of elected representatives from each member jurisdiction. The Board of Directors is accountable to SDCP ratepayers and hosts monthly meetings for the purposes of establishing policies, setting rates, determining power options, and maintaining fiscal oversight.

As a CCA, SDCP aligns the electric needs of its customers with power from a variety of sources, including a significant portion of renewable energy. However, SDCP does not own the delivery system as SDG&E delivers the electricity through its existing power lines and provides meter reading, billing, and line maintenance services to customers. SDCP coordinates its power supply costs and rate design with SDG&E so that SDCP customers receive a single bill from SDG&E that shows SDCP's electric generation charge. Further, SDCP customers are billed by SDG&E for their utility program fees, power transmission, and distribution fees. While SDCP provides an alternative source of electricity to its customers, it does not offer natural gas service.

SDCP provides service to approximately 93% of the businesses and customers within the City (some customers continue to be provided generation service with SDG&E and other sources for various reasons). For the purposes of this Study, the NewGen Team coordinated with SDCP to review the scope of the analysis for this Phase I report. If the City were to municipalize by acquiring the electric delivery assets within its municipal borders, it is anticipated that SDCP would provide the electric commodity to all customers within the City. This may require additional analysis and potential adjustments to existing contractual obligations between the City and SDCP; however, this additional detail was beyond the scope of this Phase I report.

Future Natural Gas Operations

SDG&E provides both electric and natural gas services to the citizens and businesses of the City. However, continued use of natural gas systems will significantly contribute to the City's GHG emissions. As part of the City's CAP, the City set a target to phase out 100% of natural gas usage in municipal facilities and 90% of natural gas usage from existing buildings citywide by 2035. The development of a municipal natural gas utility would not be consistent with the City's CAP goals. Therefore, a natural gas utility owned by the City would see declining revenues which would challenge its ability to pay back the debt for the asset's acquisition and hence the financial viability of the utility. Based on this, the acquisition of the SDG&E natural gas system was determined to be infeasible and removed from detailed analysis as part of the Phase I Study.

Study Scope

The City's implementation of this Study is anticipated to occur as a series of coordinated and interconnected phases. This report and these recommendations represent the results of Phase I of the Study. The specific elements requested by the City to be included in the Phase I Study are as follows, and are discussed at a summary level below:

- Develop Process Maps
- Review Public Power Entity Options
- Develop initial financial determinations regarding existing electric and gas systems in the City
- Develop initial financial and operational options and needs for a Public Power entity

Approach and Methodology

In general, the approach to the analysis, assessment, and recommendations provided in this Phase I report is based on the experience and professionalism provided by the members of the NewGen Team. The process maps development relied on the NewGen Team's insight from working with the municipalization studies cited above and those for the City of Boulder (Colorado) and Chicago, as well as other smaller communities whose efforts have been supported by members of the NewGen Team over the past twenty years. Further, NewGen has led multiple Stakeholder Engagement events for clients for issues ranging from strategic planning and retail rate designs to other concerns, and this experience informed much of the municipalization processes proposed for the City. Additionally, the NewGen Team has been involved with several high-profile appraisal litigation cases, as well as other regulatory litigation efforts, and that experience assisted in the development of the process maps.

The approach and methodology utilized for the development of the public power entity options and the organizational assessment of the current City operations is based on experience and established procedures created by the NewGen Team. Members of the NewGen Team have worked directly in management roles for municipal utilities in California and have provided various strategic, economic, and financial consulting services for municipal agencies and others for over twenty years. Further, NewGen offers Organizational Assessments as a service offering for a variety of clients, including large municipally owned electric utilities across the country. Combined, this experience was relied upon to develop the list of City employees interviewed and the interview format and questions in Phase 1, as well as to provide insight on the existing organizational structures of electric utilities within the state.

Financial and operational determinations for the existing systems serving the City, as well as those that would be required by a public power entity, utilized the engineering and financial expertise of the NewGen Team. The methodology used to determine the estimated value of the assets to be acquired by the City from SDG&E is provided in detail in Section 5 of this report. This methodology relied upon publicly available information on the transmission and distribution system serving the City and NewGen experience with construction practices in California. This was complemented by data provided by the City regarding the location of various electric distribution equipment utilized to serve the City. Assumptions were made regarding the reproduction costs of this equipment based on industry knowledge and industry-recognized construction cost guides. Various assumptions regarding SDG&E costs and future rates were obtained from publicly available resources, including recently filed rate cases before the CPUC.

The financial analysis conducted for this Phase I Study consisted of the preparation of a high-level Financial Capacity Analysis. This approach estimates the costs attributable to the municipalization effort (Municipal Electric Utility – MEU) and compares them to the current forecasted rates and charges for SDG&E. The Financial Capacity Analysis incorporates the projected operations, maintenance, meter and billing, system planning, and administration costs, as well as preliminary acquisition costs and severance costs. Further, this analysis includes preliminary estimates for high-level capital investment requirements. Assumptions were made regarding the terms and conditions for debt issuance by the MEU to support start-up costs and asset acquisition based on the NewGen Team's experience and expertise in this area.

Process Maps

The City requested the development of a municipalization process map as an element of the Phase I Study. A series of six process maps are presented in Section 10 to provide an overview of the various analysis, decision points, and feedback loops inherent in the City's municipalization decision. As discussed in detail in Section 10, the beginning point for the process maps is the conclusion of the Phase I Study. A time frame along the top of each process graphic has been developed based on the professional experience of the NewGen Team and input from the City. Further, each process map consists of two or more horizontal "swim lanes" which are assigned to an entity or entities and include the activities and the responsibilities of those entities within the lane. The process maps are designed to focus on the City's requirements as it contemplates municipalization. Other entities critical to the municipalization process beyond the City are identified; however, their individual decisions may or may not impact those of the City.

A summary process map titled "San Diego – Critical Path to Municipalization" has been developed to provide a high-level, cursory review of the critical elements of the municipalization process. As shown in Figure 1-1 below, Phase II is anticipated to begin with the delivery and presentation of the Phase I report to the City, anticipated in July 2023. Phase II activities focus on performing in-depth analysis and assessing community support, culminating with the development of a Municipalization Strategic Plan, anticipated to be completed by summer 2025. The results of the Municipalization Strategic Plan will prompt a decision by the City to determine if moving forward with municipalization is warranted. If so, the next step in the process is a decision by the City to apply to the Local Agency Formation Commission (LAFCO) for regulatory approval to form a municipal utility. However, if the City decides not to apply to the LAFCO, the municipalization process is terminated.

It is anticipated that a successful LAFCO decision will allow the City to gain the "Right of Entry" to SDG&E's data, which will allow the City to further refine its estimates of the asset value to be acquired (defined as a critical data point in the Data/Analysis lane of the Critical Path process map). Further, it is anticipated that a successful LAFCO process would result in the beginning of direct negotiations with SDG&E regarding asset acquisition. A non-successful LAFCO application may result in the City deciding to resubmit the application based on any identified deficiencies in its initial application process. A critical element of the LAFCO process is the timing; it is anticipated that this process could take approximately 5 years to complete. However, as summarized above, the SSJID municipalization effort languished for several years through the LAFCO process.

Negotiations with SDG&E may result in the City being able to meet its defined Municipalization Strategic Plan requirements without acquisition of its assets, which could result in the termination of the municipalization process. However, if the City and SDG&E are unable to negotiate a successful agreement, the City may decide to move forward with the condemnation process (Phase IV). The CPUC subprocess, similar to the path taken by the City and San Francisco, is anticipated to occur prior to the condemnation process for the purposes of the Critical Path process map and is more fully described in its own map (see San Diego – CPUC Process in Section 10). The result of the condemnation process is another decision point by the City to decide if the determined asset price is feasible to support development of a municipal utility. It is anticipated that a successful condemnation process will result in further negotiations with SDG&E. These additional negotiations will allow the City another decision point if the final determination supports moving forward. If so, the City may purchase the SDG&E assets and begin utility operations.

It should be noted that moving forward with municipalization exposes the City to various risks. These risks are described in Section 9, and include political, financial, operational, and other types of risk. As it is related to the process maps, it should be recognized by the City that should it decide to terminate the municipalization process, it may be liable for costs incurred by SDG&E up to that point. The quantification of these costs is beyond the scope of this Phase I report, but costs may include legal, regulatory, and other costs incurred by SDG&E in response to the City's actions. Further, as described below, the timing of a successful municipalization is unknown at this time. The NewGen Team has estimated the time required for the various process and subprocesses needed to complete the municipalization; however, this time frame may be impacted by entities beyond the control of the City, which could result in delays and additional analyses not considered for this report.

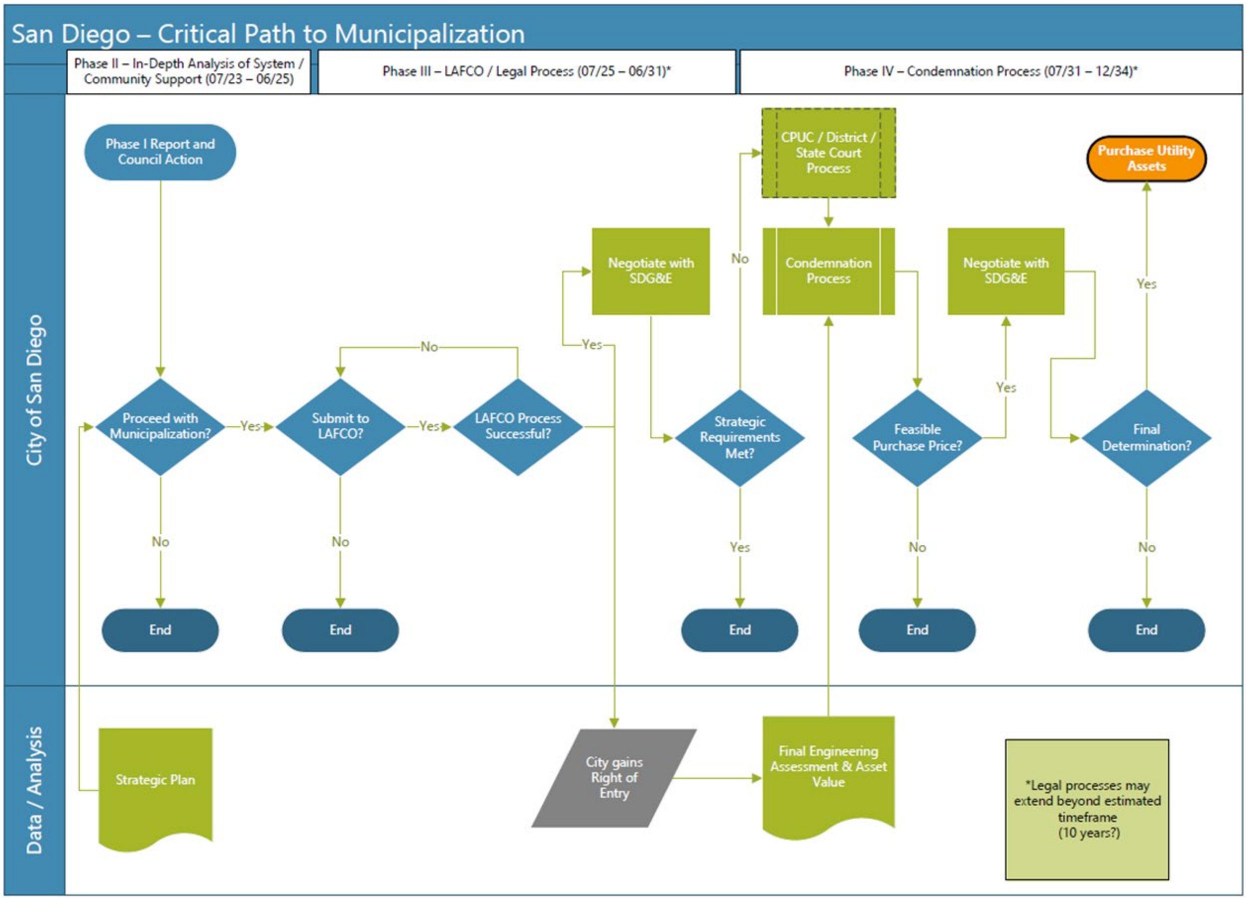


Figure 1-1. Critical Path to Municipalization (Process Map)

Public Power Entity Options

For this Phase I report, the City requested the development of a review of the various options for the structure, governance, and organization of a potential public power entity. To support the public power entity option analysis, an organizational assessment of the current City operations was conducted by the NewGen Team. The focus of this organizational assessment was on the challenges that currently exist within the City relative to the potential establishment of an MEU. The result of the organizational assessment was the identification and evaluation of organizational options for a municipal entity within the City.

Structuring/Governance Options

The NewGen Team reviewed various governance structures for a potential City electric utility. Each potential option comes with advantages and disadvantages, and each has the opportunity to serve the City in a different way. The options identified for this Study have numerous examples within California that the City could consider to inform their decision. The governance options reviewed for this Study include:

- Department of the City
- Separate Board
- Special District
- 501(c)(3)

- Charitable Trust
- Joint Powers Authority

Of the six structure/governance options analyzed for this Phase I report, the "Department of the City" option is the most common structure for municipal electric utilities in California. For example, the existing utility serving the City of Riverside, Riverside Public Utilities, operates as a municipal department within the City's governance structure. There are nine utilities' organizations that operate as a Special District in the state, which primarily serve agricultural load with both irrigation and electric service and typically report to a Board of Directors that is elected by the utility's customers. There are four organizations that are set up as Joint Powers Authorities in the state, which are generally designed to support the development and continued operation of power resources.

Organizational Assessment

As part of the organizational assessment, various parties across several City departments were interviewed to gain insight into the operations of an electric utility in the current City environment. These interviews resulted in the determination of seven primary areas of concern:

- Personnel Systems
- Procurement
- Knowledge of Management/Staff
- NERC
- IT Systems
- Centralized Systems
- Bandwidth

The assessment of the City organization as it exists today suggests that the gap between current capabilities and capacities and the capabilities and capacities needed to successfully operate a large MEU are extensive. The NewGen team notes that the City is aware of this gap and the challenges that they represent.

High-Level Financial Capacity Analysis

The High-level Financial Capacity Results illustrate that municipalization of the electric delivery assets within the City is financial feasibility on a preliminary basis. However, it is important to look at these estimated results on a cumulative and relative basis (see the discussion on Key Considerations and Assumptions in Section 8 of this report). The cumulative savings capture the impact of upfront costs, if any, to determine how long it may take to recover these costs, especially as the payment of debt service for the initial acquisition financing is required. The relative costs are also important given the size of the overall enterprise. While the illustrative high-level savings may be large, they must also be evaluated in the context of the projected SDG&E Utility Distribution Company (UDC) revenue requirement to have some sense of the relative savings.

The relative savings are also important because they are being shown strictly on a financial basis and have not been adjusted for any "risk weighting." As discussed in Section 9, there are significant policy, business, organizational, legal, regulatory, and operational considerations, among other factors, that will be weighed in the context of overall feasibility. Both quantitative and qualitative considerations will need to be evaluated in the MEU business model.

A summary of the preliminary economics demonstrating the cumulative benefit of the Original Cost Less Depreciation (OCLD) and the Reproduction Cost New Less Depreciation (RCNLD) models for the 10-, 20-, and 30-year timeframes is shown below in Table 1-1. Financial figures are in millions of dollars ($M) and are in year of expense dollars (YOE$), as discussed in Section 8.

Table 1-1
Summary of Preliminary Economics ($M)(1)

	Year 10	Year 20	Year 30
Est. Cumulative SDG&E UDC Revenue Requirement ($)	$22,000	$55,000	$100,000
OCLD Cumulative Benefit ($)	$3,000	$8,000	$15,000
OCLD Cumulative Benefit (%)	13% to 14%	14% to 15%	14% to 15%
RCNLD Cumulative Benefit ($)	($60)	$2,000	$6,000
RCNLD Cumulative Benefit (%)	0%	3% to 4%	5% to 6%

(1) For illustration purposes only; actual results will vary.

Subject to the assumptions herein, the preliminary and high-level results indicate that the City may have an opportunity to generate financial benefit, depending on the purchase price and the timeframe to realize such results (see Assumptions, High-Level Financial Capacity Analysis, and Key Considerations herein). If the City were to acquire the SDG&E electric delivery assets at the OCLD value, the cumulative benefit of the MEU might be as much as approximately $3 billion to its ratepayers within a 10-year time frame. This represents potential annual savings to ratepayers of approximately 13% to 14% in comparison to continued operations under SDG&E. However, if the City were to acquire the SDG&E assets at the RCNLD value, the cumulative benefit over the 10-year period might result in a cost (or dissaving) of approximately $60 million. Over a considerably longer timeframe, the City might be able to generate a potential financial cumulative benefit of between $6 billion (at RCNLD) and $15 billion (at OCLD) over a 30-year period. These projections remain highly theoretical and dependent on several assumptions, market factors, and circumstances both foreseeable and unforeseeable at this time (see Assumptions and Key Considerations), and further discussion and analysis of the potential results are warranted in connection with any Phase II analysis. Actual results may vary.

Disclaimer

The assumptions used herein are based on the analysis developed at the time of this report, and there can be no assurance that these assumptions are the only assumptions that should be considered. These assumptions are only based on a point in time, and external events will likely alter them over time. To the extent that external events occur, or new information is available, whether known or not known at the time of the report, that would otherwise impact the assumptions, then the findings in the report, including the estimate of potential costs and revenues, could be adversely impacted. Therefore, **actual results may, and will likely, vary from those contained in this report.**

The words "may," "would," "could," "will," "expect," "should," "estimate," "anticipate," "might," "believe," "intend," "potential," "projected," and similar expressions and variations thereof are intended to identify forward-looking statements. This report contains financial information and makes preliminary and high-level findings based on estimates and projections, including, but not limited to, revenues, expenses, costs, operations, and the capital markets in general. The implementation of an MEU is very complex, and this complexity means, among other things, that there could be any number of factors that could impact the ultimate financial results. **There can be no assurance that the MEU will achieve the estimates contained herein, and results may and could be materially different. Recipients of this should**

make their own investigation of the information and matters described herein, including the merits; costs; and financial, regulatory, and operating risks of the MEU.

Section 2
CURRENT SITUATION

The purpose of this section is to describe the current situation as it applies to the City's utility service and its impact on the City's CAP goals and to provide a review of significant municipalization efforts currently underway in California. The terms and conditions of SDG&E's utility service are described in the Franchise Agreement between the City and SDG&E. Approximately 93% of the electrical load within the City's municipal boundaries is served by SDCP. Further, the City has adopted a series of policies designed to address climate objectives, culminating in net zero GHG emissions by 2035. The City is also mindful of potential future increases in retail electric rates by SDG&E, which could increase as much as 30% through its fiscal year 2027 as reflected in SDG&E's recent rate case currently before the CPUC (see Post Test Year Ratemaking Workpapers – Revised, Exhibit SDG&E 45).

The Current Environment/Franchise Agreement

In 2021, the City adopted Ordinance O-21328 (July 8, 2021), which grants a franchise to SDG&E for the use of the City's streets and rights of ways for the purposes of delivering electricity (the Franchise Agreement). The Franchise Agreement included a bid price as part of the consideration to the City paid by SDG&E. Other elements of consideration include a payment based on a percentage of gross revenues (except from lighting service) as well as a payment based on a portion of gross revenues for the purposes of undergrounding elements of the existing overhead electric distribution system. The Franchise Agreement includes provisions for repayment of the bid amount on a pro rata basis in the event that the City cancels the Franchise Agreement. For the purposes of this Study, the financial consideration on terms in the Franchise Agreement have been included in the section discussing the High-Level Financial Capacity Analysis.

In addition to the compensation, the Franchise Agreement requires a compliance review and report to occur every two years after the effective date of the agreement. Additionally, the Franchise Agreement requires SDG&E to cooperate in good faith with the City's desire to accomplish its climate goals. As part of this effort, SDG&E is required to "reasonably assist" the City in reducing its GHG emissions related to generation of electricity and through the increased electrification of transportation. Additionally, SDG&E is required to cooperate with the City in its efforts to integrate current and future distributed energy resources into the distribution system. Further, the Franchise Agreement states that SDG&E will cooperate with the City toward attainment of environmental and social justice in the provision of electric service. These requirements and others are included in the Energy Cooperation Agreement, the terms of which are defined in the Franchise Agreement.

The Franchise Agreement includes an initial term of 10 years which expires July 7, 2031, and an additional term of 10 years afterwards unless otherwise canceled by either party. For the purposes of this Study, the initial 10-year term provides a time frame for the City to evaluate the prospect of becoming an MEU and to initiate additional analysis, actions, and investigations to determine the financial feasibility of such an endeavor. It should be noted that Section 24 of the agreement states that nothing in the Franchise Agreement impairs the City's right to acquire property of SDG&E through eminent domain or voluntary agreement. The Franchise Agreement does not specify the valuation methodology required by the City; however, it does state that any eminent domain actions, including valuation, would be consistent with the laws of the State of California.

Community Choice Energy (SDCP)

Since January 2022, residents and businesses in the City have had the opportunity to purchase their energy from SDCP, the local CCA. The mission of SDCP is to be a "community-owned organization that provides affordable clean energy and invests in the community to create an equitable and sustainable future for the San Diego region." Its stated corporate vision is to be a "global leader inspiring innovative solutions to climate change by powering our communities with 100% clean affordable energy while prioritizing equity, sustainability, and high-quality jobs."

As indicated above, SDCP provides generation services to almost all the electric load within the City, with some load provided by other entities through Direct Access or continued service from SDG&E.

As currently structured under AB 117 enabling legislation, CCAs are not authorized to provide service within municipal utility service areas. Should the City acquire electric transmission and distribution facilities and provide municipal service, it may be necessary to amend the CCA Act to allow SDCP to continue to provide power to all customers within the City. The specific actions required to determine the necessary changes to the CCA Act (if any) are beyond the scope of this Phase I report.

California Large Scale Municipalization Efforts

There are two large scale municipalization efforts within California that have been underway for decades. These examples provide insight into the complexity, cost, and time involved when a public entity attempts to acquire electric facilities from an unwilling seller. Both examples continue to be works in progress despite having been initiated in the 1990s and the early 2000s. The two case examples are the CCSF (San Francisco) and SSJID (SSJID or the District). Abbreviated summaries of the municipalization processes completed to date for these entities are provided below.

San Francisco

The San Francisco Public Utilities Commission (SFPUC) is a municipally owned utility that supplies high quality water, power, and wastewater services to the citizens and businesses of the City and County of San Francisco (CCSF). These utility services are provided through the maintenance, operations, and development of the SFPUC's three enterprises: the Water Enterprise, the Wastewater Enterprise, and the Power Enterprise.

The SFPUC has provided electricity to City departments and related entities for over 100 years, starting in 1918 and expanding to serve City facilities throughout San Francisco in 1945. The departmental entity of the Power Enterprise was created in February 2005 and is comprised of two retail electric service programs, Hetch Hetchy Power (San Francisco's publicly owned utility) and CleanPowerSF, San Francisco's community choice aggregation (CCA) program.

The Hetch Hetchy Water and Power Enterprise Fund is comprised of two key components: Hetch Hetchy Water, which operates and maintains the Hetch Hetchy Project; and Hetch Hetchy Power, which is responsible for all SFPUC power utility commercial transactions and in-City power operations. The Hetch Hetchy Project is the primary source of power supplying the Hetch Hetchy Power retail electric service program. Recently, Hetch Hetchy Power has grown its retail customer base, designing and constructing new transmission and distribution facilities to serve more retail customers, such as the Hunter's Point Shipyard and the Transbay Transit Center. This expansion has primarily occurred in distinct geographic regions where new development is happening, particularly neighborhoods developed by the Successor

Agency to the San Francisco Redevelopment Authority. Other retail customers, however, may choose Hetch Hetchy Power as their power provider if SFPUC determines the service is feasible.

Part of the SFPUC's long-term business plan is to own a City-wide distribution system to provide electric service to existing and future customers. In some cases, Hetch Hetchy Power does not own transmission and distribution facilities to reach every customer. In these cases, Hetch Hetchy Power relies on the transmission system operated by California Independent System Operator (CAISO) and the distribution system of PG&E, the investor-owned utility operating within the City. The SFPUC must pay CAISO for transmission access and pay PG&E for the use of its distribution system through the Wholesale Distribution Tariff (WDT). The rates for WDT are regulated by the Federal Energy Regulatory Commission (FERC). In recent years, the rates for these services and PG&E's restrictions on the City's use of PG&E facilities have led to ongoing disputes and litigation between the SFPUC and PG&E. This complex relationship with PG&E—as both a competitor and a partner—is a major feature in Hetch Hetchy Power's strategic operations. The Hetch Hetchy Power program currently serves about 4,500 retail accounts.

In 2004, the City and County of San Francisco established and elected to implement a CCA program, now known as CleanPowerSF. However, it was not until May 2016 that CleanPowerSF began serving customers. Under a CCA structure, the incumbent investor-owned utility (in this case PG&E) provides delivery services (transmission and distribution) and customer service (billing, metering, etc.) and the CCA provides power supply. CleanPowerSF aggregates the electricity demands of the residents and businesses it serves to buy electricity on behalf of those customers. CleanPowerSF, which currently serves over 380,000 accounts, gives residential and commercial electricity consumers in San Francisco a choice of having their electricity supplied from clean renewable sources, such as solar and wind, at competitive rates. As of 2022, CleanPowerSF does not own any of its own power infrastructure, and instead either enters into long-term contracts for storage or power products called "power purchase agreements" or "PPAs" or purchases power on the wholesale market to procure its supply.

As indicated, CCSF is currently evaluating the potential of obtaining the delivery assets of PG&E within its municipal boundaries to form an MEU that would serve all citizens and businesses. The first feasibility study that explored the potential municipalization of electric service in CCSF was commissioned in 1996. The San Francisco Local Agency Formation Commission (SFLAFCo) began evaluation of forming a Municipal Utility District (MUD) in CCSF in 2000.

In 2015, SFPUC redesigned CleanPowerSF to utilize expertise and resources existing in the SFPUC Power Enterprise. In 2015, the CPUC approved CleanPowerSF's CCA implementation plan. The CCA began supplying power within San Francisco in 2016.

In 2019, CCSF made an offer to purchase Pacific Gas & Electric (PG&E) assets within the city for a price of $2.5 billion. PG&E quickly rejected the offer and stated that "San Francisco-based facilities are not for sale."[1] In 2021, CCSF continued to attempt to municipalize by petitioning for an independent state valuation of PG&E's local electric assets which is currently under consideration by the CPUC (Docket P.21-07-012). CCSF filed its Opening Testimony on April 10, 2023. Per the proceeding schedule (as of the date of this report), PG&E Opening Testimony is due October 13, 2023, with CCSF Rebuttal due on January 8, 2024. Discovery continues in the case.

South San Joaquin Irrigation District

SSJID began efforts to acquire existing PG&E electric transmission and distribution assets within its service area in 2004 with its governing Board's approval to proceed with an application to the local SJLAFCo. The

[1] Letter dated October 7, 2019, from William D. Johnson to Mayor London Breed and Mr. Dennis Herrera.

first application was denied by the SJLAFCo in 2006, based upon the SJLAFCo opinion that an eminent domain proceeding would be “inappropriate.” After numerous feasibility studies, SSJID again applied for SJLAFCo approval in 2009. The SJLAFCo process led to additional engineering and financial analysis, this time leading to approval of the application in 2014.

In 2015, PG&E filed a lawsuit in the San Joaquin County Superior Court to overturn the SJLAFCo decision. After continued litigation and favorable court decisions for SSJID, the District made an offer to purchase local PG&E assets in 2016. PG&E indicated that their assets were not for sale and the District filed a lawsuit in the San Joaquin Superior Court to begin eminent domain proceedings to acquire the assets. In 2018, the San Joaquin Superior Court dismissed SSJID’s eminent domain claim, which was then appealed by SSJID to the State of California Appellate Court and conjoined with the continuing litigation regarding the SJLAFCo approval. In 2021, the Appellate Court ruled in favor of SSJID which PG&E appealed to the California Supreme Court. The Supreme Court denied PG&E’s petition for review in 2022 and the Appellate Court has subsequently returned the case to the Superior Court to begin the condemnation process.

The Superior Court had set the trial date on PG&E’s challenges to the condemnation for May 28, 2024. The court then heard and ruled on PG&E’s motion on the standard of review for the trial court to apply in the right to take trial which PG&E claimed should be independent judgment by the court. The court ruled against PG&E and agreed with SSJID that the appropriate standard of review is the gross abuse of discretion given that the resolution of necessity is a quasi-legislative decision. PG&E filed a Writ Petition with the Appellate Court challenging the trial court’s ruling. Since last fall, the SSJID law team has been drafting appellate briefs to uphold the trial court’s decision, and SSJID has been joined by the League of California Cities, the California Municipal Utilities Association, and the Association of California Water Agencies (ACWA) as amici to the court. The Writ Petition has been fully briefed and SSJID is waiting to hear when the oral argument will be set. SSJID expects a new trial date for May 2024 as set by the Superior Court.

Section 3
GOVERNANCE AND ORGANIZATIONAL ASSESSMENT

The purpose of this section is to describe the results of the organizational assessment of the current City operations conducted by the NewGen Team. This organizational assessment focused on the challenges that currently exist within the City relative to the potential establishment of a municipal electric utility. This section identifies and evaluates various organizational options that the City may consider if it moves forward with the acquisition of the SDG&E assets within its municipal boundaries. At the conclusion of this section, the NewGen Team provides its recommendations for the organization options and additional analyses.

Key Considerations

Should the City decide to proceed with the potential acquisition of SDG&E's electric delivery assets within its municipal boundaries, it faces complex choices and difficult decisions regarding structural governance options, provisions for policies, procedures, internal service options, and staffing. The methodical, structured approach employed by the City in this effort is prudent and wise, as it provides the opportunity to study and plan for these important decisions and to contemplate the structure and look of a potential municipal electric utility. The observations for this Study are provided more for context than for final decision making. It is recommended these matters be explored in greater detail should the City decide to continue its review of creating a municipally owned electric utility. In any case, the City's process has provided for sufficient off-ramps should any fatal flaws be discovered. However, as of this point in the Study, even with the challenges identified herein, no fatal flaws have been identified with the City proceeding with its municipalization effort.

Utility Operations

A future electric utility will have operational needs that need to be established regardless of the chosen governance structure. These structures and processes would include:

- Personnel
- Customer Service
- Operations & Maintenance
- Planning and Procurement
- Billing and Metering Systems
- IT and Security
- Engineering & Planning
- Finance and Rate Setting

This section is intended as an overview of typical utility operations, followed by more detail associated with specific options for governance structures. For more detail regarding typical utility operations, including a sample organizational chart, refer to Section 4 of this report.

Personnel

One of the most obvious and important steps to establishing an electric utility will be hiring personnel. The electric utility industry nationwide is facing a difficult hiring environment with stiff competition for the skilled operators required for safe and reliable operations.

In addition to technical staff, the utility will need personnel to fill supporting departments. People hired to operate and maintain finance, planning, and procurement will likely need to already have some experience with a power utility and its unique requirements. Hiring will need to be able to move swiftly as shortages can have far-reaching and potentially severe impacts.

Billing and Metering Systems

The systems used for systems operation and customer billing and accounting are quite complex. SCADA, Outage Management Systems (OMS), Advanced Metering Infrastructure (AMI), and customer billing systems are some of the most important systems to the successful operation of a municipal utility, as together they form the cash register of the business (AMI and billing) as well as the link from human oversight and monitoring to mechanical/electrical reliability.

Customer Service

Similar to other customer-facing service providers, a new utility will need a customer service department to handle customer needs. With a robust, well-designed, and well-managed website, many customer service inquiries can be handled online (such as general inquiries, bill pay, etc.), but staff will need to be well trained to handle customer interfacing during outages, particularly during storms; more advanced questions on services; and questions regarding possible discrepancies.

Operations and Maintenance (O&M)

As an MEU, the City would need to create a Transmission and Distribution (T&D) O&M Division that would be responsible for the operations, maintenance and building of the transmission and distribution system. The T&D O&M Division would be responsible for ensuring that the system is consistent with federal and state electric standards, as further discussed in Section 4. Generally, the functions of this division would be organized into two primary departments (one for transmission systems and one for distribution systems). This division would also require a central office and supporting departments for fleet management and purchasing/inventory management.

IT and Security

Any new utility will need to have a robust, dedicated IT team or department, as potential problems would have the ability to cripple the electric system. For example, a ransomware attack could result in the complete shutdown of the distribution system.

Security is becoming increasingly recognized as a critical part of business operations. Because of the critical nature of electric service, the need to prioritize security is even more important. Customer data, system integrity and reliability, and public safety are all negatively impacted by security breaches. For example, customer data that is exposed to the internet could have severe financial consequences for the MEU's customers.

Planning and Engineering

The City MEU would require a Planning and Engineering Division that would provide engineering services for all aspects of the transmission and distribution business. Specialty type engineering provided by this division would include construction contracts, project management, and contract administration. This Division is typically organized into four departments: Distribution Planning, Transmission Planning, Major

Construction, and Engineering & Standards. Additional information on the potential organizational structure of the MEU is provided in Section 4.

Planning and Procurement

Electric utilities regularly look out five to ten years when considering the maintenance, improvements, and expansions they intend to make to the system to maintain a reliable service to current and future customers. Considering the importance of this planning and the cost associated, long-term planning will be one of the most important concerns for the utility. In addition to long-term planning, the utility needs to be ready to deal with unexpected repairs as they arise. Given the size of the electric system and the general cost of supplies needed to maintain an electric system, this threshold will need to be higher than that of typical government operations for effective electric utility operations. An electric utility, no matter the choice of organization, would need processes for procurement and contract structures that include allowances to make purchases quickly in general and immediately in an emergency that are suited for the operations of a large electric utility.

Finance and Rate Setting

For an MEU, many aspects of finance and accounting needs would look similar to those of other business functions. A particularity of finance for the MEU is the need to establish retail rates to recover expenses. In 2010, voters in California approved Proposition 26 which amended the State Constitution to define a "tax," and provided specific exceptions which apply to municipal electric utility rates. The exception is for "a charge imposed for a specific government service or product provided directly to the payor that is not provided to those not charged, and which does not exceed the reasonable costs to the local government of providing the service or product."[2] This becomes an important factor in electric ratemaking. Electric cost of service and ratemaking for an MEU is unique and can be challenging.

Establishing rates will require an understanding of the business operations of the utility; power market (even if provided by SDCP) and delivery pricing and trends; regulations unique to supplying power, transmission, distribution, and customer services; and City goals and needs. Rates established by the electric utility will need to balance City priorities such as economic development, decarbonization through electrification, expansion of distributed resources, and support of low-income families with traditional utility priorities such as rate equity and minimization of subsidization across customer classes. As previously mentioned, SDCP will continue to provide the electric supply to the majority of City load. However, the unique rates and services offered by the MEU may need to be developed in coordination with those provided by SDCP (such as specific DER, EV and time of use rates).

Structuring/Governance Options

The NewGen Team was tasked with reviewing possible governance structures for an MEU. There are several options available to the City which have yet to be vetted by the City Attorney's Office. It is critical that the City Attorney's Office verify that the alternatives under consideration are currently allowed under the City's governance structure. Each governance option comes with advantages and disadvantages, and each has the opportunity to serve the City in a different way. Several options have numerous examples within California that the City could consider to inform their decision. The governance options reviewed for this report include the following:

[2] Proposition 26, Section 3. (b) (2).

- Department of the City
- Separate Board
- Charitable Trust
- Special District
- 501(c)(3)
- Joint Powers Authority

Under all the governance options evaluated, it is assumed that the commodity portion of electric service (power supply) will be provided by SDCP to all customers within the City. Data provided by SDCP and follow-up interviews indicate that SDCP currently serves approximately 93% of the electric load within the City, and that SDCP anticipates that they will continue to be able to serve this load for the foreseeable future. However, as previously noted, given the current status of the SDCP, there may be a need to have the SDCP contract restructured prior to SDCP directly serving the MEU.

Department of the City

An electric utility as a department of the City would, on the surface, appear to be one of the easiest options to implement as many of the support systems have already been established. However, the size and complexity of the operation could present a significant challenge to the City. The ability of current City systems to serve a municipal electric utility adequately and effectively is discussed in the Organizational Discussion sub-section below.

Advantages include:

- Central services including human resources, purchasing, and finance among others needed to operate the MEU already exist, although it is questionable how feasible it may be to integrate an operation with the size and scope of the new City department.
- The City may be able to achieve economies of scale between departments using shared services.
- Department has increased transparency and accountability to City Council.

Disadvantages include:

- Central services may not be structured in a way that fulfills an electric utility's needs, such as procurement, IT, and Safety and Security.
- While some efficiencies will be accomplished by using central services, the City will still need to hire and onboard nearly the same number of staff that would be needed if it were to start these departments from scratch for the possible Electric Utility.
- Current staffing of central services likely does not have all the necessary expertise needed to support the added workload and unique complexity of an electric utility.
- Current personnel classifications are misaligned to electric utility needs and would need to be expanded to accommodate the unique requirements associated with MEU staffing.
- The influx of electric utility data and needs would likely overwhelm existing shared IT systems. The scale and scope of the IT systems would need to be expanded dramatically, especially considering increased cyber security requirements as detailed in the North American Electric Reliability Council (NERC) discussion later in this section.
- City processes can be long and arduous, limiting the ability of the electric utility to act quickly in non-emergency activities.
- The MEU would compete with other policies and public service priorities of the City (public safety, homelessness, etc.). The City Council's required focus and attention to the MEU could reduce its ability

to focus on City items that *only* the Council can address such as public safety, homelessness, and other public policy related issues.

Table 3-1 provides a summary of examples of California MEUs that operate as a department within their respective cities. Other than the Los Angeles Department of Water and Power (LADWP), most are small to medium sized cities. LADWP has evolved as a department of Los Angeles over 100 years and has its own extensive operating capital and customer support systems integrated into its day-to-day operations. Most smaller MEUs rely more heavily on city provided services for everything from human resources to purchasing, warehouse, fleet, and other related services.

Table 3-1
Electric Utility as a Department of the City (California)

Alameda Municipal Power	City of Lompoc Electricity Department
Anaheim Public Utilities	Los Angeles Department of Water & Power
Azusa Light & Water	City of Palo Alto Utilities
Banning Electric Utility	Pasadena Water & Power
City of Biggs Electric Utility	Redding Public Utilities
Burbank Water & Power	Riverside Public Utilities
City of Cerritos Electric Utility	Roseville Electric
City of Colton Electric Utility	City of Santa Clara – Silicon Valley Power
Glendale Water and Power	Shasta Lake
Gridley Electric Utility	Ukiah Public Utilities
Healdsburg Electric Utility	Vernon Public Utilities
Lodi Electric	

Electric Board

Another governance option is to have the MEU set up as a public entity with a separate governance board, which could be the City Council. For this option, the City Council would act as the Electric Board. This structure is already utilized within the City to govern the San Diego Housing Commission. Alternatively, the City Council could appoint an Electric Board, which is the case with the City of San Francisco and the SFPUC (the MEU serving portions of San Francisco as previously discussed.) With this option, the City would need to evaluate if using central services or creating separate services would better serve both the new utility and the existing City departments.

Advantages include:

- Board meetings are dedicated solely to issues related to the electric utility.
- Utility is governed by a different section of the municipal code.
- Transparency is established through annual financial and compensation reports.
- Boards adhere to state law requirements pertaining to public meetings, bonded debt, record keeping, and elections.
- Board able to prioritize City sustainability goals to a greater extent than SDG&E.

Disadvantages include:

- Stretches the bandwidth of the Council members.
- Requires establishment of a new Board, including development of appropriate ordinances and regulations.

Table 3-2 provides a summary of examples within California where the municipal electric utility is governed by an Electric Board.

Table 3-2
Electric Utility Reports to an Electric Board (California)

San Francisco Public Utilities Commission (SFPUC)

Special District

A Special District is a type of local government created under state law to deliver specialized services to a community. These districts can be any size, serve any number of people, and provide a variety of services and are generally created by public referendum. Special Districts are often created to maintain critical infrastructure and keep up with ever-changing technologies. Funding for utility-based Special Districts typically comes from the rates charged to provide services. Special Districts generally have independent elected boards that govern their activities. Many Special Districts in California, particularly irrigation districts, serve both water and power customers.

Advantages include:

- Boards are elected by the district's voters, giving them direct accountability to the voters and ratepayers.
- Transparency is established through annual financial and compensation reports that are required to be submitted to the State Controller.
- Boards adhere to state law requirements pertaining to public meetings, bonded debt, record keeping, and elections.

Disadvantages include:

- Requires increased coordination between the Special District and the City to complete some projects or goals.
- City policies and procedures would not directly govern this independent entity.

Table 3-3 provides a summary of examples where a community-owned electric utility is governed by a Special District.

Table 3-3
Electric Utility is Governed by a Special District (California)

Imperial Irrigation District	South San Joaquin Irrigation District
Lassen Municipal Utility District	Trinity Public Utilities District
Merced Irrigation District	Truckee Donner Utilities District
Modesto Irrigation District	Turlock Irrigation District
Sacramento Municipal Utility District (SMUD)	

501(c)(3) Organization

Although rare, it is possible to establish a 501(c)(3) organization to run an MEU. Such organizations are in reference to Section 501(c)(3) of the Internal Revenue Code, which states that such an organization must be tax-exempt and not benefit any private shareholder or individual and may not participate in any campaign activity for or against political candidates. Often, 501(c)(3) entities are referred to as charitable organizations. The 501(c)(3) entity would operate as a public entity solely owned by the City. Such an entity would have a separate Board with the responsibility of overseeing operations and maintaining accountability to the ratepayers.

In the past, the City had a 501(c)(3) organization established to provide IT services to the City. This 501(c)(3) was called San Diego Data Processing Corp. This entity no longer exists; however, it may be prudent in future analysis on this topic to understand both its setup and its ultimate dissolution. Currently, the NewGen Project Team is unaware of any municipal electric utilities in California or elsewhere that are run as a 501(c)(3) organization.

Advantages include:

- Structure is in place for City.
- Could fit within the existing bandwidth of the City Council.

Disadvantages include:

- Not in common use, which could result in delays of its approval before the LAFCO because of the increased due diligence and review requirements.

Public Charitable Trust

An additional option is to create a Public Charitable Trust to operate as a municipal electric utility (this may be in conjunction with or separate from the 501(c)(3) entity previously discussed). The utility company that became Citizens Energy Group in Indianapolis was established as a public charitable trust in 1887.[3] Its purpose was, and remains today, to provide safe, reliable, and affordable energy to the city while preventing the assets from being purchased by the large energy monopolies of the day. Currently, this Public Charitable Trust serves 800,000 people and provides natural gas, thermal energy (steam), water, and wastewater services (however, it does not provide electric power). The organization is structured such that if the Public Charitable Trust continues to fulfill its mission, it can never be sold to a private entity. The entity is governed by a self-perpetuating governance structure with the current Indianapolis mayor maintaining a permanent seat on the Board. The City could set up a similar public charitable trust for the purpose of providing municipal electric utility services to the community.

Advantages include:

- Could fit within the existing bandwidth of the City Council.
- Provides a measure of accountability.
- Ensures the proper focus of the utility on safe, reliable, and affordable services.

---

[3] Citizens Energy Group, a locally owned and operated utility service company, provides natural gas, thermal energy, water, and wastewater serves in the Indianapolis area.

- The initial board could be either elected or appointed by the mayor and council, ensuring the Board's focus on City priorities.

Disadvantages include:

- May be difficult to enact.
- Not in common use, which could result in delays of its approval before the LAFCO because of the increased due diligence and review requirements.

To the knowledge of the NewGen Team, Citizens Energy Group is the only utility operating under a Public Charitable Trust, and there are no Public Charitable Trusts operating municipal electric utilities in California.

Joint Power Authority

The City could consider allowing its municipal electric utility to be governed by a Joint Power Authority (JPA). A JPA is a legally created entity that allows two or more public agencies to jointly exercise common powers and utilize resources to achieve common goals. A JPA would be expected to have a separate governing body outside the control of the City Council.

Advantages include:

- Would allow public agencies to provide shared services more efficiently.
- Would allow City Council to focus on City priorities.

Disadvantages include:

- The City would need to find a suitable partner, perhaps an organization that has electric utility operating experience.
- The City Council would not have sole responsibility to establish policies for the separate authority.

Table 3-4 provides a summary of where a community-owned electric utility is governed by a JPA in California.

Table 3-4
Electric Utility is Governed by a Joint Power Authority (California)

MSR Public Power Agency	Tri-Dam Power Project
Power and Water Resources Pooling Agency	Tuolumne Public Power Agency

Summary

The City does not need to make a decision regarding its municipal electric utility organization at this time. If the City moves forward with its municipalization process, there will be an opportunity to develop a more detailed analysis of its organizational options before a final decision is required. However, the City should consider which option best fits its needs as it continues to move forward with its municipalization effort.

Organizational Assessment

Approach

As a part of this report, the NewGen Team assessed the current management and operating resources and capabilities within the City as they relate to MEU operations. The purpose of this assessment was to identify the gaps to be addressed in taking over operations associated with purchasing SDG&E electric delivery assets in the City and to offer possible governance structures for a municipally owned electric utility.

In January 2023, the NewGen Team traveled to San Diego to conduct in-person interviews with representatives of various City departments, including Finance, Planning, Public Utilities Department (PUD), Sustainability and Mobility, and the City Attorney's Office (CAO). Additional interviews were conducted remotely due to scheduling conflicts. The interview process included specific written questions as well as open discussion on the topic of municipalization in a confidential setting. However, the focus of the interviews is summarized in the following questions:

1. What is the biggest concern if the City were to operate as an MEU?
2. How does your department presently function in relation to how it would support an MEU?
3. What gaps exist that would need to be addressed before the City can effectively own and operate an MEU?
4. What future MEU governance options are available and/or feasible for the City (as appropriate)?

Biggest Concern

As indicated, the first question asked of the interviewees was to describe their biggest concern associated with the City operating as a municipal electric utility. Figure 3-1 provides a summary graphic of the responses as indicated by the number of respondents for each area of concern (some respondents provided more than one concern). The most common areas of concern were those regarding future risks, system reliability, and bureaucracy (each area of concern had four individual responses). Staffing and the impact on general services and governance structure were also identified as areas of concern, with three, two, and one responses, respectively. One respondent indicated that they had no concerns regarding the City operating an MEU.

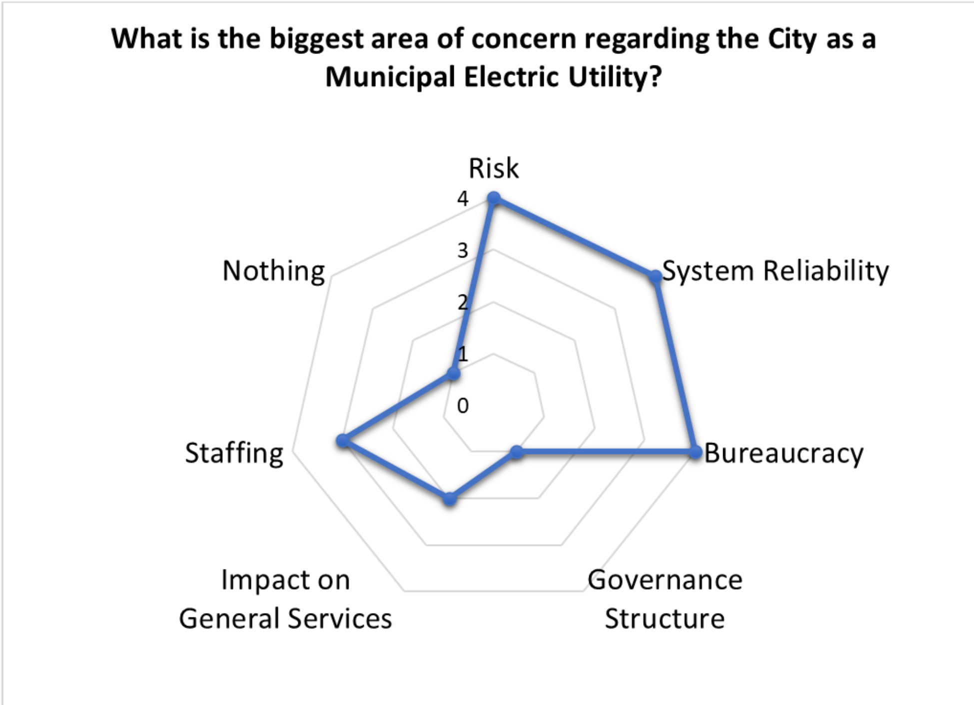


Figure 3-1. Biggest Area of Concern – Responses from City Interviewees

Findings

To establish how certain processes and systems function presently, various parties across several departments were interviewed to gain insight into the operations of an electric utility in the current City environment.

The NewGen Team's findings resulting from the interview process generally fall into seven categories:

- Personnel Systems
- Procurement
- Knowledge of Management/Staff
- NERC
- IT Systems
- Centralized Services
- Bandwidth

Personnel Systems

One of the first and most obvious concerns with creating and supporting an MEU is staffing. Under the current systems, all staffing is resourced through the same policies, procedures, and processes that serve the City. New personnel classifications, particularly for highly technical positions, can be difficult to establish due to the need to go through these processes. Similarly specified positions tend to be compared to one another. For a large complex entity such as the City, there can be challenges presented by these position classifications. For example, for many of the municipally owned electric utilities, there is ongoing competition with the private sector for engineering positions. Civil, mechanical, water, and electrical engineering positions can present classification and compensation challenges for publicly owned entities, particularly when compared to compensation in the private sector.

Another challenge appears to be the ability to fill vacant positions in a timely manner. Several mission critical areas for the City currently reported having vacancy rates as high as 25–50% for authorized positions. Hiring often takes many months and keeping up with turnover can be an arduous task.

Another concern expressed during the interviews related to hiring centered around salary. Salary expectations for employees of an electric utility are often higher than those associated with other City positions. Having to adhere to salary bands that apply to all City employees would put a new electric utility at a distinct disadvantage when seeking out qualified, experienced staff to maintain and operate the electric assets. This is a difficulty that many municipal utilities face, and the City would be no different. In fact, SDG&E made the following statement in its 2024 General Rate Case Application:

> *The recent COVID-19 pandemic and other societal challenges have resulted in increased pressures associated with maintaining a highly trained and qualified workforce. Increased turnover, due primarily to retirements and employee movement as a result of promotions and transfers, and a competitive labor market, continues to pose challenges to SDG&E, particularly in the areas of knowledge transfer, skills development, and overall proficiency of the replacement workforce. SDG&E's ability to attract and retain a skilled and dedicated workforce requires adequate funding for employee training, compensation and benefits, and human resources.*[4]

Procurement

Often, procurement moves slower in city government than in the private sector, and this holds true for the City as well. Procurement processes are time consuming and are often governed by policies which spread the responsibility across departments based on contract or funding type. In an MEU operation, the need to be nimble is important to everyday business. Procurement delays create operational, safety, and reliability concerns resulting in heightened risk to electric utility service and its customers. Reliability is dependent on being able to respond quickly and effectively to outages, maintenance requests, and other necessary requirements for electric transmission and distribution systems.

In addition to the procurement processes, current City policy requires purchases or contracts over certain thresholds to be approved by City Council. The necessity to get on the City Council docket, particularly with the myriad of time-sensitive issues of City-wide importance that the Council must entertain, can cause delays with potentially severe consequences to the operations of an MEU. When considering that large municipal utilities manage assets in the billions of dollars, the NewGen Team believes that the current requirements are too low of a threshold for City Council's approval in relation to electric utility scale, operations, and capacity to act quickly. Though approval thresholds may be addressed through municipal code changes, it is important to consider these additional steps when considering the governance options.

Knowledge of Management/Staff

A significant gap in undertaking the operation of an MEU is management and staff knowledge. During the interview process, no individual on the current City staff was identified that has the qualifications, background, and skills to manage an electric utility. Finding qualified personnel for both management and staff and getting them onboarded would be a significant but achievable undertaking. The majority of the personnel required for initial MEU operations should be individuals that already have knowledge and experience in the power sector. The City would need to work closely with the local International

[4] Application of San Diego Gas & Electric Company (U 902 M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2024, p. 4.

Brotherhood of Electrical Workers (IBEW) in the early stages to ensure that the electric utility can be staffed up appropriately and in a timely manner. The City should not expect to be able to just hire SDG&E staff to fill roles similar to their current roles with the new electric utility. Even with the development of a City MEU, SDG&E would still be operating and continue to require staff. Further, any SDG&E staff whose jobs are eliminated as a result of the formation of an MEU would likely have multiple employment opportunities in the industry within California as well as throughout the United States.

NERC

The NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the electric grid. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the FERC and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves nearly 400 million people. Under the proposed system operations and financial model, an MEU would own limited transmission assets and, as a result, would require compliance with NERC. Current NERC standards are presented in Section 4. NERC compliance can be expensive and requires constant vigilance by the MEU. The cybersecurity regulations are particularly of note in this instance, as they would most likely require a completely separate IT organization not centralized with the City's existing services.

IT Systems

Similar to other business systems, IT is a City function that serves all departments. Currently, IT requests are put into a central queue and prioritized with requests made by other departments. In many municipal entities, the demands on IT exceed the capacity of the organization. When this happens, it can lead to a "fire drill" style of prioritization. The issues that get priority are the ones with the most immediate needs. While this may not be problematic, it may prevent departments from being able to work proactively to improve their current IT systems.

If the City moves forward with forming an MEU, metering assets would be included in the acquisition. While the City would be responsible for the maintenance of these assets moving forward, establishing the billing software, systems, and protocols would be the more immediate need. Discussions with the City's PUD indicated improvements to the existing water/wastewater billing and customer information systems, in addition to staffing challenges, are a frequent cause of customer frustration. Respondents during the interview process indicated that it is not unusual to have a City PUD customer wait times of 2 hours or more. Adding new electric billing and customer information systems to handle the capacity of an MEU in the current environment could present an IT challenge that could be overwhelming.

Additionally, the cybersecurity elements required for NERC compliance would most likely require a completely separate IT organization.

Centralized Services

Individual aspects of centralized services are addressed above; however, departments of the City share numerous other centralized services. This style of services can allow the City to save on various costs by having central services for finance, planning, human resources, legal, purchasing and warehouse, and IT, among others. Coordination between departments may be easier by having shared services. However, these advantages must be weighed against possible difficulties in supporting the MEU. When prioritizing projects, staff must try to consider every function of the City, potentially pitting departments against each other in their attempt to achieve what they perceive as the most important priority. It is often difficult for a central service provider to weigh whether a water request, road request, or finance request should be fulfilled first when all are pivotal to the efficient and effective functioning of the City. The City may wish to consider separating some of the centralized services for complex operations such as an MEU.

Bandwidth

Another key consideration of a future municipal electric utility is the role of City Council and Mayor. Using PUD as a proxy, the NewGen Team was provided with some insight into the City Council's role if an MEU were to become a department of the City. City Council would be involved in many operations of the utility: approving contracts and procurement, discussing and approving rate increases, and setting priorities, to name a few. While City Councils in California generally fill this role, including councils in Los Angeles and many others as noted in Table 3-1, San Diego's City Council has a responsibility for a city that is the eighth largest in the country. City Council would have to familiarize themselves with the needs and its unique considerations of an MEU.

There are numerous ways to approach governance that would not require City Council to further divide its attentions when the City has needs that only City Council can address, such as homelessness, land development goals, and public safety. Adding an MEU to the current governance would further stretch City Council's bandwidth to respond to its daily challenges and public policy implementation objectives.

Conclusion

For the City to establish an MEU, there would be challenges to using existing City resources, policies, and structures without significant upgrades to systems and staffing and an overhaul of certain policies and procedures. A detailed implementation plan would be required to assure a smooth transition. It may be preferable to create certain services independently rather than attempting to shoehorn them into existing City services and departments. The following challenges from the organizational assessment as they apply to the City's potential municipalization effort have been identified:

- **Systems:** The impacts on support systems required by electric service and delivery are more complicated and challenging than similar systems maintained by the City. IT, particularly as it relates to asset management, maintenance, operations, billing, and customer service, would require considerable effort. Likewise, given the technical nature of the business, personnel and staffing resources may require upgrades to existing systems (personnel, IT, procurement billing, general ledger, Geographical Information System [GIS], Supervisory Control and Data Acquisition [SCADA], budgeting, and capital planning, to name a few). Departments that provide shared services are currently at capacity and would not likely be able to support an MEU without additional resources and significant changes in internal processes.
- **Procurement:** The unique purchasing, supply chain, inventory, and technical requirements of electric utility operations would require modifications to existing procurement systems to ensure efficient operation and maintenance of a substantial asset base. The current processes and approval requirements are likely not well suited to meet an MEU's needs.

- **Policies:** It is anticipated that widespread changes and upgrades to existing policies would be necessary to integrate the new business aspects of an MEU. Examples include purchasing, material acquisition and maintenance, personnel, and staffing policies.
- **Staffing:** The unique planning, asset management, operation, maintenance, and general business requirements of an electric utility result in the need for detailed engineering, safety and training, and customer service requirements. These would require significant consideration, particularly the need to have technically competent staffing requirements fulfilled prior to MEU operations. There are also labor and management considerations that need to be identified and managed including significant union agreements and communications. Accordingly, the City would need to begin coordinating with the existing local IBEW utility workers chapter early in the acquisition process to make the hiring process as smooth as possible.

Should the City proceed with the formation of an MEU, the governance structures noted above could possibly resolve many of the planning and operational challenges identified. Certain governance options allow for greater autonomy and flexibility than others to manage many of these challenges. Ultimately, these decisions would need to be made by the Mayor and City Council. The most promising structures identified and studied for this Phase I report that meet the requirements of the City and the needs of an MEU are the Public Charitable Trust or Special District options.

Other structural options may be workable, but attention would need to be given to the organizational challenges identified above. The least desirable option identified, based on discussions with City staff and independent observations, is to establish an MEU as a department of the City. The existing policies, operating and governance requirements, and necessary expansion of City Council bandwidth make this option less desirable. This is because the size, complexity, and risk profile of an MEU would also constitute a significant increase in the bandwidth and expertise required of the City.

Section 4
OPERATION, MAINTENANCE, METERING AND BILLING, SYSTEM PLANNING, AND ADMINISTRATION

Structure

A potential organizational structure for the MEU incorporates the considerations discussed in Section 3 as well as herein. These considerations are based on the NewGen Team's current knowledge of the City and its requirements for an MEU. However, it is important to recognize that these considerations could change over the time frame required to form an MEU and that this organizational structure may not represent the final structure of the City's potential MEU.

- The MEU will be in charge of delivering electric power to its customers which is procured by a third party (e.g., SDCP). The MEU will be a "wires only" utility and the MEU will not own or procure significant sources of generation.
- The MEU will be a medium-sized utility (approximately 700,000 customers) and will own and operate electric transmission and distribution (T&D) systems. Electric distribution will be the largest function of this utility, representing approximately 74% of the asset's costs (based on Reproduction Cost New [RCN]) and 69% of the operations and maintenance (O&M) costs, as shown in Figure 4-1. Based on this, T&D costs could be integrated at the first line under the General Manager (Division) for the various separate functions of O&M and System Planning and Engineering.
- The MEU will be in charge of the functions of metering, billing, and collections for its customers, the electric service accounts within the City. The MEU will have a Customer Services Division.
- The MEU's electric rates will be approved by the City Council or another governing authority, in a publicly transparent process. MEUs typically prepare their rate proposals within a dedicated independent Regulatory and Compliance Division, which interfaces with the balance of the MEU in producing the GRCs.
- The MEU will be subject to NERC compliance and the CPUC's General Orders (G.O.s) that apply to all utilities regardless of ownership or shareholder structure. NERC internal auditing and filing is anticipated to be completed by an independent division—the Regulatory and Compliance Division.
- The MEU will take electric power delivery at substations at the City's borders or at the first substations outside the City. The MEU will operate the transmission system inside the City and may have assets outside the City. It will also coordinate operations with CAISO and SDG&E and will remain inside CAISO as the Balancing Authority.

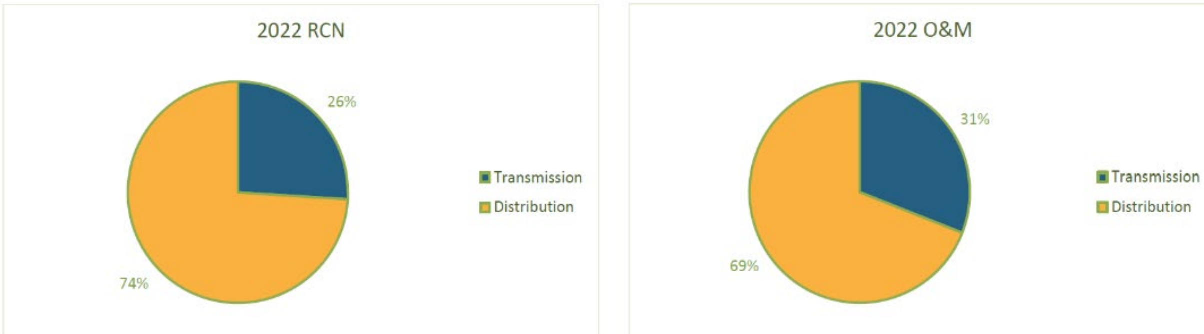


Figure 4-1. Transmission and Distribution RCN and O&M Cost Proportions

Figure 4-2 provides an overview of a potential organizational chart for the MEU from the General Manager level and below, referred to as Divisions and Departments for this report. The City management structure above the General Manager will vary depending on the organizational selected; it could be the Department of the City, a Separate Board, a Special District, etc. (as described in Section 3). The titles used in this report are only indicative of organizational ranking and may vary with the development of the MEU

General Manager's Office

The General Manager (GM) and the GM's office normally report to the City Chief Operating Officer (COO) if the organizational structure is a Department or to a Board under other organizations.

The GM and the GM's office would provide guidance to the MEU Division heads and would perform the following in coordination with them: set strategic goals and performance metrics; approve budgets and rate proposals; handle personnel matters; set operations and reliability goals; and communicate policies of interests to the Mayor and City Council as directed by the City's COO or the Board. Depending on the delegation of authority, including the duration and/or the dollar value of contracts, some actions of the MEU may escalate to the Mayor and/or City Council or the Elected Board for approval or decision making. Based on the size and complexity of the MEU, the GM's Office is assumed to have approximately 10 full time employees (FTEs).

General Counsel

The General Counsel would provide the MEU guidance and oversight on procurement, personnel claims, real estate matters, regulatory and environmental compliance, and civil claims and losses, and represents the legal interests of the MEU. As a City Department or Electric Board, the General Counsel could be a shared service as part of the City Attorney's Office (as discussed in Section 3). The General Counsel would be expected to report directly to the Board or City Council. The General Counsel's Office for this size utility would normally be expected to have approximately 25 FTEs.

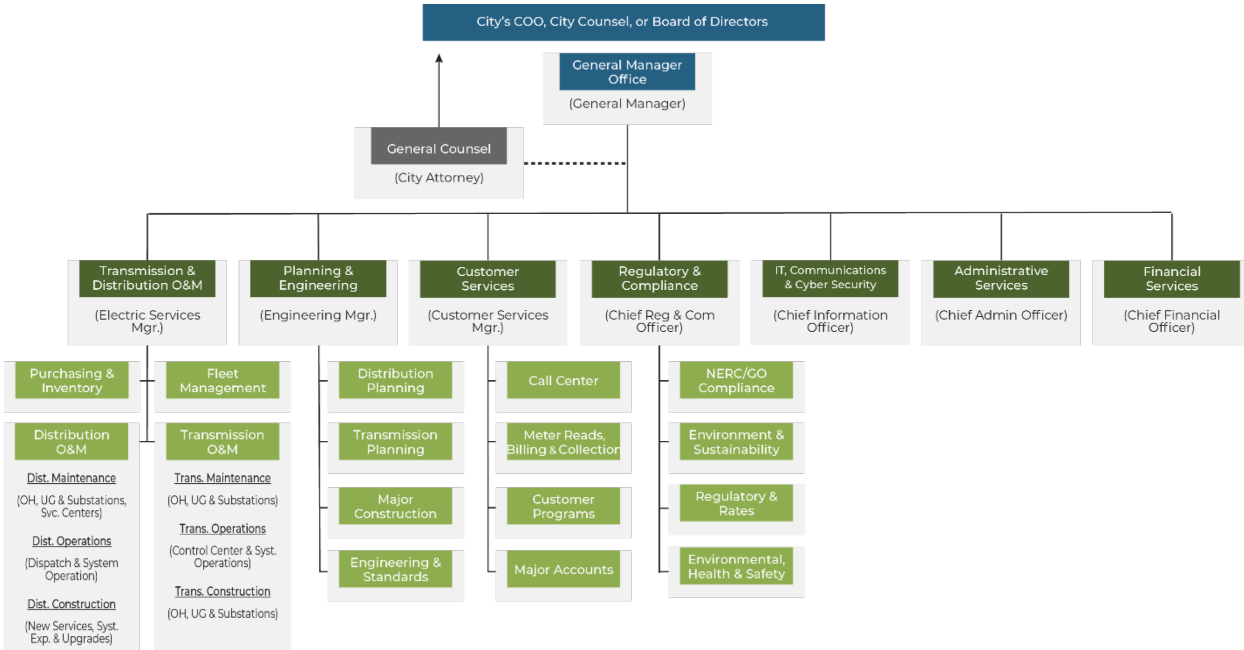


Figure 4-2. Example Organizational Chart

Transmission and Distribution Operations & Maintenance

Under the Electric Services Manager, this Transmission and Distribution O&M Division would operate, maintain, and build the transmission and distribution system, excepting major construction, which is typically conducted under the Engineering & Planning Division. The T&D O&M Division would be responsible for ensuring that the system is built, operated, inspected, and maintained in accordance with the NERC and the G.O. issued by the California CPUC (see the section on NERC and CPUC G.O. Standards).

The Central Office for this division would maintain and track all system records and provide compliance and reliability reports. This division is typically organized into two main departments within the utility: the Transmission O&M Department and the Distribution O&M Department. Additionally, this division would be expected to have two supporting departments: one for Fleet Management and one for Purchasing and Inventory.

Distribution Operations & Maintenance

The Distribution O&M Department would patrol, inspect, and maintain the overhead and underground power distribution assets and would operate and maintain the distribution switching stations and equipment (those at medium voltage, i.e., 12 kilovolts [kV], and transformers to transmission voltages at 69 and 138 kV).

The Distribution O&M Department would run a 24/7 operations/trouble center (Distribution Control Center or DCC) for system monitoring and remote operations, and to respond to system outages/disturbances. The Distribution Control Center would be staffed with active and standby personnel and there would be a primary and a backup location in the City. The DCC would direct and coordinate with field crews for maintenance switching of equipment, fault isolation switching, and service restoration.

The DCC would typically have the following systems integrated within its GIS and SCADA:

- **Distribution Energy Management System (DEMS):** This would control system condition awareness and remote switching. It would also provide the core functionality for the management of system operations at the MEU. Applications include telemetry, monitoring and alarming, distribution network analysis, distribution network optimization, and a Historical Information System.
- **Outage Management System (OMS)**: This would identify sections of the system without power based on AMI information and calls to the Call Center. It would also provide information on possible locations of faulted elements.
- **Workforce Management System (WMS)**: This would consist of applications that support the MEU management, scheduling, and dispatching of crews. The WMS would provide databases, tools, and applications that are used to plan, open, and close service restoration work, maintenance work, and/or construction work. WMS would include crew management modules that are used to assign personnel to crews and schedule crews to work. Work scheduling and dispatching is the subsystem for assigning crews to work and tracking completed and remaining work. WMS would also track the allocation and scheduling of MEU vehicles: cars, line trucks, earthmovers, cranes, and other equipment. The WMS system would also support material requisition and permit management.

The Distribution O&M Division would typically handle new business connections, vegetation management, G.O. inspections and compliance, repairs, upgrades (poles, cables, transformers, crossarms, etc.), overhead to underground conversions, field safety, training, and wildfire mitigation. It would likely contract with external suppliers for functions such as vegetation management and special/larger new construction. Major distribution construction would be managed outside this department, under the Planning and Engineering Department.

It is assumed that, given the size of the MEU, this could require three Service Centers located in the City. The Service Centers would serve as inventory warehouses, parking of fleet, and crew coordination and dispatch centers.

The Inspection and Maintenance functions would be carried out within the **Asset Management System** (AMS). This AMS would be a central repository of all the MEU's assets, including work history and a condition-based prioritized maintenance inspection schedule. The AMS would allow the MEU to gain maximum value from its physical asset base by balancing the operational performance of the asset against the asset life-cycle.

Transmission Operation & Maintenance

The Transmission O&M Department would patrol, inspect, and maintain the overhead and underground transmission assets, and would operate and maintain the high voltage transmission receiving and transmission switching stations. It would also need to follow the applicable NERC standards and CPUC's G.O.

Transmission would have a 24/7 operations/trouble center (Transmission Control Center or TCC) that would perform similar functions for system operations as the DCC and could be co-located. The TCC would be staffed with active and standby personnel and would require primary and backup locations. The TCC would operate under the direction of CAISO as the independent system operator and would coordinate switching of the multiple expected interconnection points with SDG&E. The TCC would also coordinate with field crews for maintenance and repair and would perform the required switching of the internal transmission system in coordination with CAISO and SDG&E if required.

The main software tool for the TCC would be the **Energy Management System** (EMS) integrated with the GIS and SCADA. The EMS would provide the core functionality for the management of the transmission system operations at the MEU. Applications for the EMS include telemetry, remote switching, monitoring and alarming, contingency analysis/network analysis, and a Historical Information System. Transmission would also utilize the same WMS and AMS as the distribution O&M function for patrolling, inspecting, and maintaining the transmission assets. Transmission would likely contract with external suppliers for new construction, but major transmission construction would likely be managed by the Planning and Engineering Division.

Fleet Management

The Fleet Management Department would oversee fleet performance, maintenance, utilization, expenses, and users to ensure that the organization has access to a reliable fleet of the necessary vehicles and equipment at a reasonable cost.

The fleet of specialty electric utility vehicles necessary for the MEU would likely include the following:

- Line Trucks – for distribution and streetlight O&M and construction activities.
- Bucket Trucks – for overhead streetlight and O&M and construction activities.
- Digger Derricks – for pole installations.
- Backhoes and other construction equipment.
- A range of trailers capable of transporting reels of conductors, transformers, power and streetlight poles, switchgear cabinets, and other large and heavy equipment and materials.

Purchasing and Inventory

The Purchasing and Inventory Department would be responsible for procurement of equipment, materials, and services ranging from selecting vendors to placing orders and making payments for goods received. The inventory function would include assisting engineering and field crews with specifying needed materials and equipment, receiving, issuing inventory items, and monitoring inventory levels to ensure materials are replenished as needed.

The specifications for materials and equipment would be determined by the Planning and Engineering Division, and the Purchasing and Inventory Department would place material requisitions using these standards and following requests that are generated in the AMS. Material requisitions would be forwarded electronically to the Finance Group where they would be reviewed relative to budgets and funding and would be followed by purchase orders (POs).

Staffing

The Transmission & Distribution O&M Division would be the largest division within the MEU, with an estimated 900 FTE across all functions.

The three service centers are expected to have 225 FTE each (675 FTE total). Operations would have approximately 75 FTE for T&D, and the balance of the organization including the central office of the Electrical Service Manager would have approximately 150 FTE.

Planning and Engineering

Under the Engineering Manager, the Planning and Engineering Division would typically provide engineering services for all aspects of the transmission and distribution business, including planning, overhead to underground conversions, substations designs, relay protection and controls, design standards, specifications, contracts, meters and smart grid design, new business design and utility relocations, and general facility design.

Other engineering functions would include real estate and right of ways for power system land requirements, drafting, maps, and records management. Specialty type engineering would include construction contracts, project management, and contract administration. Chemistry and test lab functions would include oil, gas, and hazardous material testing; glove testing; meter and relay testing and calibration; transformer testing; and facility commissioning. Some unique power engineering would include emerging technologies and research and development functions. This Division would be organized into four departments in charge of Distribution Planning, Transmission Planning, Major Construction, and Engineering & Standards.

Distribution Planning

The Distribution Planning Department would be responsible for identifying needs and designing the distribution assets required to maintain a reliable distribution system in the short, medium, and long term. In the short term, distribution planning identifies weakness, reliability violations, and/or quality of service issues, and is responsive to customers and requests (e.g., new service connections and Distributed Energy Resources [DER] interconnection requests). In the medium and long term, this department would plan for future needs as identified by the load growth forecast (including electrification and electric vehicles [EV] loads), DER forecast, and aging infrastructure. Based on the above, the Distribution Planning Department would be responsible for the development of the Distribution Capital Improvement Program.

Distribution Planning would coordinate with the Distribution O&M Department to maintain a current understanding of the short-term distribution system conditions and needs as well as the network upgrades or changes made to the network. Distribution Planning would also be responsible for the system design to ensure that there is compliance with the MEU's planning criteria, i.e., reliability (SAIFI, CAIDI), voltage regulation (American National Standard Institute [ANSI] C84.1 standard), preferred loadings (minimum loading upon installation, long-term loading, allowable overloading), and the applicable CPUC general orders (see the section NERC and CPUC G.O. Standards).

One of the central challenges for the Distribution Planning Department would be to design a system that can reliably supply the expected large load increases due to the dual impact of EV charging and building electrification. Both of these loads are likely to peak in the evening given current electrical rate structures, while DER generally peaks during daytime, stressing the distribution system. Distribution Planning is expected to anticipate these needs and address them via a combination of: a) load management at the customer level (demand response), b) Storage deployed as a Distribution Asset (Non-Wires Alternatives), and c) investments in the distribution network.

Distribution Planning would maintain the following tools:

- **Distribution Model:** Consists of Base Case models for short term (years 1 to 5), medium term (typically year 10), and long (year 15 and 20) terms. Cases are developed and maintained considering the DER and demand forecasts as well as committed investments in electrification. The model would be geographically accurate and closely coordinated with the GIS model of the distribution system.

- **Load Forecast Model:** Provides geolocated forecast for the gross customer load and its modifiers: Energy Efficiency, EV Charging, Building Electrification, and DER.
- **Estimating Program:** Used to price the various expansion options and select the least cost option.

Transmission Planning

The Transmission Planning Division would be responsible for identifying and designing a reliable transmission system over the short, medium, and long term periods to deliver power from generating resources to the transmission systems, distribution substations, and loads directly connected to transmission, as well as to reliably support transfers across the MEU as directed by CAISO.

The Transmission Planning Department would coordinate with the Distribution Planning Department, the Transmission O&M Department, CAISO, Western Electric Coordinating Council (WECC), and neighboring transmission owners (SDG&E) to ensure coordinated planning of the system. Transmission Planning would be responsible for the system design to ensure that it complies with its planning criteria, NERC requirements (see the section NERC and CPUC G.O. Compliance), and CAISO specific criteria. It would be in charge of conducting the generation interconnection studies for the transmission system as well as those for large loads.

Transmission Planning would maintain the following tools:

- **Transmission Model:** CAISO and WECC maintain these models in PSLF and PSS®E, and the main role of the transmission providers (i.e., the MEU) is to provide updates that reflect system additions and the load forecast for the development of the systemwide models.
- **Load Forecast Model:** This would provide the substation-level forecast for the gross customer load and its modifiers: Energy Efficiency, EV Charging, Building Electrification, and DER.
- **Estimating Program:** This would be used to price the various expansion options and select the least cost option.

Major Construction

The Major Construction Department would typically be in charge of the project management of major capital projects. Once a large capital project is identified by Transmission or Distribution Planning Divisions and obtains the initial internal approvals, the responsibility of the project would be transferred to Major Construction for engineering and construction. Upon commercial operation, these major projects would then be handed to the Transmission & Distribution O&M Division for operation.

Major Construction would serve as the lead for developing the preliminary engineering design (referred to as 35% design) in order to specify and solicit a contract for final engineering procurement and construction (EPC). The development of the projects to the 35% design stage would rely on the support of engineering firms selected and managed by the Major Construction staff. The Transmission or Distribution Planning management and staff would provide continuous review and guidance to the projects through the 35% design and the EPC stage. Major Construction would have a procurement function which would be primarily focused on requisitioning professional services and construction and EPC agreements. Similar to the process used for purchasing equipment and materials initiated by Purchasing and Inventory Division, requisitions for procurement would be forwarded by Major Construction to the Finance Group to issue the POs and render vendor payments.

Engineering & Standards

The Engineering and Standards department would be in charge of producing the final design, drawings, and specifications and budgets for all construction identified by T&D planning that does not fall into the Major Construction category above, which are typically special one-time projects.

Engineering and Standards would prepare budgets and special requests for larger expenditures to the Finance Group and would produce work orders under assigned budgets approved. This department would also participate in the commissioning and acceptance test of all equipment and maintain up-to-date records and the GIS with as-built information.

The Engineering and Standards Department would typically produce specifications and designs for protection and control systems and devices, smart grid (e.g., feeder automation), and smart meters and AMI, and would conduct emerging technologies and research and development functions (unless these functions were already covered in Planning). In support of new construction, Engineering & Standards would have units in charge of Real Estate (right of ways and easements) and test labs in support of maintenance.

This department would also have the function to produce and maintain the engineering standards needed by the MEU for construction and engineering of new and existing electric transmission and distribution systems in the City. It is expected that the MEU will initially adopt the same comprehensive engineering standards used by SDG&E.[5] However, over time and in response to the large changes expected in the industry and the specific needs and policies of the City, the MEU will have to develop its own standards, potentially coordinating with SDG&E given the level of interconnection between the two. This would align the MEU with most utilities that dedicate significant staff resources to developing and maintaining engineering standards based on the specific characteristics of their electrical system, atmospheric conditions, and policies.

Staffing

The Planning and Engineering Division is expected to have an estimated total of approximately 240 FTE, divided as follows: 26 FTE for the two planning divisions (T&D) combined, 178 FTE for Engineering & Standards, and 28 FTE for Major Construction. The balance of 8 FTE will be at the division management level.

Customer Services

Under the Customer Services Manager, the Customer Services Division would provide the 24/7 customer Call Centers, Customer Service Centers, Accounts Receivables & Collections, Marketing, and Customer Programs (Demand Response, Energy Efficiency, Electric Vehicle Chargers, Rebates, Incentives [Solar, Batteries, Lighting], Public Purpose Program Funds, CARE, Med baseline, and others), and Beyond the Meter Services).

Customer Services would track customer usage and provide load forecasting, large customer (Commercial and Industrial) relations, and customer communications. This division would also include the meter reading function and meter setters along with turn on/turn off services.

The division would be organized into the following departments: Call Center, Meter Reads Billing & Collection, Customer Programs, and Major Accounts.

---

[5] https://www.sdge.com/project-resources

Call Center

The 24/7 Call Center would be the main interface between the MEU and its customers. It would typically be supported by both an Interactive Voice Recognition System (IVR) and live operators.

The IVR system would provide calling customers with information on ongoing outages in the system and the expected restoration times. It would also collect preliminary information on the nature of the call (no-lights/trouble, billing, new accounts, etc.) and provide responses and further routing to an operator, if required. The IVR can put out outgoing calls as needed to inform customers of an ongoing or expected outage and restoration times (via voice or SMS messaging). The Call Center would also communicate with customers via other sources including postal services, web and web chat, and email.

Once a call is routed, operators would collect customer information including name and address (if not available from the caller ID) and a balance of the information, e.g., customer number, legal address, GIS location, etc. from the Customer Identification System. They would also determine the nature of the incident (no lights, low voltage, flicker, etc.). As an example, operators would enter “No Lights” for a specific customer on the Outage Management System. Outage Management would detect that calls may have a common cause and narrow down the affected area. The Outage Management System would inform the operator if it were an ongoing event already reported (and restoration time if available) or record it as new event and communicate it to Distribution Operations Division.

The Call Center would be located within the City and owned and operated by the MEU for day-to-day operations and should have a contracted overflow procedure to be used during emergencies.

Meter Reads, Billing, & Collections

The Meter Reads, Billing, and Collections Department would be responsible for meter reading, development of customer bills, and revenue collections. Metering would be carried out via the Automated Meter Reading system (also known as Advanced Metering Infrastructure—AMI). It would consist of a set of applications and infrastructure components for collection, validation, analysis, and delivery of metering data to back-office applications. At a high level this would include metrology and communications, the Head-End application for collection, and the meter data management systems (MDMS). Specific tools required for this department would include the following:

- Metrology and Communications would cover specific hardware and software requirements required from the perspective of the overall AMI system.
- The Head-End application would be responsible for data collection, 2-way communication, and control functions for all meters that are part of the metering network. The system would also be responsible for managing the network and security of all devices that are part of the metering network.
- The MDMS would be responsible for consolidation of meter data and validation, editing, and estimation of meter readings. The MDMS would also typically be the system of record for meter data and would integrate with upstream applications such as the Customer Information System and Billing to provide rate-ready meter data or bill-ready data to the billing engine. It would also provide support for customer service representatives, customer bill inquiries, real-time customer support via phone, email, and enhanced customer support and information, and would provide analytics on consumption and deviations (possible tampering).

Billing would be conducted using the Billing Systems that include application functionality to compute and produce bills for each customer’s account. Billing Systems typically interface with the MDMS to read data files for computing the customer's bill according to the tariff (billing determinants). The billing calculations may require different data depending on the customer class and rate design such as:

- Total Energy used
- Energy used during peak hours
- Energy used during non-peak hours
- Maximum Demand during billing period
- Allocation of energy used for street lighting
- Service charges
- Work requests
- Taxes
- Interest on Arrears
- Credits
- Fines
- Social program allocations

This system would have functionality to set up and maintain the tariff structure for billing calculations. A history of tariff structure changes may also be supported to allow reruns of previously issued bills with a new tariff structure. Billing systems typically also include records of customer payments, time of payments, payment arrears, payment plans for arrears, etc. This last functionality would be used for the collections functionality of this department.

This department would also be in charge of customer connection and disconnections via the two-way AMI. Connection/Disconnection may be made due to a number of business reasons including nonpayment of arrears, start/end of service, and change of address.

Customer Programs

Customer Programs would design, budget, and administer MEU's programs designed to incentivize customer participation in programs aligned with the City's goals and objectives. These programs would include Energy Efficiency programs (e.g., efficient appliances, HVAC and lighting, weatherization of buildings/new standards, etc.) for residential and commercial customers, demand response & remote control of loads (via AMI) programs, Electric Vehicle chargers deployment, building electrification programs, and incentives for customer-owned photovoltaics (PV) and storage (DER).

This department would require a specialized team of professionals that identify the programs to be implemented over the short, medium, and long term. The department would work in close collaboration with the Distribution Planning Department.

Once a program is identified, Customer Programs would be responsible for the preparation of the required funding from the MEU.

Major Accounts

Utilities typically have a dedicated group within their organization that focuses on the interaction with the largest existing and potential customers, i.e., their major accounts. The MEU's Major Accounts

Department would take this functionality and become the single point of contact for large commercial and industrial customers as well as generating facilities interconnecting to the MEU's transmission network.

The Major Accounts department would perform the account setup, customer onboarding, and general account management for these large customers. It would also interface with other departments inside the MEU to address requests and concerns brought by its customers, such as billing/metering issues with the Meter Reads Billing & Collection department, requests for additional services with the Planning and Engineering Division, quality of supply (interruptions, flicker, low/high voltage, etc.) with Operations, etc.

The department would also provide information marketing and business development functions to reach out to new prospective customers and inform existing customers of the various programs and other rate offerings available.

Staffing

The Customer Services Division is expected to have an estimated total of 320 FTE, divided as follows: 8 FTE for the division level, 200 FTE for the Call Center, 60 FTE for Meter Reads Billing & Collection, 30 FTE for Customer Programs, and 22 FTE for Major Accounts.

Regulatory & Compliance

The Chief Regulatory and Compliance Officer would lead this division and would collaborate with, collect information from, and audit compliance of other divisions inside the organization.

The division would be expected to be organized into the following departments: NERC/G.O. Compliance, Environment & Sustainability, Regulatory & Rates and Environmental, and Health and Safety.

NERC/G.O. Compliance

The NERC/G.O. Compliance department would work with the different divisions and departments of the MEU to prepare the NERC compliance reports to be sent to WECC, perform internal audits on compliance, and participate and become the first point of contact for the periodic audits conducted by WECC. The NERC standards applicable to the MEU are multiple and diverse as discussed herein.

This department would work with the distribution planning and distribution O&M divisions to ensure compliance with the CPUC's G.O. directives.

Environment & Sustainability

The Environment and Sustainability Department would collaborate with other internal and external organizations, and develop and track progress of environmental initiatives, strategies, and sustainability programs. This department would also prepare jurisdictional agency filings, environmental impact reports, and regulatory compliance reports in accordance with the California Environmental Quality Act (CEQA).

This department would have extensive procedures to follow for interacting with construction, maintenance, and operations. It would be responsible for obtaining construction permits for the capital projects which require environmental management. After construction is complete, the department would continue to be responsible for ongoing permit requirements and reporting.

Regulatory & Rates

The Regulatory and Rates Department's core function would be to develop rate proposals to be presented to the City for approval based on the MEU's financial plans and projections. The department would coordinate across the MEU on financial forecasting, cost of service analysis and management, and rate development. Their primary functions would include the following:

- Analyze current and forecasted capital, operating, and administrative and general (A&G) expenditures and customer base change.
- Perform a cost of service (COS) study on a regular basis, either directly or via an outside consultant.
- Analyze and review current rates and prepare rate proposals for the MEU to meet its financial obligations, especially on debt service.
- Provide technical rate studies and information to the MEU's management and to the City to support the formulation of policy direction and guidance on the rate-setting process.

For regulatory and legislative compliance, the department would be responsible for identifying, assessing, monitoring, and selectively participating in regulatory and legislative activities that potentially impact the MEU. The department would also carry out the responsibility of communicating their findings to the different MEU teams that would be potentially impacted by the proceedings and activities. The department would be responsible for monitoring proceedings and activities at FERC, the CPUC, the California Energy Commission (CEC), and the state legislature. Their activities would likely be assisted by law firms and the City Attorney's Office. A key function of this department would be prioritizing the numerous regulatory and legislative activities that could potentially impact the MEU. This prioritization is not only necessary to plan and manage the allocation of staff time, but also to assist the MEU in participating in and planning for those regulatory and legislative activities that have the greatest potential impact to operations.

Environmental, Health, and Safety

The Environmental, Health, and Safety (EHS) Department would be expected to interact with multiple departments within the MEU in discharging its functions and leading the development of an Emergency Preparedness Plan.

Providing electric service is an inherently hazardous activity. The EHS department would ensure that when performing these activities, the most stringent conditions specified by the federal government in the U. S. Code of Federal Regulations (CFR), the California Health and Safety Code, the California Code of Regulations (CCR), and local governmental units are met as a minimum. This department would also ensure that the exposure of employees to hazardous materials and the way materials are stored and used are compliant with the applicable government regulations. The emergency planning function of the department would include ensuring emergency response readiness across the organization. It would also include updating various plans, conducting trainings and exercises, creating mass notification protocols, and serving as a liaison between the MEU, the City, and regional emergency response partners. The MEU would be expected to participate in various exercises or drills on a local and regional level, most of which have a first responder component.

Staffing

The Regulatory & Compliance division has an estimated 60 FTE: 8 FTE for NERC/G.O. Compliance, 18 FTE for Environment & Sustainability, 18 FTE for Regulatory & Rates, and 12 FTE for Environmental, Health and Safety. 8 FTE are expected to be at the management level.

IT, Communications, & Cyber Security

Under the direction of the Chief Information Officer, the IT, Communications, and Cyber Security Division would support the systemwide enterprise applications such as Customer Information Systems, payroll, personnel, financial reporting, work management, records management, and asset and facility management applications. IT would support network operations and various telecommunication technologies (phones, radios, fiber, etc.) and a 24/7 network operations center (NOC).

IT applications would be fundamental to most functions within the MEU including the business-critical functions associated with operations and billing. This department's primary focus would be on system availability, service, and project delivery. The division would be responsible for implementing cybersecurity at the utility level and ensuring compliance with the NERC CIP standards (see NERC and CPUC G.O. Standards section). Finally, IT would be responsible for the server infrastructure to run the MEU's various applications.

Staffing

The IT, Communications, & Cyber Security has an estimated 145 FTEs: 100 supporting Enterprise-Wide Apps (CIS, Payroll, Financials, Work Management, Personnel, AM/FM systems); 40 for Network Operations, Telecoms – Phones, Radio, Fiber (24/7 NOC); and 5 at the IT management office.

Human Resources and Administrative Services

The Chief HR Officer would be in charge of the Human Resources and Administrative Services Division. This division would coordinate the following functions:

- Employee Health & Safety
- Equal Employment Opportunity Programs & Americans with Disabilities Act/Fair Employment and Housing Act Programs
- Payroll
- HR Analytics
- Employee & Labor Relations and Return to Work Programs
- Workforce Planning
- Learning & Development
- Talent Acquisition
- Employment Life Cycle

This division would prepare budgets for approval by the Finance Group and sign employment/collective bargaining contracts when applicable. The division would also be in charge of corporate communications and the Security Services (24/7) and Custodial services function.

Staffing

The Human Resources and Administrative Services Division is expected to have 240 FTE, 50 for the HR function, 8 for corporate communications, 140 for the Security Services and Custodial Services, and 6 at the division head level.

Financial Services

Under the Chief Financial Officer, this Division (the Finance Group) would provide and coordinate all the financial accounting and reporting including budgets and expenditures, debt service and bond issuance, risk management (insurance), payroll, retirement, rates, and rate cases.

This division, with the support of the requesting entity, would be responsible for bringing the approval of budgets and capital expenditures to the Board and the General Manager.

Staffing

The Financial Services Division is expected to have 220 FTE.

Total MEU Estimated Staffing Requirements

Based on the estimates above for each of the divisions, the EMU is expected to require approximately 2,160 FTE, as shown in Table 4-1.

Table 4-1
Staffing Requirements

Division	FTE
General Management	10
General Counsel	25
Transmission & Distribution O&M	900
Planning and Engineering	240
Customer Services	320
Regulatory & Compliance	60
IT, Communications, & Cyber Security	145
Human Resources and Administrative Services	240
Financial Services	220
Total	**2,160**

NERC and CPUC G.O. Standards

The MEU, as a wires-only utility without generation, would be expected to be registered with NERC under the following categories:

- DP- Distribution Provider: The entity that provides and operates the “wires” between the transmission system and the end-use customer, independent of voltage.

- TO- Transmission Owner: The entity that owns and maintains transmission facilities.
- TOP- Transmission Operator: The entity responsible for the reliability of its local transmission system and that operates or directs the operations of the transmission facilities.
- TP- Transmission Planner: The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.
- TSP- Transmission Service Provider unless provided by CAISO (SDG&E is not a TSP but the following California utilities are: LADWP, SMUD, Imperial Irrigation District, and Turlock Irrigation District).

Therefore, the MEU would be subject to NERC standards and compliance including the standards presented below.

Cybersecurity

Cybersecurity standards are applicable to the Bulk Electric System (BES) and must be adhered to by all departments of the MEU. These standards are listed in Appendix A, Table A-1.

Transmission Operations

These NERC Operation standards basically fall under the responsibility of CAISO as the system operator, but the MEU will be required to comply and support CAISO. These standards are listed in Appendix A, Table A-2.

Transmission Owner

The MEU will be a transmission owner (TO) and therefore subject to the standards listed in Appendix A, Table A-3.

Transmission Planning and Engineering

The MEU's transmission engineering and planning function, including transmission operations planning, will be subject to the standards listed in Appendix A, Table A-4.

Other NERC Standards

In addition to the standards referenced in Appendix A, there are specific standards applicable to the Transmission Owner on system protection maintenance, performance, and testing (PRC-005-x, PRC-023-4, PRC-026-1, and PRC-027-1); underfrequency load shedding protection (PRC-006-x and PRC-008-0); under voltage load shedding (PRC- 010-2 and PRC-011-0); and Remedial Action Schemes (PRC-012-2, PRC-017-1). There are also standards on communication capabilities and protocols (COM-001-3 and COM-002-4) and personnel training (PER-003-2 and PER-006-1).

Distribution Standards

Most of the NERC standards above apply to the transmission systems; however, for the distribution system there are the General Orders (G.O.) issued by the CPUC. These orders are very detailed and include:

- G.O. 95: Overhead electric line construction.

- G.O. 128: Construction of underground electric supply and communication systems
- G.O. 128: Rules for Construction of underground electric supply and communication systems
- G.O. 166: Standards for Operation, Reliability, and Safety During Emergencies and Disasters
- G.O. 174: Rules for Electric Utility Substations

Risk Management

Risk Management would be a distributed function for the MEU that would be expected to be under the supervision of the General Manager's office. As a wires only company, the MEU's main areas of risk would include operational risks and liabilities and credit risks. On the operations side, these would be partly managed with the emergency response plans and stakeholder engagement, and partly with adequate systems, equipment, and liability insurance.

Credit risks would be managed by credit policy and implementation supported by cash management and debt coverage adequacy within the Financial Services Division.

Projected Annual Costs

To estimate the operating costs for the MEU, the NewGen Team utilized the costs reported by SDG&E under FERC Form 1 for Transmission Operation & Maintenance, Distribution Operation & Maintenance, Customer Accounts, and A&G for 2020. The NewGen Team estimated the corresponding costs of the MEU considering the proportions (ratios) of the RCN of the assets that would form the MEU to the total assets currently owned by SDG&E.

The MEU's fraction of SDG&E's total O&M costs was estimated considering the RCN of the assets as detailed in Tables 4-2 through 4-5 below (see Section 5 for the development of the RCN value). The cost element considered is in the left column and the ratio of the assets' RCN used for the estimation of their respective annual costs is in the right column.

Table 4-2
Transmission Operations

Cost Element	RCN Ratios MEU/SDG&E
System Operation	All Transmission Assets RCN
System Planning	All Transmission Assets RCN
Overhead Lines Expenses	Lines RCN
Underground Lines Expenses	Lines RCN
Substations HV Expenses	Substations RCN
Other	All Transmission Assets RCN

Table 4-3
Transmission Maintenance

Cost Element	RCN Ratios MEU/SDG&E
Supervision & Engineering	All Transmission Assets RCN
Overhead Maintenance	Lines RCN
Underground Maintenance	Lines RCN
Substations HV Maintenance	Substations RCN
Other	All Transmission Assets RCN

Table 4-4
Distribution Operations

Cost Element	RCN Ratios MEU/SDG&E
System Operation	All Distribution Assets RCN
Overhead Expenses	Overhead Lines RCN
Underground Expenses	Underground Lines RCN
Substations Distribution (MV & HV/MV XMR)	Distribution Sub RCN
Transformers	Transformers RCN
Meters & Services Expenses	Meter & Services LV RCN
Streetlights Expenses	Streetlights RCN
Other Expenses	Other Assets RCN

Table 4-5
Distribution Maintenance

Cost Element	RCN Ratios MEU/SDG&E
Supervision & Engineering	All Distribution Assets RCN
Overhead Maintenance	Overhead Lines RCN
Underground Maintenance	Underground Lines RCN
Substations Distribution (MV & HV/MV XMR) Maintenance	Distribution Sub RCN
Transformers Maintenance	Transformers RCN
Meters & Services Maintenance	Meter & Services LV RCN
Streetlights Maintenance	Streetlights RCN
Other Maintenance	Other Assets RCN

Customer service costs were allocated considering the ratios of the number of customers (MEU to SDG&E total) and the A&G as a proportion of the direct costs (O&M and customers).

Tables 4-6 through 4-9 present the projected 2022 costs for SDG&E and the MEU using the 2020 FERC Costs and the ratios of assets' RCN and customers (see section 5). Values provided below are in $000 and have been rounded to the hundred thousandths place in most cases. Therefore, totals may not add due to rounding.

Table 4-6
2022 Transmission O&M ($000)(1)

Transmission	SDG&E	MEU
Operations		
System Operation	$17,900	$2,200
Planning	$3,900	$500
Overhead	$11,100	$1,200
Underground	$40	$4
Substations HV	$7,900	$1,400
Other	$25,000	$3,100
Total Operations	$65,800	$8,500
Maintenance		
Supervision and Engineering	$5,900	$700
Overhead	$28,300	$3,200
Underground	$1,100	$100
Substations HV	$19,600	$3,400
Other	$200	$20
Total Maintenance	$55,200	$7,500
Total Transmission	$121,000	$15,900

(1) Totals may not add due to rounding.

Table 4-7
2022 Distribution O&M ($000)(1)

Distribution	SDG&E	MEU
Operations		
System Operation	$27,800	$8,900
Overhead	$11,300	$1,500
Underground	$6,600	$1,600
Substations Distribution (MV & HV/MV XMR)	$6,430	$3,590
Transformers	$0	$0
Meter & Services	$18,200	$8,500
Streetlights	$800	$0
Other	$57,400	$27,100
Total Operations	$128,600	$51,200
Maintenance		
Supervision & Engineering	$3,300	$1,100
Overhead	$114,800	$15,700
Underground	$16,500	$3,900
Substations Distribution (MV & HV/MV XMR)	$4,300	$2,400
Transformers	$100	$2,400
Meter & Services	$1,700	$100
Streetlights	$200	$800
Other	$3,900	$0
Total Maintenance		
Total Distribution	$273,500	$77,500

(1) Totals may not add due to rounding.

Table 4-8
2022 Metering Customers & Sales ($000)(1)

Metering, Customers & Sales	SDG&E	MEU
Metering & Collection	$98,800	$45,900
Customer Services	$155,200	$72,200
Total	$254,000	$118,100

(1) Totals may not add due to rounding.

Table 4-9
A&G & Total Cost ($000)(1)

A&G	SDG&E	MEU
A&G Total	$615,400	$200,800
Total Cost	$1,263,900	$412,400
$/Customer	***$841***	***$590***
$/MWh	***$74***	***$57***

(1) Totals may not add due to rounding.

As shown in this table, the O&M costs per customer for the MEU are expected to be substantially lower than those of SDG&E. This is due to two reasons: first, the MEU is expected to have fewer transmission assets than SDG&E (as shown in Section 5, the 2022 MEU transmission RCN per customer is much lower that the SDG&E transmission RCN per customer); and second, the MEU would have greater density than the balance of SDG&E and thus the length of underground lines per customer would be smaller, which results in a lower distribution RCN per customer for the MEU.

The NewGen Team projected the O&M cost considering the growth in invested assets (based on Reproduction Cost New [RCN]) presented in Section 7. The customer costs were projected considering the growth in customers and the A&G as a result of the increase in the two previous costs. Figures 4-3 and 4-4 below show the projected costs (in constant 2022$) and the total cost per customer (2022 dollars/Customer). There is an expected increase in the cost per customer starting from under $600/customer and reaching just under $700/customer by the end of the projection period (2042). This increase can be attributed to the fact that the invested assets per new customer are expected to be higher than the average cost per customer and this results in an increase in O&M costs per new customer higher than the average.

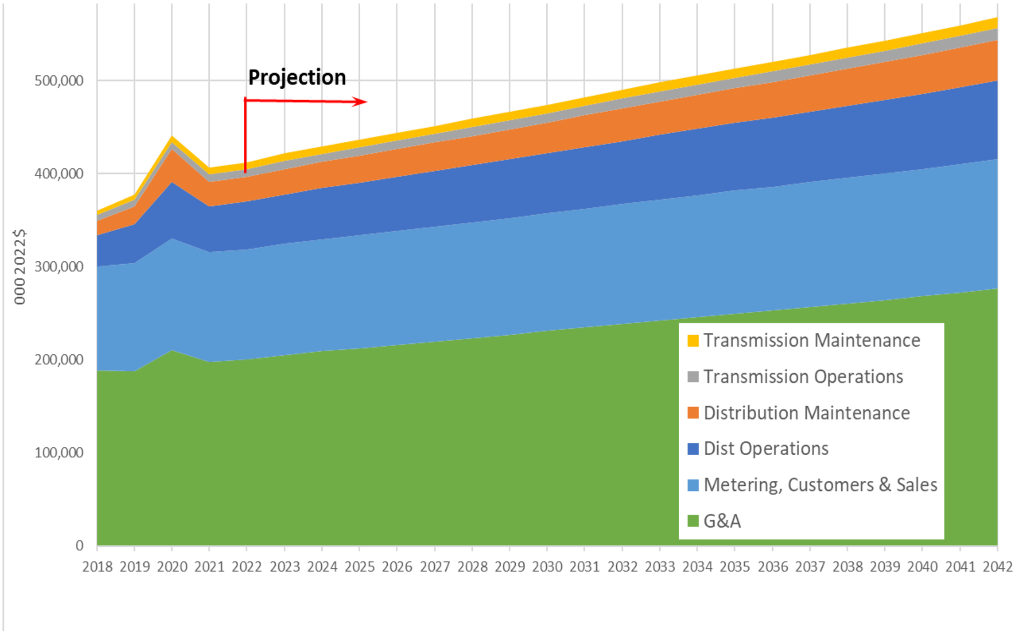


Figure 4-3. Projected Costs in 2002$

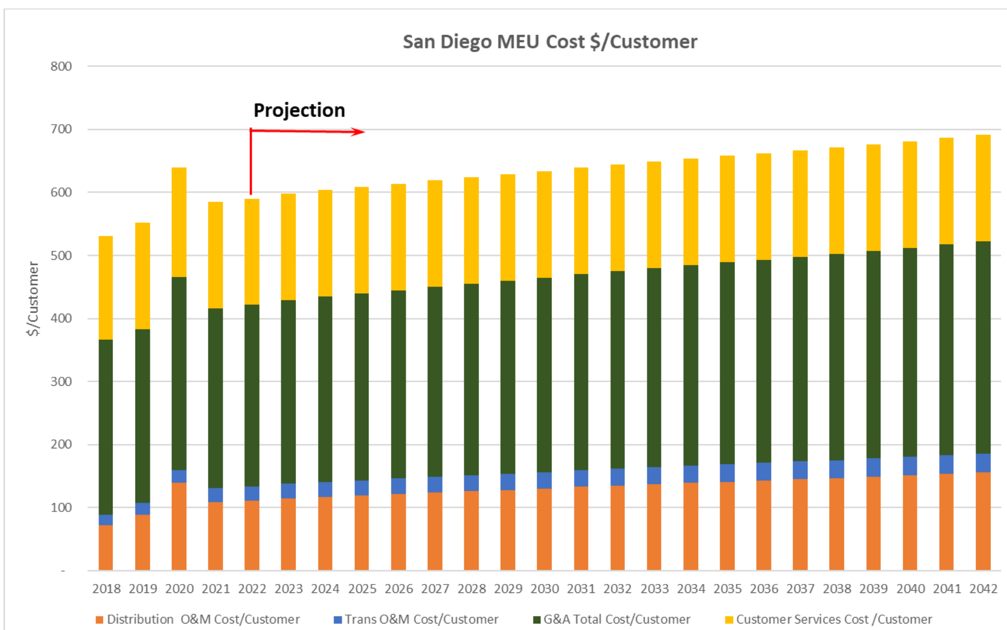


Figure 4-4. Projected Costs per Customer

Section 5
ACQUISITION COSTS (PRELIMINARY)

The MEU would be created by the acquisition of selected SDG&E transmission and distribution assets and would be a "wires only" entity that would provide electric transmission and distribution service to the customers inside the City.

Distribution service starts at high voltage (138 kV or 69 kV – HV) to medium voltage (12 kV or 4.16 kV – MV) transformers at the transmission to distribution substations. Then, via the MV equipment connecting these substations to the customers' locations, power is delivered to the distribution transformers, where it is lowered to low voltage (LV) and delivered to the customers with the LV equipment and meters.

Transmission systems consists of the 230 kV, 138 kV, and 69 kV transmission lines and substations where interconnection occurs between these voltages, switching occurs, and HV transformers exist. The substations also house the MV transformers which are considered part of the distribution system.

Figure 5-1 shows the transmission system substations by voltage inside the City and vicinity and Figure 5-2 shows the main transmission lines and 69 kV and above substations.

Key Considerations

The process of determining the estimated acquisition costs has two main steps: a) identify the assets to be acquired, i.e., the inventory; and b) determine the estimated cost of these assets.

With respect to distribution, the City will need to acquire all the assets inside the City up to the City's municipal border, where severance investments will be made to separate the City's customers from SDG&E (see Section 6).

For transmission, it is important to realize that these assets have two main functions. The first is to transport power from generation resources through the transmission system to distribution high voltage/medium voltage (HV/MV) substations, from which it is delivered to the load by the distribution system. The second function is to provide reliability, loss reduction, and flexibility of the supply of power to the load by supporting the distribution system through the interconnection of the HV/MV substations, thus creating alternative sources of supply and allowing power to flow more efficiently at the HV level.

Therefore, at minimum, it is recommended that the City acquire the 138 and 69 kV system inside the City including the substations and lines interconnecting the substations. This will allow the MEU to retain control of critical transmission assets and to co-optimize the operation and expansion of the combined T&D system. At the substations outside the City, where distribution feeders that supply load inside the City start (defined as the Border Substations), the MEU should at minimum acquire the HV/MV transformers and the MV equipment connecting the feeders that extend into the City. The HV transmission lines connecting the substations inside the City to other SDG&E substations, including the Border Substations, can remain with SDG&E under this minimum acquisition option. Alternatively, the Border Substations could be partially acquired, requiring severance investments at the HV level. In this scenario, the lines to SDG&E substations remain with SDG&E. Finally, the option for maximum independence would include the acquisition of these lines and the 230 kV system as well.

For this Phase I report, the NewGen Team used the minimum transmission acquisition option as a baseline for determining the MEU acquisition costs. Further assessment of the tradeoffs between flexibility and costs of the other acquisition options may be completed in the future if the City moves forward with development of the MEU.

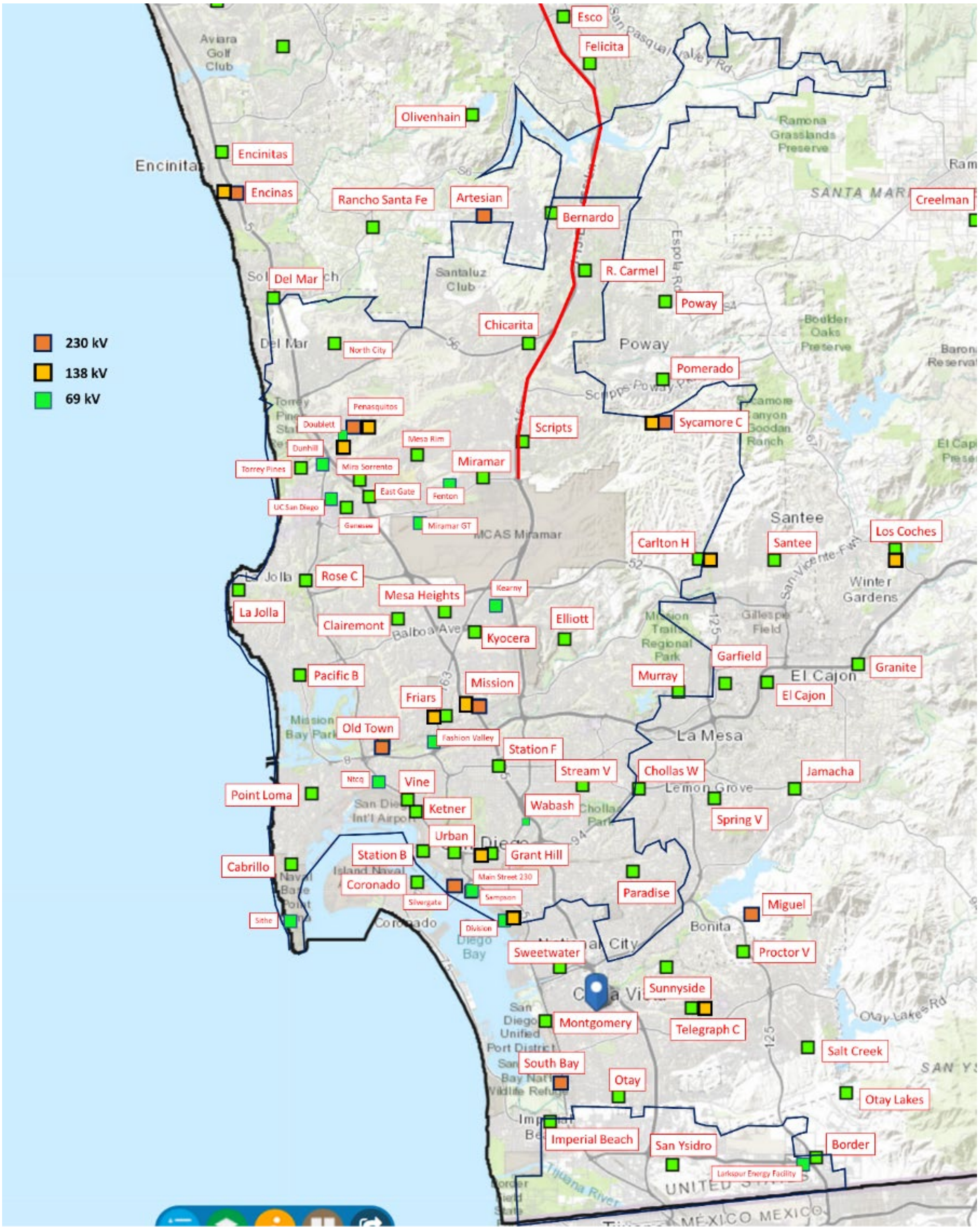


Figure 5-1. Transmission Substations

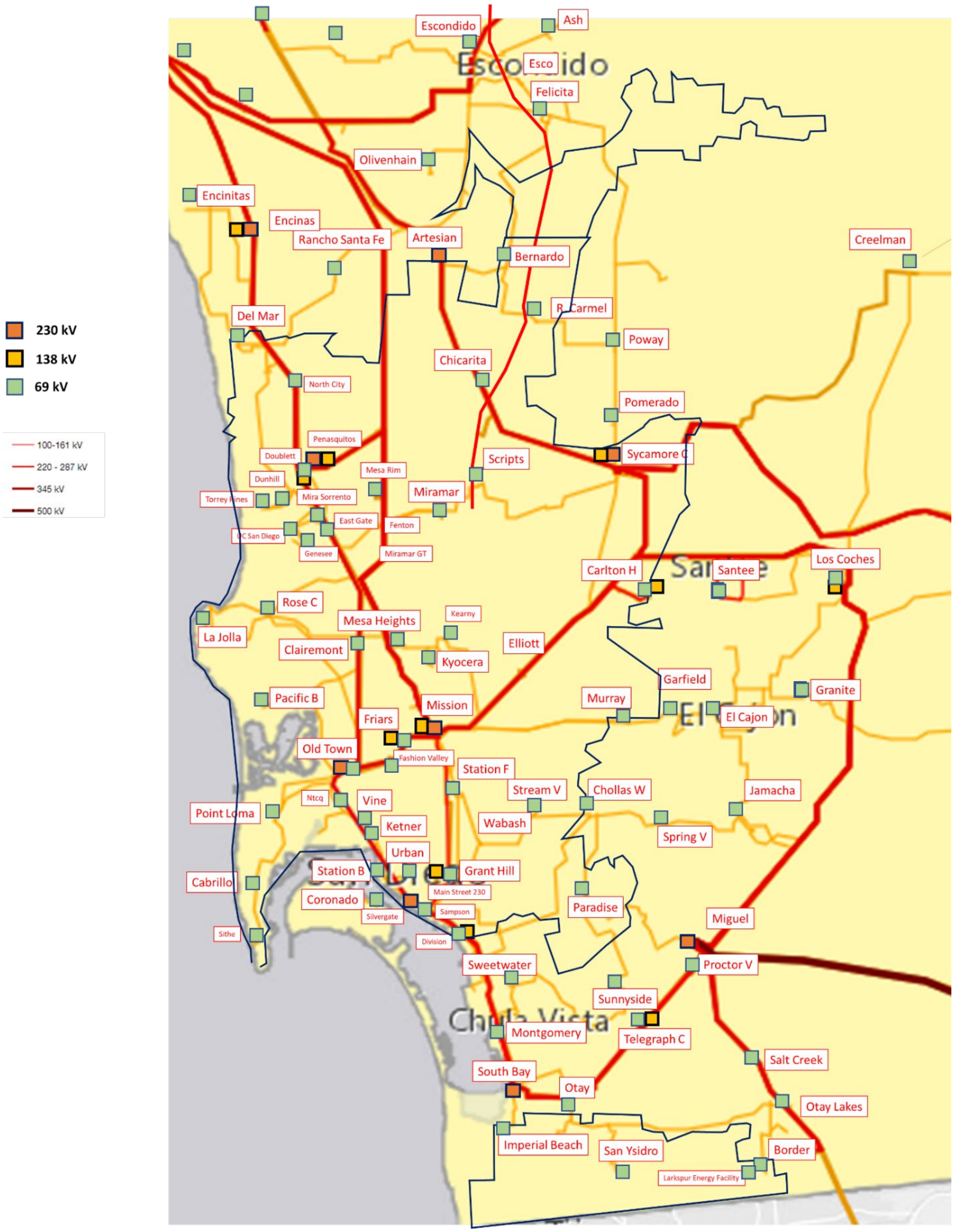


Figure 5-2. Transmission Lines

Valuation Approaches

Two estimated valuation approaches were used for the Phase I report. The first is the RCN which is an estimate of the cost of building the same exact assets today. Note that this approach is based on reproducing exactly the same assets and not their optimal functional equivalent, which could be different given the state of the technology and the way in which the system was actually expanded. To determine the RCN, the inventory quantities were multiplied by unit costs based on industry standards for determining the cost to build the assets in California and in San Diego in particular.

The second method is the Original Cost (OC), which is used to estimate the cost of the assets when they were originally built. To develop acquisition costs, estimates of the depreciation of the assets were applied to the RCN to develop the RCNLD as well as the OCLD.

Objectives of Phase I

The central objective of this Phase I report is to provide reasonable estimates of the RCN, OC, RCNLD, and OCLD values that will be further refined in the future. Therefore, some simplifying assumptions were made for the estimated T&D valuations and inventory as described in the sections below.

Transmission Valuation

Estimated Transmission Inventory

The estimated transmission inventory was largely derived from the information contained in the WECC load-flow cases that provide information on the topology of the transmission network and the voltage and ratings of equipment. This information was complemented by FERC Form 1 data from SDG&E and the California Electric Infrastructure that provided the location of substations.[6]

Using the above information, the NewGen Team identified the HV substations inside the City (City Substations), those at the border (Border Substations), and the balance of SDG&E substations. For each of these substations, the number of lines connecting to it and the transformers by voltage level are identified. This information is complemented with the number of MV feeders connected to each substation that were obtained from the distribution analysis. With this information, the number of breakers by voltage level was estimated, assuming a typical layout, the number and capacity of transformers, and the MV (12 kV) assets that the City would need to acquire at the City Substations. For the Border Substations, the same information was collected, but, in this case, only the HV/MV transformers were considered as well as the MV yard assets required to supply the City's load.

Table 5-1 below shows the information gathered for the City Substations. Note that in this table "positions" are used instead of breakers. A position represents an entry for equipment connection and is used to estimate the number of breakers; for example, a "breaker and one-half" substation would have 1.5 breakers per position. Table 5-2 provides the same information for the Border Substations.

[6] https://caenergy.maps.arcgis.com/apps/webappviewer/index.html?id=ad8323410d9b47c1b1a9f751d62fe495

Table 5-1
Substations Inside the City of San Diego

			Line Positions for City @ kV		Transformers Installed Capacity		Number of Transformers		
Substation Name	% Load Served Inside City	City Load	138	69	138/69 MVA	HV/MV MVA	138/69 Units	HV/MV Units	City Feeders
CABRILLO	100%	32.98		2	0	56	0	2	4
CHICARITA	90%	50.20			0	84	0	3	10
CLAIREMONT	100%	37.94		2	0	56	0	2	6
DOUBLETT	0%	-	1	1	0	0	0	0	2
DUNHILL	0%	-		1	0	8	0	1	2
EASTGATE	100%	30.98		2	0	56	0	2	6
ELLIOTT	100%	47.64		3	0	84	0	3	7
FRIARS	100%	37.14	2		0	56	0	2	8
GENESEE	100%	88.73		3	0	112	0	4	16
GRANT HILL	100%	25.96	2		0	56	0	2	7
KEARNY WEST	100%	55.81		3	0	112	0	4	13
KETTNER	100%	15.53		2	0	56	0	2	3
KYOCERA	100%	2.78		1	0	9	0	1	1
LA JOLLA	100%	25.48		2	0	56	0	2	6
MESA HEIGHTS	100%	45.39		2	0	84	0	3	11
MESA RIM	100%	79.94		4	0	112	0	4	14
MIRA SORRENTO	100%	38.68		2	0	56	0	2	8
MIRAMAR	100%	55.15		4	0	84	0	3	12
MISSION	100%	88.25	3	8	672	112	3	4	16
NORTH CITY WEST	100%	53.87		2	0	56	0	2	7
OLD TOWN	100%	66.42		4	0	84	0	3	12
PACIFIC BEACH	100%	48.41		2	0	56	0	2	8
PARADISE	77%	35.86		3	0	56	0	2	7
PENSQTOS	0%	-	2	11	868	0	5	0	2
POINT LOMA	100%	46.66		4	0	84	0	3	9
RANCHO CARMEL	72%	32.44		2	0	84	0	3	8
ROSE CANYON	100%	41.51		6	0	56	0	2	9
SAMPSON	91%	-		3	0	0	0	1	15
SAN YSIDRO	86%	37.24		2	0	56	0	2	9
SCRIPPS	100%	61.32		2	0	84	0	3	12
SILVERGT	0%	-		9	0	0	0	0	2
STATION F	100%	67.80		2	0	84	0	3	10
STREAMVIEW	100%	44.53		2	0	56	0	2	8
TORREY PINES	100%	62.77		3	0	112	0	4	14
UCM	0%	-		2	0	0	0	0	2
URBAN	100%	60.45		2	0	84	0	3	14
VINE	100%	59.33		2	0	56	0	3	11
WABASH CANYON	100%	11.56		3	0	0	0	0	3

Table 5-2
Substations at the Border of the City of San Diego

			Line Positions for City @ kV		Transformers Installed Capacity		Number of Transformers		
Substation Name	**% Load Served Inside City**	**City Load**	**138**	**69**	138/69 MVA	HV/MV MVA	138/69 Units	HV/MV Units	City Feeders
ARTESIAN	0%	-			0	56	0	2	7
BAY BLVD	0%	-			0	0	0	0	2
BERNARDO	70%	54.33		1	0	140	0	5	18
BORDER	48%	17.13		1	0	56	0	2	6
CARLTON HILLS	19%	6.44	1		0	56	0	2	5
CHOLLAS WEST	55%	30.85		2	0	56	0	2	9
CORONADO	17%	-		1	0	0	0	2	1
DELMAR	42%	25.26		3	0	84	0	3	10
DIVISION	0%	-			0	0	0	1	2
ENCINA	0%	-			0	0	0	0	2
FELICITA	32%	16.93			0	84	0	3	5
GARFIELD	9%	1.48			0	28	0	1	1
IMPERIAL BEACH	56%	24.69			0	56	0	2	9
LOS COCHES	0%	-		1	448	84	2	3	2
MIGUEL	0%	-			0	0	0	2	2
MURRAY	57%	48.08		2	0	112	0	4	10
NATNLCTY	0%	-		1	0	14	0	2	2
OLIVENHAIN	8%	-			0	0	0	0	1
OTAY	86%	25.48			0	56	0	2	2
OTAY LAKES	11%	0.13			0	5	0	1	1
POMERADO	44%	27.84			0	84	0	3	3
POWAY	11%	4.00		1	0	56	0	2	2
RANCHO SANTA FE	3%	0.66			0	41	0	2	1
SAN LUIS REY	0%	-			0	112	0	4	2
SANTA YSABEL	0%	-			0	0	0	0	2
SHADOWR	0%	-	1		0	84	0	3	2
SYCAMORE	0%	-	1	2	0	0	0	0	2
STATION B	100%	81.30		4	0	112	0	4	23
SUNNYSIDE	22%	2.42		1	0	28	0	1	1
SWEETWATER	6%	2.62			0	56	0	2	1
TELECYN	0%	-	1		0	112	0	4	2

Transmission lines voltage, capacity, and length were derived from the WECC load flows, and whether the facility was an overhead line or an underground cable was identified by considering the line parameters (low "surge impedance" implies a cable). As previously mentioned, only the 138 kV and 69 kV lines that interconnect the City Substations are considered for acquisition in this Phase I analysis.

Table 5-3 below provides a summary of miles estimated by voltage level as well as a summary of the breakers and transformers by voltage level to be acquired by the City on the minimum acquisition option described above. The table also indicates a "Substation Layout Cost;" this is a standardized value with a unit cost priced to incorporate other equipment (e.g., roads, fences, bus-work, communication, protection, etc.) which is not already included with the price of the major equipment on a typical substation. The table also includes the quantities estimated for SDG&E as a whole.

Table 5-3
Estimated Transmission System Inventory

		San Diego MEU	SDG&E
Overhead lines (miles)	500 kV	0	303
	230 kV	0	397
	138 kV	27.8	193
	69 kV	122.6	795
	Other	0	0
	Total	**150.4**	**1688**
Underground Cables (miles)	500 kV	0	0
	230 kV	0	93
	138 kV	6.2	26
	69 kV	34.1	115
	Other	1	4
	Total	**41.3**	**238**
	Total	**191.7**	**1926**

Transformers (MVA)	500kV/230 kV	0	12,320
	230 kV/138 kV	1,176	5,750
	230 kV /69 kV	896	4,032
	138 kV /69 kV	1,540	2,214
	HV/MV	2,798	6,713
	Total	**6,410**	**31,029**

Total Breakers per KV level	**500** kV	0	35
	230 kV	0	183
	138 kV	25	127
	69 kV	244	807
	MV	1120	2481
Total Layout Costs per KV level	**500** kV	0	3
	230 kV	0	15
	138 kV	2	10
	69 kV	20	67
	MV	0	0

Transmission RCN and OC

The NewGen Team determined the RCN of the assets using unit costs and considering various sources including:

- 2021 PG&E Proposed Generator Interconnection Unit Cost Guide
- WECC Substation Capital Cost Calculator
- SDG&E Rule 21 Unit Cost Guide
- MISO MTEP Cost Estimating Guide 2022
- RSMeans Electrical Data Cost 2022
- Transmission Infrastructure Cost Estimating Guide_ 2021 Update (EPRI)
- Siemens Energy Costs for GIS substations

Various sources were consulted as there is not a single source with all unit costs needed, and this allowed for a comparison and selection of a representative accounting approach, which includes factors such as the size of the projects and the costs included in the unit costs.

Table 5-4 below shows the Base RCN of the individual assets to be acquired by the City as a result of this analysis, as well as the corresponding values for the entirety of SDG&E's transmission assets. This value is required for the determination of the OC value of the City's transmission assets, as presented later in this report.

Table 5-4
Transmission System Base RCN 2022 by Asset Type and Voltage Level ($M)

		Unit Cost 2022$/mile	San Diego MEU ($M)	SDG&E ($M)
Overhead lines (miles)	500	$6,890,904	$0	$2,090
	230	$4,627,916	$0	$1,839
	138	$3,272,430	$91	$631
	69	$2,650,249	$325	$2,106
	Other	$2,650,249	$0	$0
	Total		**$416**	**$6,666**
Underground Cables (miles)	500			
	230	$23,096,029	$0	$2,150
	138	$22,484,546	$139	$585
	69	$22,412,069	$764	$2,573
	Other	$22,412,069	$22	$92
	Total		**$926**	**$5,400**
Transformers (MVA)	500kV/230	$34,076	$0	$420
	230/138	$33,289	$39	$191
	230/69	$31,991	$29	$129
	138/69	$27,771	$43	$61
	HV/MV	$23,540	$66	$158
	Total		**$176**	**$960**
Total Breakers per KV level	500	$2,791,061	$0	$96
	230	$1,938,237	$0	$354
	138	$1,487,207	$37	$189
	69	$1,338,434	$326	$1,080
	MV	$128,295	$144	$318
Total Layout Costs per KV level	500	$18,334,963	$0	$55
	230	$11,486,964	$0	$172
	138	$8,551,249	$17	$86
	69	$7,383,801	$148	$495
	MV	Metal Clad		
	Total		**$672**	**$2,845**
Total Transmission Assets RCN ($M)			**$2,190**	**$15,870**

The assets in Table 5-4 above include the HV/MV transformers and the MV yard that are part of the distribution system according to FERC accounting rules. Thus, in Table 5-5 below, the assets are consolidated using FERC rules and the substations only include the HV yards (138 kV and 69 kV) and the high voltage to high voltage (the HV/HV) transformers (i.e., 138/69 kV). This table shows that the transmission RCN is estimated to be approximately $2.5 billion, which includes 10% contingency and 20% owner's overhead costs. The contingency is intended to capture both errors in the inventory and the unit costs, and the owner's costs account for costs beyond the EPC including back-office administrative costs, owner's engineer, corporate fleet transportation provided, etc. The table also shows the estimated RCN for SDG&E assets, which is approximately $20.3 billion. Note that the MEU, under the assumptions made for transmission asset acquisition, is largely a distribution company, and their transmission assets are a fraction of those owned by SDG&E (approximately 12%).

Table 5-5
Estimated Transmission RCN 2022 ($M)(1)

	MEU	SDG&E
Transmission Overhead	$400	$6,700
Transmission Underground	$900	$5,400
Substations Transmission (HV & HV/HV XMR)	$600	$3,300
Total Transmission before Contingency & Owner's Costs	$1,900	$15,400
Owner's Costs (20%)	$400	$3,100
Contingency (10%)	$200	$1,800
Total Transmission RCN	$2,500	$20,300

(1) Totals may not add due to rounding.

The ratio of the RCN for the MEU's transmission assets in Table 5-5 to the corresponding value of SDG&E was used to determine the OC for the assets to be acquired by applying these ratios to the values reported by SDG&E for the plant in service in 2021. Table 5-6 below shows the OC of the transmission assets to be acquired. This analysis suggests an OC of approximately $1 billion for the MEU and approximately $8.1 billion for SDG&E.

Table 5-6
Transmission Original Cost 2022 ($M)(1)

.	MEU	SDG&E
Transmission Overhead	$200	$3,800
Transmission Underground	$200	$1,200
Substations (includes land & others)	$500	$3,000
Total	$1,000	$8,100

(1) Totals may not add due to rounding.

Transmission Depreciation (Age of Asset)

Accurate asset age estimation for the transmission and distribution assets is challenging even when detailed information is available. For the Phase I report, the NewGen Team estimated an average cumulated depreciation of assets using the ratio of the book accumulated depreciation to the original costs, which resulted in approximate 22% depreciation. Table 5-7 below shows the estimated depreciated values.

Table 5-7
Estimated Transmission Values Summary 2022 ($M)(1)

	OC	OCLD	RCN	RCNLD
Electric Transmission Assets for MEU	$1,000	$800	$2,500	$2,000

(1) Totals may not add due to rounding.

Distribution Valuation

Estimated Inventory & Costs

The distribution inventory developed for this Phase I report consisted of a combination of top-down and bottom-up approaches. The length of feeders by voltage level and type (overhead/underground) inside the City was estimated from various sources including the Integration Capacity Analysis (ICA) maps made available by SDG&E online. The corresponding values for SDG&E as a whole were obtained from the information filed in the 2024 GRC by SDG&E. The load connected to these feeders was obtained from SDG&E's Grid Needs Assessment (GNA) reports filed with the CPUC, and the percentage of load served inside the City was determined by inspection of the ICA maps.

The number and capacity of the distribution transformers (MV/LV) and the number of switches and reclosers, capacitor banks, voltage regulators, and LV networks were estimated using top-down ratios derived from comparable systems. This was done by considering the density (MV load/length of feeder) and level of undergrounding (UG cabled/total feeders) by substation. Using this procedure, the values in Table 5-8 below were derived for the distribution system to be acquired by the City. This table also shows the unit costs and the total value in 2022 dollars. The unit costs were derived from the RSMeans estimating databases, an industry accepted source of cost data. Total values are rounded to the nearest hundred thousandth place and are shown below in $000.

Table 5-8
Estimated Distribution Inventory Detail[(1)]

Device	Unit	Count	Unit Cost $	Total 000$
4.16 kV three-phase riser	Unit	544	$8,368	$4,600
12.47 kV three-phase riser	Unit	1912	$9,829	$18,800
Feeder Automation 4.16 kV	Unit	195	$54,613	$10,600
Feeder Automation 12.47 kV	Unit	615	$54,613	$33,600
40 to 45 foot pole, with all hardware and accessories 4.16 kV	Unit	3450	$5,847	$20,200
40 to 45 foot pole, with all hardware and accessories 12.47 kV	Unit	12490	$5,847	$73,000
60 foot pole, with all hardware and accessories (double circuit, both voltages)	Unit	3989	$8,032	$32,000
Switch 4 kV OH	Unit	695	$5,249	$3,600
Switch 12 kV OH	Unit	2561	$5,249	$13,400
Switch 4 kV UG	Unit	470	$71,892	$33,800
Switch 12 kV UG	Unit	10653	$79,919	$851,400
Capacitor 4 kV OH	Unit	113	$4,879	$600
Capacitor 12 kV OH	Unit	406	$9,757	$4,000
4.16 kV Overhead feeder, 3 # 4/0 AWG AL, on insulators	Miles	35	$79,624	$2,800
12.47 kV Overhead feeder, 3 # 4/0 AWG AL, on insulators	Miles	86	$119,468	$10,300
4.16 kV Overhead feeder, 3 # 715 kcmil AL, on insulators	Miles	48	$212,246	$10,200
12.47 kV Overhead feeder, 3 # 715 kcmil AL, on insulators	Miles	212	$224,981	$47,600
4.16 kV Underground feeder, 3# 4/0 AWG XLPE, on conduits	Miles	20	$286,636	$5,600
4.16 kV Underground feeder, 3# 1000 kcmil XLPE, on conduits	Miles	38	$458,617	$17,500
12.47 kV Underground feeder, 3# 4/0 AWG XLPE, on conduits	Miles	410	$387,497	$158,900
12.47 kV Underground feeder, 3# 1000 kcmil XLPE, on conduits	Miles	796	$619,994	$493,500
2 Duct Bank for 4.16 Feeders	Miles	23	$1,001,479	$23,200
2 Duct Bank for 12.47 kV Feeders	Miles	482	$1,001,479	$483,100
4 Duct Bank for 4.16 kV Feeders	Miles	35	$1,525,989	$53,000
4 Duct Bank for 12.47 kV Feeders	Miles	724	$1,525,989	$1,104,200
Step Down Transformers*	Unit	130	$54,467	$7,100

Table 5-8
Estimated Distribution Inventory Detail[1]

Device	Unit	Count	Unit Cost $	Total 000$
Transformers				
Overhead single-phase Transformer 1x50 kVA 4.16 kV	Unit	1105	$7,410	$8,200
Pad Mounted three-phase Transformer 1x300 kVA 4.16 kV	Unit	78	$39,759	$3,100
Pad Mounted three-phase Transformer 1x500 kVA 4.16 kV	Unit	51	$53,345	$2,700
Overhead single-phase Transformer 1x50 kVA 12.47 kV	Unit	4157	$7,410	$30,800
Overhead single-phase Transformer 1x100 kVA 12.47 kV	Unit	3111	$10,447	$32,500
Pad Mounted three-phase Transformer 1x300 kVA 12.47 kV	Unit	1496	$39,759	$59,500
Pad Mounted three-phase Transformer 1x500 kVA 12.47 kV	Unit	969	$53,345	$51,700
Subsurface three-phase Transformer 1x300 kVA 12.47 kV	Unit	1649	$192,517	$317,500
Subsurface three-phase Transformer 1x500 kVA 12.47 kV	Unit	764	$225,087	$172,000
Spotnetwork three-phase Transformer 1x750 kVA 12.47 kV	Unit	585	$314,755	$184,100
Spotnetwork three-phase Transformer 1x1000 kVA 12.47 kV	Unit	107	$359,499	$38,500
OVERHEAD LOW VOLTAGE CIRCUITS				
Overhead Low Voltage 1C Triplex # 6 AWG CU from 4.16 kV	Mile	3.56	$29,508	$100
Overhead Low Voltage circuit 3 # 2 AWG CU from 4.16 kV	Mile	1.82	$110,860	$200
Overhead Low Voltage circuit 3 # 1/0 AWG AL from 4.16 kV	Mile	8.51	$102,709	$900
Overhead Low Voltage 1C Triplex # 6 AWG CU from 12.47 kV	Mile	13.41	$29,508	$400
Overhead Low Voltage circuit 3 # 2 AWG CU from 12.47 kV	Mile	6.86	$110,860	$800
Overhead Low Voltage circuit 3 # 1/0 AWG AL from 12.47 kV	Mile	32.01	$102,709	$3,300
SERVICE DROP AND UNDERGROUND SERVICE				
Low Voltage Service Drop, OH, 50 Feet, 1C triplex 1/0 Al for 4.16 kV	Unit	11050	$736	$8,100
Low Voltage Service Drop, UG, 50 Feet, 2C 3#1000 Al + 350 Al (n) for 4.16 kV	Unit	51	$11,177	$600
Low Voltage Service Drop, UG, 50 Feet, 3C 3#1000 Al + 350 Al (n) for 4.16 kV	Unit	51	$16,766	$900
Low Voltage Service Drop, OH, 50 Feet, 1C triplex 1/0 Al for 12.47 kV	Unit	41570	$736	$30,600
Low Voltage Service Drop, UG, 50 Feet, 1C 3#1000 Al + 350 Al (n) for 12.47 kV	Unit	1649	$5,589	$9,200
Low Voltage Service Drop, UG, 50 Feet, 2C 3#1000 Al + 350 Al (n) for 12.47 kV	Unit	1733	$11,177	$19,400
Low Voltage Service Drop, UG, 50 Feet, 3C 3#1000 Al + 350 Al (n) for 12.47 kV	Unit	585	$16,766	$9,800

Table 5-8
Estimated Distribution Inventory Detail(1)

Device	Unit	Count	Unit Cost $	Total 000$
Streetlights	Unit	0	$1,000	$0
Meters				
Residential	Unit	$629,300	$998	$629,259
Commercial	Unit	$122,100	$1,853	$122,139
Industrial	Unit	$200	$2,058	$224
Subtotal				**$5,252,800**

(1) Totals may not add due to rounding.

Distribution RCN and OC

Table 5-9 below shows that the RCN of the distribution assets to be acquired by the City is estimated to be approximately $7.3 billion. This value is derived from the results in Table 5-8, including the estimated value of the HV/MV transformers, a 10% contingency, and 20% owner's costs. The table also shows the estimated RCN of the entirety of SDG&E's distribution assets of approximately $22.8 billion.

Table 5-9
Estimated Distribution RCN 2022 ($M)(1)

	MEU	SDG&E
Distribution Overhead	$200	$1,500
Distribution Underground	$2,300	$9,900
Substations Distribution (MV & HV/MV XMR)	$300	$500
Distribution Transformers	$900	$1,500
Distribution Reclosers, Switches & Others	$1,000	$2,100
Meters & Services (LV)	$800	$1,800
Streetlights	$0	$0
Total Distribution before Contingency & Owner's Costs	$5,500	$17,300
Owner's Costs (20%)	$1,100	$3,500
Contingency (10%)	$700	$2,100
Total Distribution RCN	$7,300	$22,800

(1) Totals may not add due to rounding.

The ratio of the RCN for the MEU's distribution assets in Table 5-9 above to the corresponding value of SDG&E was used to determine the OC for the assets to be acquired by applying these ratios to the values reported by SDG&E for the plant in service in 2021. Table 5-10 below shows the OC of the distribution assets to be acquired, which is estimated to be approximately $2.9 billion for the MEU.

Table 5-10
Estimated Distribution Original Cost 2022 ($M)(1)

	MEU	SDG&E
Distribution Overhead	$300	$2,400
Distribution Underground	$900	$4,000
Substations Distribution (MV & HV/MV XMR)	$400	$700
Distribution Transformers	$500	$900
Distribution Others	$200	$300
Meters & Services (LV)	$500	$1,200
Streetlights	$0	$40
Total	$2,900	$9,400

(1) Totals may not add due to rounding.

Distribution Asset Depreciation (Age of Asset)

As with the transmission assets, the average cumulated depreciation of distribution assets was estimated using the ratio of the book accumulated depreciation to the original costs, which resulted in approximately 40% depreciation. Table 5-11 shows the estimated distribution asset values developed for this report.

Table 5-11
Distribution Value Summary 2022 ($M)(1)

	OC	OCLD	RCN	RCNLD
Electric Distribution	$2,900	$1,700	$7,300	$4,200

(1) Totals may not add due to rounding.

Total Estimated Acquisition Value

Table 5-12 shows the summary of the estimated RCN, RCNLD, OC, and OCLD of the assets to be acquired by the City. As noted in Section 8, values utilized in the financial feasibility analysis are escalated as appropriate for the year in which they are expected to occur.

Table 5-12
Estimated Asset Valuation Summary 2022 ($M)(1)

	OC	OCLD	RCN	RCNLD
Electric Distribution	$2,900	$1,700	$7,300	$4,200
Electric Transmission	$1,000	$800	$2,500	$2,000
Total	$3,800	$2,400	$9,800	$6,200

(1) Totals may not add due to rounding.

Section 6
SEVERANCE COSTS (PRELIMINARY)

The purpose of this section is to provide a preliminary evaluation of the potential severance costs that may exist if the City were to form an MEU. Severance refers to the separation of assets after the acquisition between the City's MEU and SDG&E so that the MEU only serves customers within the City's municipal border and SDG&E continues to serve those customers outside the City's border. Severance costs are appliable at the transmission level and the distribution level.

Key Considerations

The development of a severance plan in its implementable form is an elaborate engineering task that requires accurate information on the existing assets to be affected by the acquisition. Thus, severance should be carried out without deteriorating the reliability of the system in a least cost manner and in compliance with all environmental laws, including the CEQA.

For this Phase I report, simplifying approximations have been made as described herein under the applicable preliminary Transmission Severance Plan and Distribution Severance Plan sections.

Preliminary Transmission Severance Plan

Transmission severance occurs at the Border Substations that supply load inside the City and at the City Substations that supply load outside the City. This implies the City would need to make investments to separate the supply of the feeders that go inside the City from those that remain outside for the Border Substations. Similarly, the City would need to make investments to separate the feeders from City Substations that serve outside the City.

For the estimated severance costs, it is assumed conservatively that a new 26 mega-volt ampere (MVA) MV/LV transformer will be required for the severance, either for SDG&E or for the MEU, as well as two 69 kV or 138 kV breakers for the connection of the transformer and HV yard substation reconfiguration. Four 12 kV breakers are assumed for the separation at MV, one for the transformers and three for the feeders estimated to be required to split the load between the MEU and SDG&E.

Table 6-1 below shows the estimated costs that apply to the Border Substations and the City Substations that supply load outside the City boundaries (rounded total values)

Table 6-1
Costs at Each Border Substation that Feeds Load Inside the City(1)

Item	Unit or MVA	Unit Cost ($000)	2022 ($000)
Transformer	26	$24	$600
Breaker 138 kV (in most cases will be 69 kV)	2	$3,272	$6,500
Breaker 12 kV	4	$128	$500
Layout 138 kV (in most cases will be 69 kV)	0.5	$8,551	$4,300
Total			$11,900

(1) Totals may not add due to rounding.

Based on information provided by the City and SDG&E, it is estimated that there are 25 substations that are either inside the City serving load outside the City or are outside the City serving load inside the City. Using the unit costs above, it is estimated that the transmission severance cost (based on RCN) will be approximately $457 million, including 25% contingency and 20% owner's costs, as detailed in Table 6-2 below. The larger contingency amount recognizes the high-level nature of the information available for review at this Phase I analysis. The owner's costs account for costs beyond the EPC including back-office administrative costs, owner's engineer, corporate fleet transportation provided, etc.

Table 6-2
Estimated Transmission Severance Costs(1)

	Total Substations	Unit Cost ($000)	2022 ($000)
Base Cost for substations serving load inside and outside City	25	$12,200	$305,000
Contingency 25%			$76,200
Owner's Costs 20%(2)			$76,200
Total Cost			$457,500

(1) Totals may not add due to rounding.

(2) The Owner's Costs 20% applies to the initial cost plus the Contingency.

It is important to note that under the minimum transmission investments option selected for this Phase I report, the HV side of the Border Substations remains with SDG&E and there is no severance at this level, only metering of the transformers that supply the City's MEU MV yard.

Preliminary Distribution Severance Plan

Distribution severance costs were estimated based on the number of times that a feeder crosses the City's municipal border. The number of border crossings accounts for the feeders that start outside at an Border Substation and go inside the City as well as feeders that started at the City's Substations and serve load outside the City's boundaries. The estimate was based on the number of feeders at each substation divided into those supplying load inside the City, those supplying load outside the City, and the percentage of the load that is supplied inside the City. For substations inside the City that had at least one feeder serving load outside the City, the number of crossings was assumed to be proportional to the total number of feeders at the substation times the percentage of the load served outside the City.

For Border Substations that served load inside the City (which are the majority of the substations with severance issues), the number of crossings was assumed to be equal to the sum of: a) the number of feeders that serve load inside the City, plus b) the number of feeders serving load outside times the percentage of the load served inside the City, plus c) the numbers of feeders serving load inside the City, times the percentage of the load served outside the City. This approach takes into consideration that feeders frequently get close to the City border and supply some loads on the "other side" and the greater the percentage of this "other side" load, the more likely it is to happen. A total of 306 feeder border crossings were estimated from the data provided by the City and SDG&E.

To determine the cost per border crossing, it was assumed that the point of crossing would need to be electrically "rearranged." This means that costs were estimated to reconnect SDG&E customers that would otherwise remain connected to the City or to reconnect City customers that would otherwise remain connected to SDG&E. Additionally, based on the NewGen Team's experience, there is generally an adjacent feeder that could be used for this reconnection. With this in mind, costs were estimated based on 500 feet of 12 kV underground cable, two pad mounted 300 kilovolt-ampere (kVA) transformers, four new 12 kV switches, and eight LV underground service connections. These estimated costs are shown in Table 6-3 and are considered conservative, as the total costs applied to all border crossings are likely to require fewer transformers, and shorter lines and fewer reconnections would be necessary. However, this level of detail is beyond the scope of this Phase I report.

Table 6-3
Estimated Unit Cost per Feeder Crossing(1)

	Count or ft.	Unit Cost ($000)	2022 ($000)
Pad Mounted Three-phase Transformer 1x300 kVA 12.47 kV	2	$40	$100
12.47 kV Underground feeder, 3# 1000 kcmil XLPE, on Conduits	500	$600	$100
2 Duct Bank for 12.47 kV Feeders	500	$1,000	$100
Switch 12 kV UG	4	$100	$300
Low Voltage Service Drop, UG, 50 Feet, 2C 3#1000 Al + 350 Al (n) for 12.47 kV	8	$10	$100
Total			$600

(1) Totals may not add due to rounding.

Based on the costs on a "per feeder crossing," the cost of the distribution severance is estimated to be approximately $254 million, which includes 25% contingency and 20% owner's overhead costs as previously described. Table 6-4 provides a summary of the estimated total distribution severance costs. As noted in Section 8, values utilized in the financial feasibility analysis are escalated as appropriate for the year in which they are expected to occur.

Table 6-4
Estimated Distribution Severance Costs(1)

Total Cost	Count or ft.	Unit Cost ($000)	2022 ($000)
Estimated Crossings	306	$550	$169,100
Contingency 25%			$42,300
Owner's Costs 20%(2)			$42,300
Total Cost			$253,700

(1) The Owner's Costs 20% applies to the initial cost plus the Contingency

(2) Totals may not add due to rounding.

Section 7
HIGH-LEVEL CAPITAL INVESTMENT REQUIREMENTS (PRELIMINARY)

Preliminary Capital Investment Estimation

The capital expenditures of the MEU are those required to expand the transmission and distribution network in response to anticipated load growth over the Study period. These cost estimates do not include the investments performed by developers on buildings and subdivisions which would be transferred to the MEU. However, these investments do include those addressing the impact that these loads have on the system and the extension of the mainlines to connect these loads as required.

Estimates for future capital expenditures also include those for asset replacement (aging infrastructure) and investment in the network for addressing changes in customer behind the meter load, e.g., EV charging and building electrification after the reduction in load as a result of DER (including customer storage).

Investment Identification Procedure

Under this Phase I report, capital expenditures were estimated based on a review of SDG&E plant in service (investments) for the period 2013 to 2021 (as provided in their FERC Form 1 data). This review noted the investments identified as "Plant Additions + Adjustments & transfers." This value represents the total capital expenditures by year by asset type (Transmission Overhead, Transmission Underground, Substations [includes land & others], Distribution Overhead, Distribution Underground, Substations Distribution [MV & HV/MV transformers], Distribution Transformers, Distribution Others, Meters & Services [LV], and Street Lighting and Signal Systems). The review also noted the retirements by asset type.

Based on this information, the NewGen Team determined the historical capital investment for Asset Replacement and New Load Investment. The investment for Asset Replacement was assumed to be equal to the Retirements expressed in 2022 dollars. Therefore, the equation to estimate new load investment was the total capital expenditure less the retirements (New Load Investments = Total CapEx – Retirements).

The retirements divided by the RCN provided a ratio that was used to project the investment for asset replacement as the RCN increases with the customers and load served by the MEU. The distribution capital expenditure projections were estimated using the ratio of New Load Investments divided by new customers added each year. The average of this ratio (in 2022 dollars) was used for the projections.

For transmission capital expenditures, the investments have a weaker relation to the number of customers added. Therefore, for estimates of these capital expenditures, 20% of the costs were considered to be proportional to investment by new customer and 80% were considered to be proportional to the RCN of transmission per customer.

Load Forecast

To forecast the gross energy load inclusive of energy efficiency and its modifiers, EV charging and DER (self-generation), the NewGen Team used the SDG&E projections provided to the CEC, extended to 2054.

The SDG&E CEC projections were used to produce the projections for the City considering the proportion of customers by customer class to be served by the MEU. Customer growth was assumed to be equal to the 2022 to 2024 projections used by SDG&E in its 2024 GRC (i.e., 1% for residential customers) and reduced by 0.1% for the period 2025–2035 (i.e., 0.9% for residential) and by another 0.1% for the period 2035–2054 (i.e., 0.8% for residential).

Figure 7-1 below shows the forecast for residential customers including gross load inclusive of energy efficiency (in blue), estimated future EV load (orange), and net residential sales (yellow line), which reflects the anticipated growth in DER. The DER is shown by a gray line with yellow dots. This is followed by the commercial customers (Figure 7-2) that also have EV and DG, and then by the industrial (Figure 7-3) and agricultural loads (Figure 7-4).

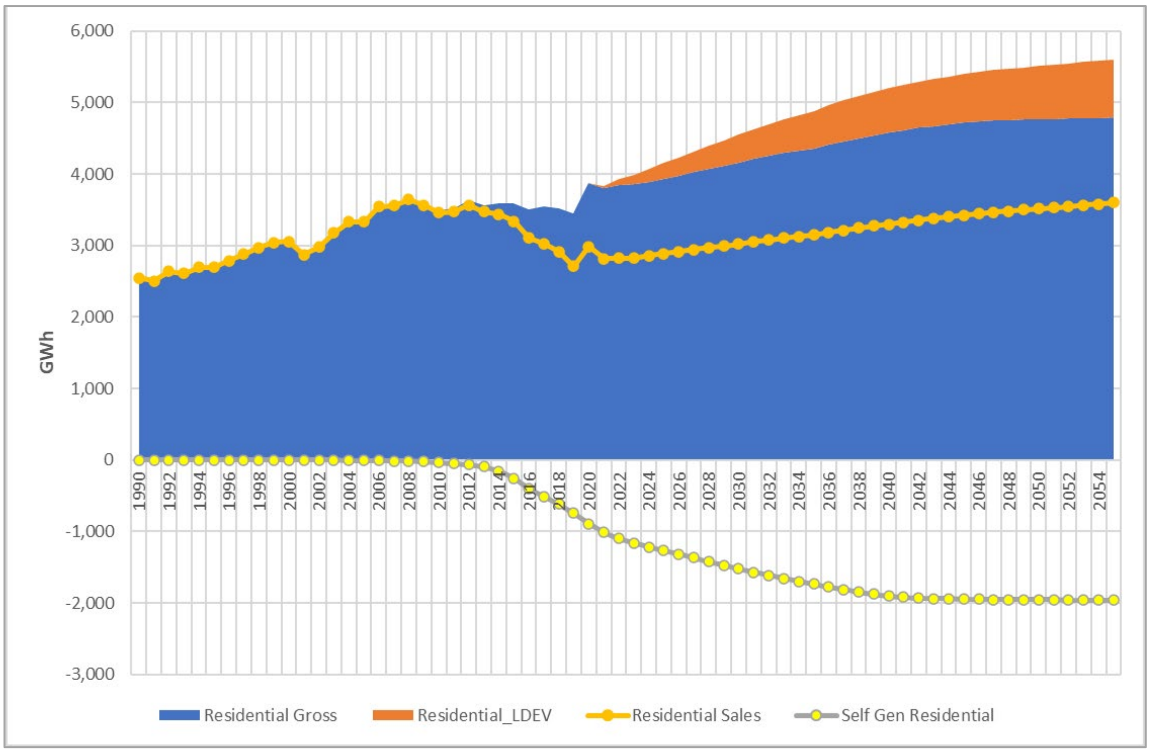
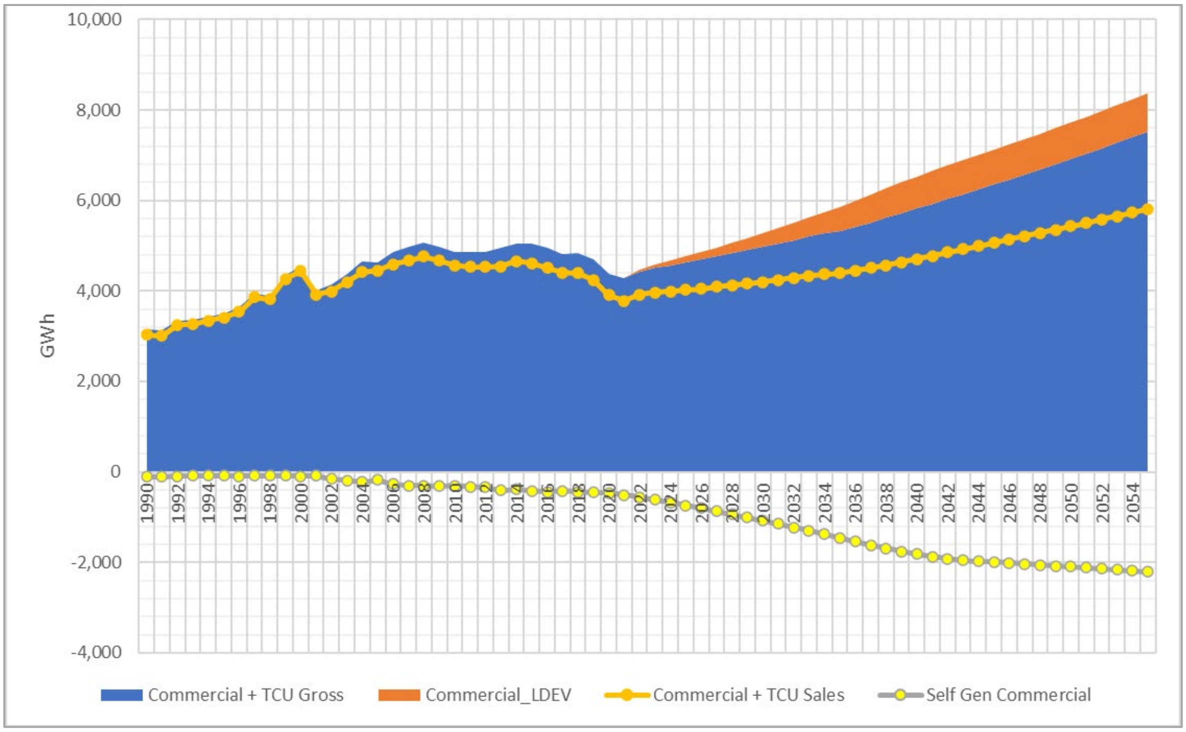


Figure 7-1. Estimated MEU Load Forecast (Residential)



d

Figure 7-2. Estimated MEU Load Forecast (Commercial)

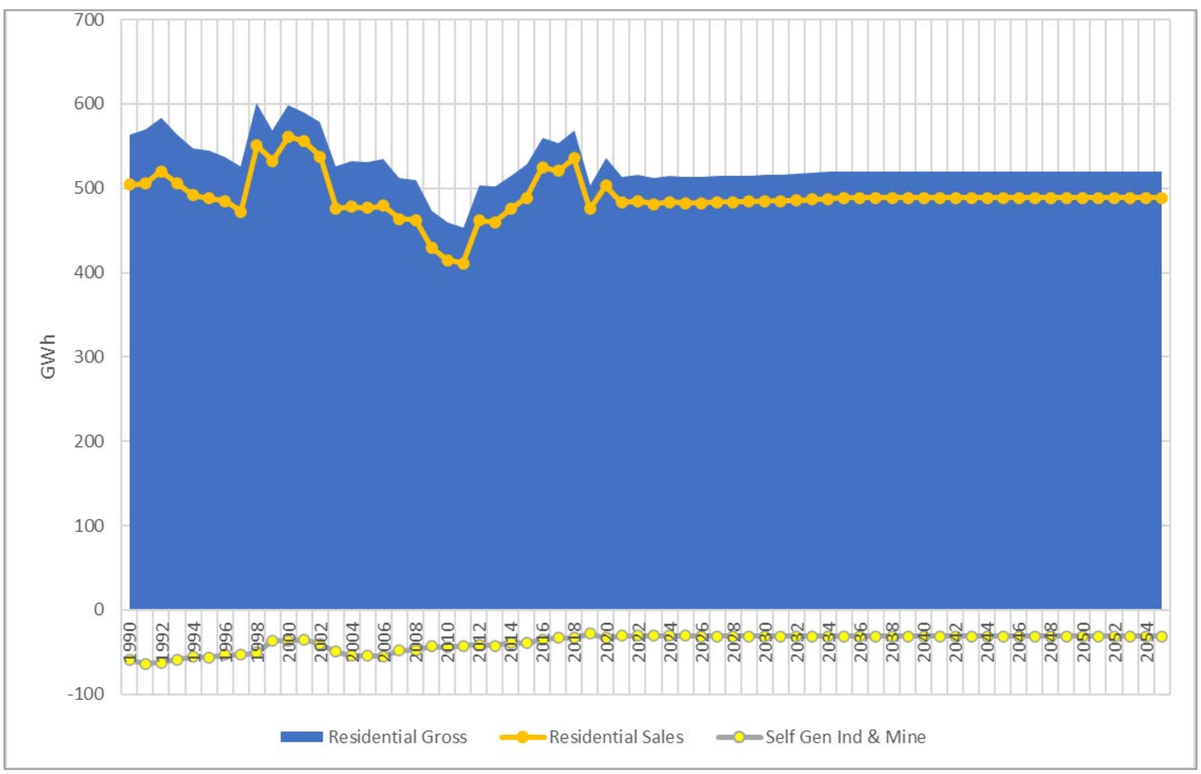


Figure 7-3. Estimated MEU Load Forecast (Industrial)

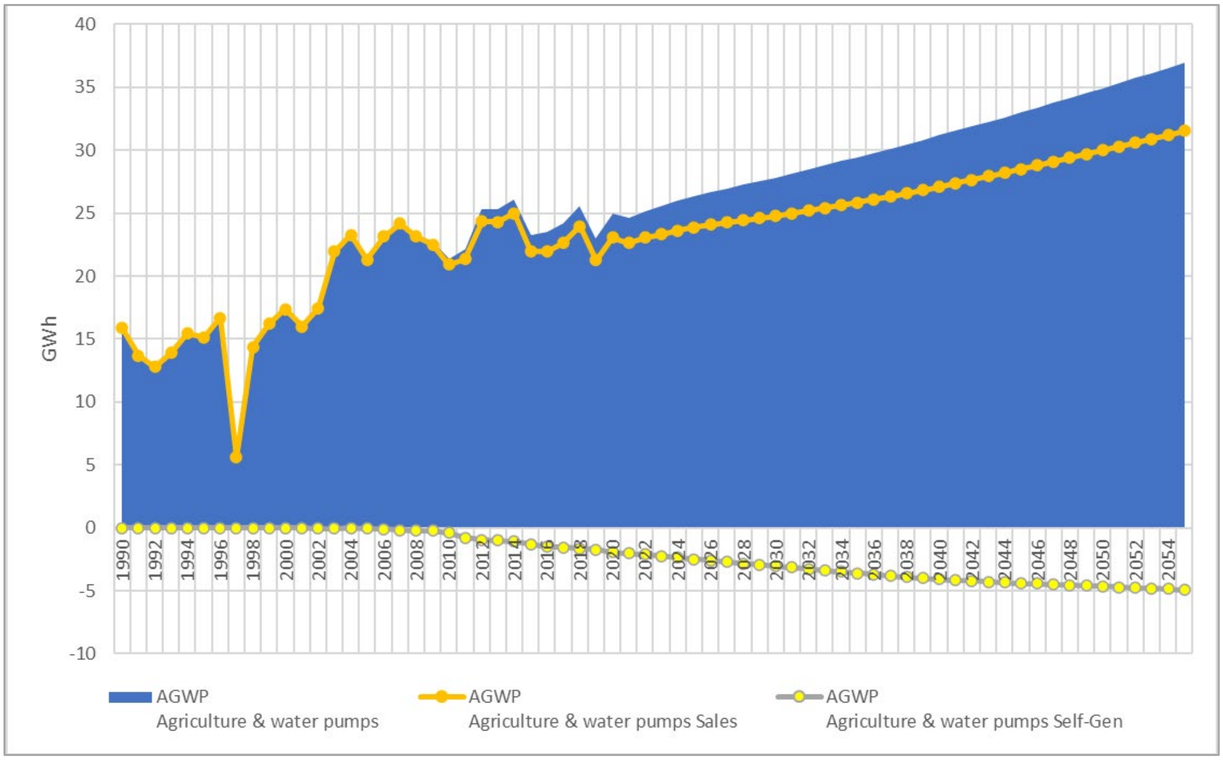


Figure 7-4. Estimated MEU Load Forecast (Agricultural Water Pumps)

Capital Expenditures

Figure 7-5 below shows the estimated capital expenditures by year for the MEU in 2022 dollars (in millions).

This figure shows that for the period between 2024–2033, it is estimated that the MEU will require an investment of approximately $322 million per year. Beyond 2033, it is estimated that the MEU will require approximately $393 million per year on average for the remainder of the forecast period. As noted in Section 8, values utilized in the financial feasibility analysis are escalated as appropriate for the year in which they are expected to occur

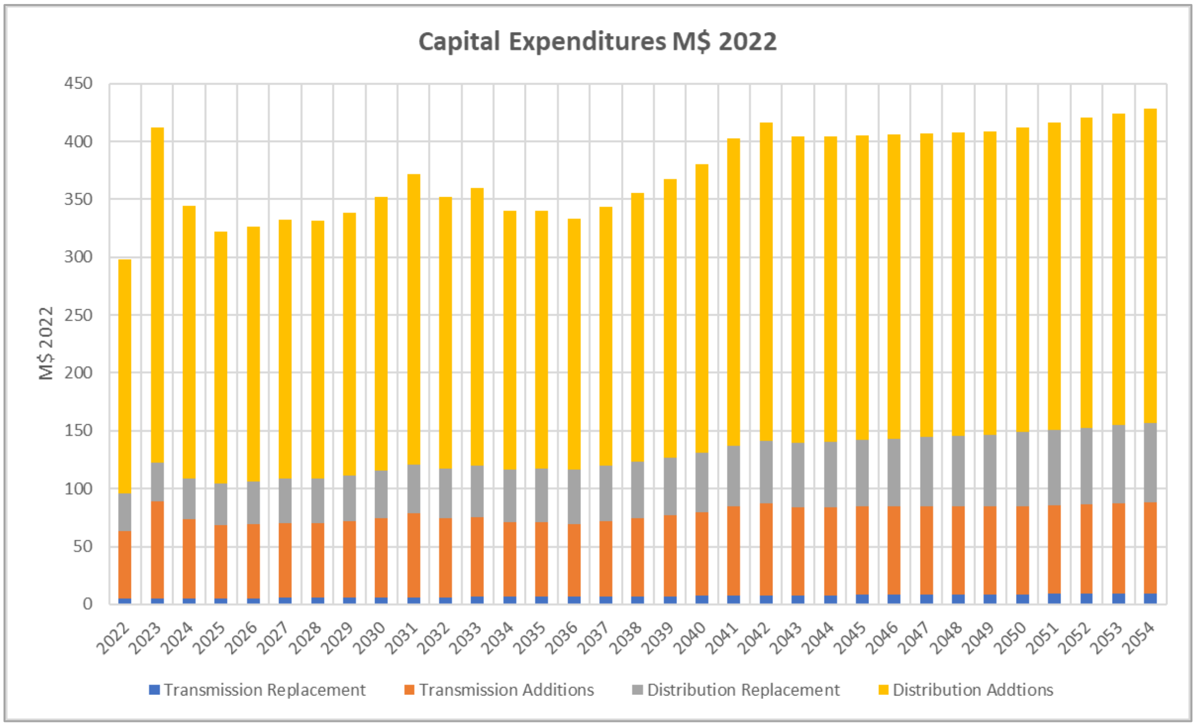


Figure 7-5. Estimated Future Capital Expenditures for MEU

Section 8
FINANCIAL ANALYSIS AND CONSIDERATIONS

Financial Methodology and Approach

To assess the financial feasibility of a potential municipalization effort for the MEU, the NewGen Team prepared a high-level Financial Capacity Analysis. The approach estimates the costs attributable to the municipalization effort and compares them to the current forecasted rates and charges for SDG&E. The Financial Capacity Analysis incorporates: (i) the projected operations, maintenance, meter and billing, system planning, and administration costs (Section 4); (ii) preliminary acquisition costs (Section 5); (iii) preliminary severance costs (Section 6); and (iv) preliminary high-level capital investment requirements (Section 7).

Using these assumptions, the Financial Capacity Analysis integrates and assesses a number of different components to derive high-level financial feasibility, including: i) load forecast, ii) rate forecast, iii) purchase price and financing requirements, iv) debt financing and assumptions, v) operating costs, and vi) financial proforma. Each of these components are interrelated and build on each other to derive the estimated cost or benefit of the MEU when compared to maintaining the provision of transmission and distribution service, in whole or in part, under SDG&E. The cost or benefit is evaluated on both an annual and cumulative basis to determine, where applicable, the estimated term of any payback period using the high-level assumptions identified herein.

The Financial Capacity Analysis begins by creating a baseline for an estimate of currently projected costs which can ultimately be used as a point of comparison for estimated costs under the MEU. The baseline forecast uses a projected load forecast for energy usage, which is universally applied in both the base case (continued service under SDG&E) and MEU to ensure consistency in the projected delivery needs for power to ratepayers. For the SDG&E business model, the load forecast is applied to a rate forecast to estimate the projected revenue requirements in the baseline forecast. The rate forecast, and in turn the revenue requirements, are bifurcated between commodity rates, which estimate the costs for the procurement of energy, and Utility Distribution Company (UDC) costs, which estimate the costs for the delivery of energy and encompass costs not attributable to the procurement of energy. The combination of the commodity revenue requirement and the UDC revenue requirement constitute the total estimated revenue requirement for ratepayers. For the purposes of this Phase I report, the SDG&E UDC refers to the costs for SDG&E to continue to serve the load within the City. The term MEU refers to the City-owned municipal electric utility that would own specific transmission and distribution assets in the City and provide retail electric service to the citizens and businesses in the City.

To compare costs and the revenue requirement for the delivery of energy specifically, the Financial Capacity analysis uses the baseline under the current SDG&E business model and forecasts how these costs would change under an MEU. In both cases (the SDG&E UDC and MEU), the load forecast and commodity revenue requirement are held constant. The feasibility analysis does not anticipate any changes in the energy procurement model for San Diego ratepayers and assumes that SDCP will serve as the default energy supplier for all City customers. While additional analysis could be completed to refine the commodity cost forecast, it does not have a material impact on the high-level results in the Financial Capacity Analysis because the commodity forecast is held constant over the SDG&E UDC and MEU. The Financial Capacity Analysis is intended to focus on the estimated differential of SDG&E UDC costs (i.e., transmission and distribution), inclusive of any costs associated with implementing the MEU.

To create an estimated forecast for costs for the MEU, the Financial Capacity Analysis bifurcates these costs into Projected Operating Expenses and Non-Operating Expenses. Projected Operating Expenses include high-level estimates of: i) transmission access charges (TAC); ii) operations, maintenance, administration, and general expenses (O&M/A&G); iii) non-bypassable regulatory charges; iv) public benefit charges; and v) payments in lieu of franchise fees and undergrounding. Projected Non-Operating expenses include high-level estimates of: i) debt service and financing costs for the financing requirements, including the purchase price, start-up costs, severance costs, financial reserves, and future capital investment requirements; ii) annual pay-as-you-go capital investments funded from annual rate revenues (as opposed to bonds); and iii) additional annual revenue requirements for financial reserves, liquidity, and credit requirements. The combination of the Projected Expenses and the Non-Operating Expenses is used to derive the transmission and distribution revenue requirement under the MEU and then is compared to the forecasted baseline SDG&E UDC expenses to estimate the cost/benefit of the respective approaches.

This methodology is summarized in Figure 8-1 below.

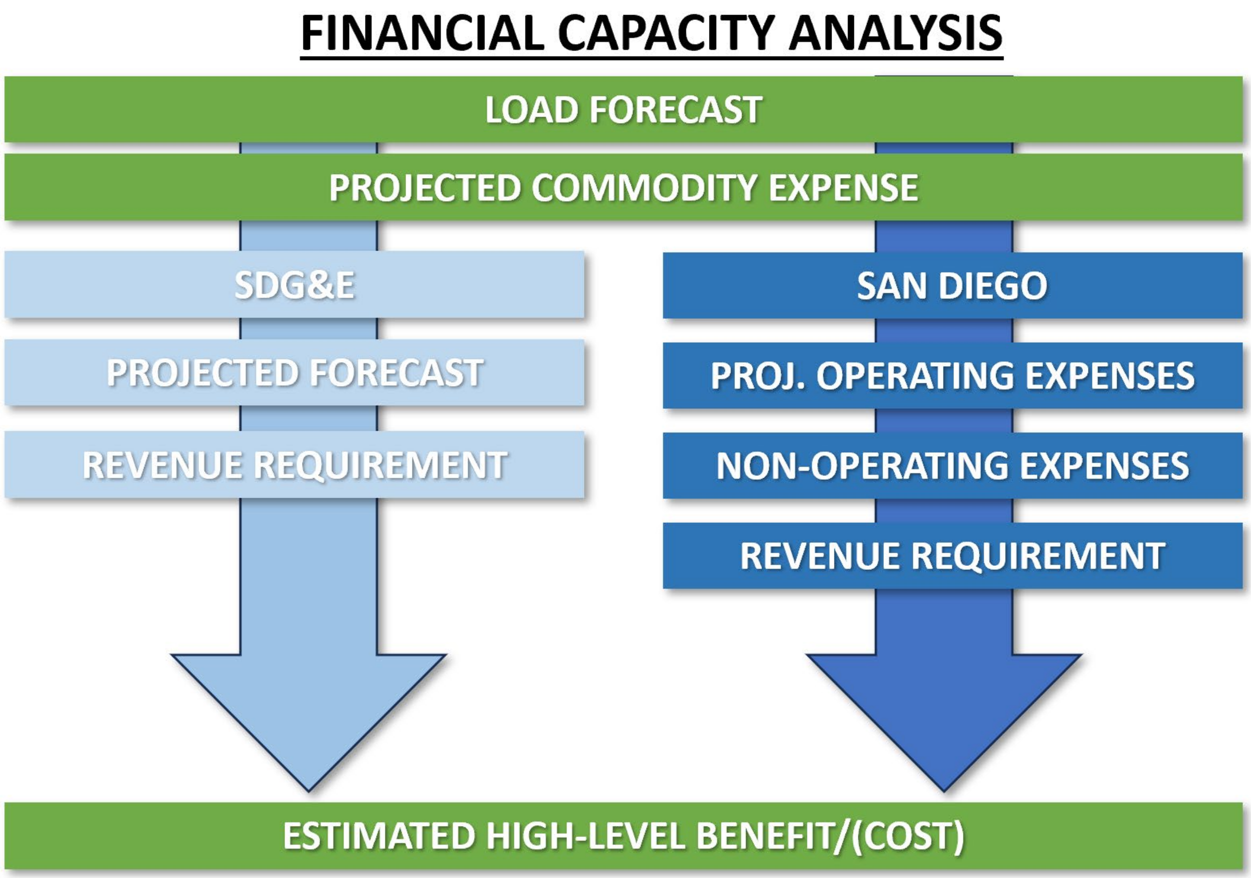


Figure 8-1. Cost Benefit Comparison

Financial Alternatives

There are multiple financial alternatives that are available to this analysis given the number of underlying assumptions. Each of these assumptions can be tested in whole or in combination to assess the impact of different market, cost, revenue, and growth assumptions, among other factors. The single biggest assumption surrounds the assumed purchase price of the assets the City must acquire to form the MEU. This assumption is a function of what assets are being purchased and, importantly, what transmission assets are necessary to effectively deliver the energy to ratepayers. This division of assumed assets further impacts severance, operations and maintenance, and additional capital investment requirements, among other costs.

Not only are the underlying assets a key driver in the potential acquisition cost, the appropriate underlying methodology for valuing those assets is crucial as well. The Financial Capacity Analysis looks at two different valuation methodologies to derive a high-level acquisition cost or purchase price: OCLD and RCNLD. As the titles suggest, OCLD is the value of the existing assets today whereas RCNLD is at the cost of reproducing the existing assets in today's market.

The reason to consider both methodologies is because they serve as potential bookends of where a acquisition price should likely land. OCLD is the lower cost and most advantageous to the purchaser. It is equally reasonable to assume that a prudent seller would not accept OCLD in isolation and would likely look for a multiple of OCLD, such as 1.2x to 1.5x. In contrast, RCNLD is the highest cost and most advantageous for the seller. It is likely that a prudent purchaser would not accept RCNLD. As such, these two methodologies create a reasonable range where the actual acquisition price is likely somewhere in the middle (see Key Considerations herein).

The Financial Capacity Analysis projects costs over a 30-year period, assuming 2023 as a base year. Revenues and expenditures are inflated into Year of Expenditure dollars (YOE$) from 2023. It is also recognized that the actual execution of the MEU would take many years, if not decades, to develop. The actual costs would need to be further inflated until such a time as the MEU was established. What the current cost benefit analysis does is assume that the execution of the business strategy would begin in Year 1 and continue through Year 30, also recognizing that the ultimate start date would be dependent on a number of different factors. The Financial Capacity Analysis is a review of where the City would stand today over a 30-year horizon, understanding that costs will likely be higher the longer it takes to implement and that costs will also extend beyond the 30-year horizon as the MEU continues. To illustrate the high-level benefits or costs, this report focuses on the first 30 years of the MEU because this is the term of the initial acquisition financing, recognizing that the later years in any projection have less certainty given the passage of time and the possibility of unforeseen events and potentially changing circumstances.

Assumptions

The Financial Capacity Analysis is highly driven by assumptions including, but not limited to, those listed above. In connection with this Phase I report, these assumptions are at a high level and are intended to help frame the general financial feasibility of the establishment of an MEU. Additional financial analysis and diligence will be necessary to continue to evaluate the underlying financial feasibility, including the refinement of any key drivers or assumptions that may otherwise impact the overall feasibility of the effort as a financial matter.

It is also worth noting that this report includes forward-looking statements and financial projections that may or may not be accurate depending upon the ultimate validity of any of the underlying assumptions. The list of assumptions, considerations, and findings contained herein are not intended nor represented to be exhaustive or all inclusive, and additional work may be necessary to expand on the preliminary findings of the report, including additional detailed analysis to confirm the preliminary cost and revenue estimates, and expanded analysis should additional policy, operational, and financial assumptions, information, or considerations merit further study and/or revision.

Expense Assumptions

Once the range of a potential purchase price is derived, additional costs are added to the purchase price to estimate the overall financing requirements or how much the MEU will need to finance before operations begin. These assumptions include: i) severance costs, ii) start-up costs, iii) financing costs, and iv) reserve costs. Key financing and expense assumptions include:

- **Severance costs are outlined in Section 6 of this report and are intended to address the potential cost of separating the systems between SDG&E and an MEU.** The ultimate severance costs are dependent on what assets may or may not be included in the MEU; as such, any estimate is highly variable. It is anticipated that additional analysis of the potential severance costs will be completed later. Subject to any changes that may result from additional analysis and/or diligence, the Financial Capacity Analysis assumes severance costs in the $500 million to $1 billion range.
- **Start-up costs reflect the significant need for upfront investment in resources to stand up an MEU.** These costs are significant and include high-level estimates of: i) regulatory costs, ii) professional services, iii) operations, iv) equipment, iv) vehicles, and v) IT. These costs are separate and apart from annual ongoing costs, though many are in the same business functions, and are intended to provide for upfront investments that are necessary to operate the MEU efficiently and safely from its inception. These start-up costs may also include a termination payment under the existing Franchise Agreement, which is also variable depending on the timing of any termination. While these high-level estimates are included in the Financial Capacity Analysis, additional details, including both cost estimates and any additional business functions that may be necessary, would be evaluated further in Phase II of the Study. It is currently estimated that start-up costs for the MEU are $300 million.
- **Financing costs are attributable to the upfront and ongoing debt financing that the MEU will require.** It is assumed that there will be substantial upfront financing as well as ongoing financing needs for ongoing capital investments. Financing is certainly common in the municipal sector, and it is assumed that the financing structure of the enterprise will be consistent with general municipal utility costs and requirements. It is assumed that financing costs attributable to the issuance of bonds will be 2% of the total financing requirements.
- **Financial reserves are also considered in the context of the upfront financing requirements as well as any ongoing annual contributions to reserves.** Consistent with best practices of a municipal utility enterprise, it is assumed that any MEU would provide ample financial reserves for unforeseen events, rate stabilization, working capital, liquidity, and other operating requirements. It is worth noting that the ultimate level of and policies governing financial reserves would be further described in Phase II of the Study or later, including, but not limited to, polices governing reserve levels, funding requirements, eligible use, and replenishment requirements. The Financial Capacity Analysis assumes targeted reserves of 90 days of working capital and 20% of annual MEU operating costs for additional liquidity.

Once the financing requirements are derived, the Financial Capacity Analysis estimates high-level annual Projected Operating Expenses, including but not limited to:

- **Transmission Access Charge is included based on the total megawatt hours (MWh) delivered with an offset for any balancing account adjustment, reflecting the potential for incremental transmission assets in the MEU.** It is currently estimated that TAC costs could be in the $100 million to $200 million range annually. The level of the TAC and any adjustment is highly dependent on what SDG&E assets may or may not be included in the MEU and is subject to further refinement.
- **Operations, Maintenance, Administration, and General expenses include annual estimates for both the transmission and distribution assets for system operations, planning, overhead,**

undergrounding, substations, and other annual expenses. Additional expenses include metering, customer service, IT, and regulatory compliance. It is currently estimated that the annual O&M/A&G costs for the MEU could be in the $400 million to $600 million range. These high-level estimates are subject to adjustment and refinement in connection with Phase II of the Study.

- **Non-bypassable regulatory charges represent annual obligations that are potentially continuing to occur for the MEU.** These costs, including their level and applicability, are subject to review and ultimately regulatory oversight, but it is likely that there will be some level of non-bypassable charges (NBC) that the MEU will need to consider. While the level and applicability of any such charges would be determined in the future, potential examples might include charges relating to nuclear do-commissioning and/or wildfire safety. In California, these costs are typically 2 to 3 cents per kWh and go toward funding energy efficiency, low-income customer assistance, and other related programs. It is assumed that these costs will be in the 5% to 10% range of the annual MEU revenue requirement, and that these costs will need to be further refined in connection with Phase II of the Study (see Key Considerations).
- **Public benefits costs are assumed to be statutorily imposed charges that benefit the public typically through low income, energy efficiency, or other public interest programs.** It is assumed that these costs will be in the 2% to 5% range of the MEU annual revenue requirement, and that these costs will need to be further refined in connection with Phase II of the Study.
- **The City currently receives franchise fees and the undergrounding surcharge.** There are restrictions on what can and cannot be done with these revenues, notably undergrounding, but the Financial Capacity Analysis assumes that the City is benefiting from fees, taxes, and surcharges that the City is currently receiving under the SDG&E business model. To keep the City revenue neutral, it is assumed that some form of payment would need to be made to the City from the MEU to replace what might otherwise be lost revenue, regardless of any restrictions on use. There are certainly additional policy and legal considerations on how such a payment might be structured and for what purpose, recognizing that there are a host of different regulations and legal requirements in California that would need to be reviewed and satisfied. Even if how such a fee is structured or sized is ultimately determined in the future, the Financial Capacity Analysis captured this cashflow obligation within the MEU to keep the City financially neutral. It is assumed that these costs will be in the 5% to 10% range of the annual MEU revenue requirement, and that these costs will need to be further refined in connection with Phase II of the Study (see Key Considerations).

Once the Projected Operating Expenses are derived, the Financial Capacity Analysis estimates high-level annual Non-Operating Expenses for the MEU, including but not limited to:

- **Annual debt service on the aggregate purchase price and financing requirements is estimated.** The aggregate financing requirements include the purchase price, severance, start-up costs, and initial reserve costs. It is assumed that these costs will be financed over a period of 30 years accessing both the taxable and tax-exempt municipal markets, consistent with the terms of utility revenue bonds typically and regularly financed in the municipal sector. For the purposes of this Phase I report, long-term taxable rates are assumed to average around 5% and tax-exempt rates around 4%.
- **Annual debt service on the future capital investment requirements is estimated.** The requirements are for both transmission and distribution assets and include new plant additions to accommodate future load growth and required investments based on asset retirement (see Section 7). It is assumed that these costs will be financed over a period of 30 years, accessing the tax-exempt municipal market at interest rates around 4%.

- **Annual rate-funded capital investment requirements are also estimated.** Based on the total capital investment requirements, it is assumed that a portion of these capital requirements are financed as noted above, and a portion of these annual requirements are paid from annual rate revenue for the MEU on a "pay-as-you-go" basis. The Financial Capacity Analysis assumes that 50% of the annual capital investment requirements are financed and the balance is funded with annual rate revenue. As revenues increase over time, it is further assumed that the MEU would increase the percentage of rate-funded capital.
- **The Financial Capacity Analysis funds annual liquidity needs, including any additional funds necessary to meet reserve requirements and/or any credit requirements to support municipal financing.** As noted above, targeted reserve policies will be subject to future review and analysis, but the Financial Capacity Analysis recognizes that reserve requirements will change and grow over time as operating costs increase as well. To the extent that additional annual revenues are necessary to meet targeted reserve levels for working capital and/or liquidity, these revenues are shown as an annual Non-Operating Expense.

Revenue Assumptions

MEU revenues are assumed to be derived from retail rates and charges from ratepayers by rate class. For SDG&E, rate classes in the Financial Capacity Analysis include: i) residential, ii) small commercial, iii) medium and large commercial, iv) industrial, v) agricultural, and vi) lighting. Based on the rate class, individual rates for commodity and delivery expenses are applied to the load forecast to generate an aggregate revenue requirement. The initial revenue requirement for the SDG&E UDC is assumed to be in the $1.5 billion to $1.6 billion range.

For the MEU, revenues are also driven by the aggregate revenue requirement and are assumed to be recovered from rates and charges from City ratepayers. The aggregate revenue requirement is derived from the combination of the projected commodity requirements and the projected MEU Operating Expenses plus the projected Non-Operating expenses. As noted herein, the projected commodity requirements, and in turn revenue requirement for power supply, are held constant between the SDG&E UDC and the MEU.

While both business models assume that user-based fees in the form of rates and charges are the basis of funding the estimated expenses, the Financial Capacity Analysis does not make an allocation among individual rate classes for the MEU. This type of allocation would be subject to a detailed COS study that would distribute the overall revenue requirement across the individual ratepayer classes based on cost allocation and public policy goals of the City.

High-Level Financial Capacity Results

Recognizing that the projected commodity expenses for energy procurement are held constant between the respective business models, the high-level estimated cost/benefit is determined by comparing the SDG&E UDC revenue requirement to the revenue requirement under the MEU which includes both the projected Operating Expenses and the projected Non-Operating Expenses.

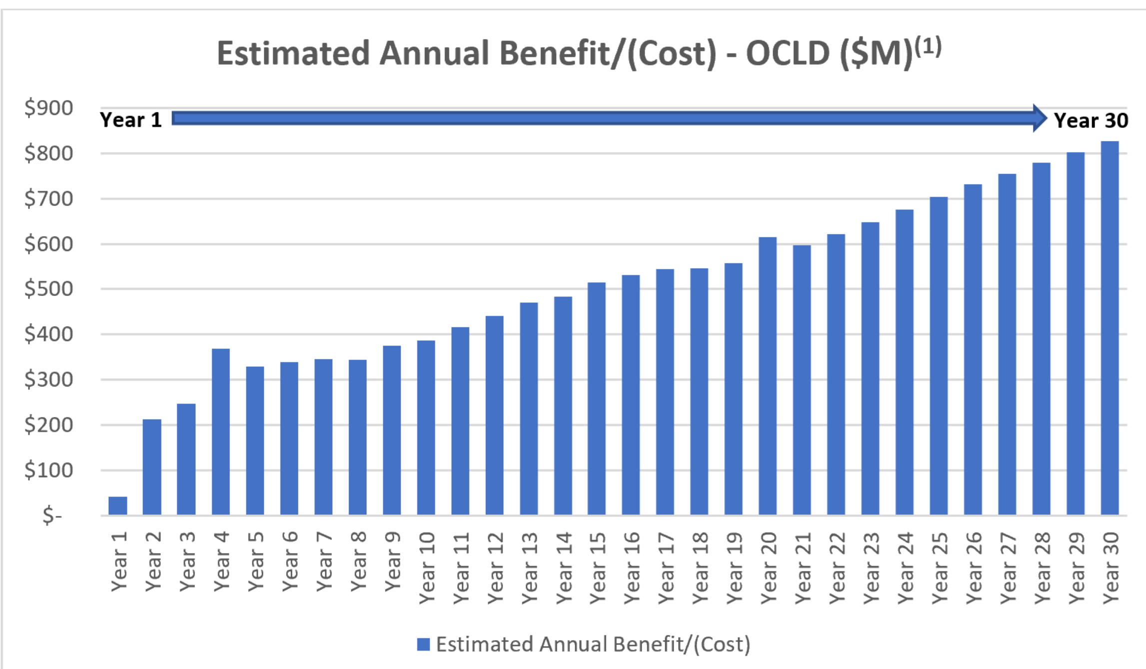
As noted herein, any number, if not most, of the underlying assumptions can have an impact on the overall financial capacity and preliminary financial results. However, by holding assumptions on the underlying load forecast constant along with the underlying expense drivers, it is possible to frame the impact of different assumptions for the purchase price and its corresponding impact on the estimated cost/benefit.

This range of alternatives forms the basis for evaluating the potential financial feasibility on a high level of the MEU.

One of the key assumptions in the purchase price is the underlying valuation methodology. There is a material and significant range in the projected purchase price between OCLD and RCNLD. The Financial Capacity Analysis assumes a range of $2.5 billion OCLD to $6.2 billion RCNLD for the purchase price outside of additional costs for severance, start-up costs, and financial reserves, which could add an additional $1.0 billion to $1.5 billion to the upfront financing requirement. These forecasts are high level and subject to additional analysis in connection with Phase II of the Study, not the least of which is confirmation of what assets are specifically included in any potential purchase. At the same time, the ranges of costs are instructive and illustrative for the purposes of projecting preliminary financial results and determining at a high level whether such a strategy may make financial sense, subject to any changes or additional analysis.

The annual cost or benefit in YOE$ for both OCLD and RCNLD purchase prices is estimated to provide a range of potential outcomes. It should be noted that these outcomes are preliminary and subject to change for any number of reasons, including assumptions and/or factors that may be unknown or unforeseen at this time. While these results present a range of outcomes, they are not the only outcomes that are feasible or potential, and additional outcomes outside of this presented range are possible. Any change to the underlying assumptions could result in financial results that are materially different and fall outside of this range of outcomes, and actual results will vary.

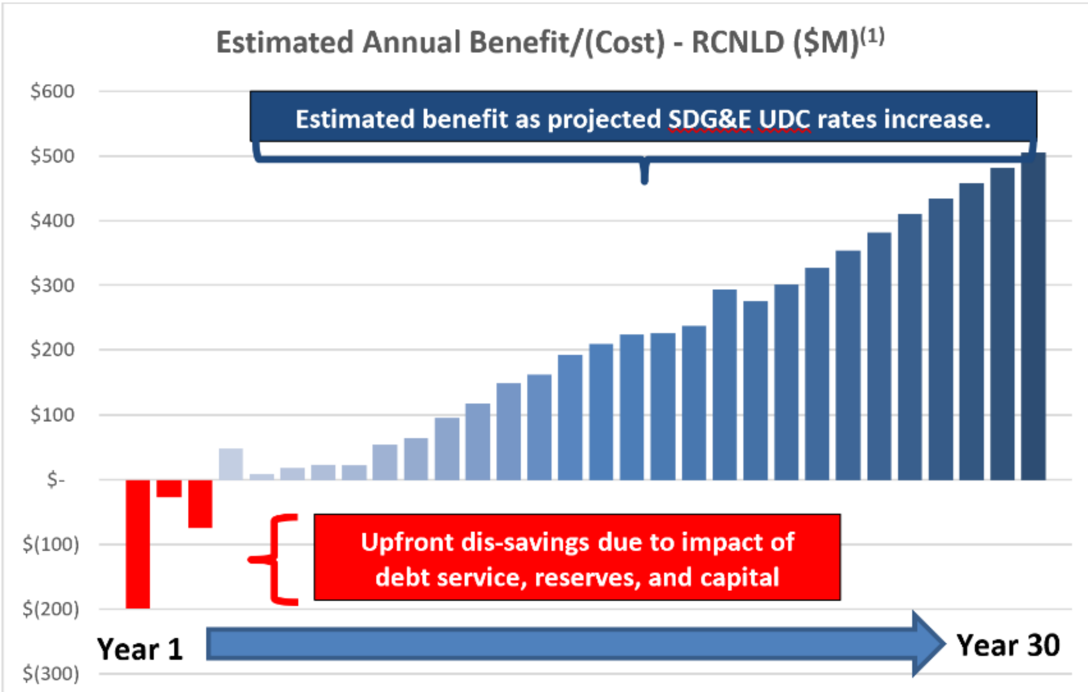
The estimated benefit of the MEU over 30 years, inclusive of the assumptions herein and assuming a purchase price of approximately $2.5 billion (OCLD in 2023 dollars), is outlined in Figure 8-2. The 30-year timeframe is intended to be consistent with the term of the initial acquisition financing but may also be less certain over time given the increasingly extended timeframe.



(1) For illustration purposes only; Actual Results will vary.

Figure 8-2. Estimated Annual Benefit/(Cost) at OCLD

Assuming a purchase price of approximately $6 billion (RCNLD in 2023) and recognizing all the assumptions above, the estimated annual benefit over a period of 30 years is outlined in Figure 8-3.



1. For illustration purposes only; Actual Results will vary.

Figure 8-3. Annual Benefit/(Cost) Illustration at RCNLD

Summary of Preliminary Economics

While the High-Level Financial Capacity Results illustrate preliminary financial feasibility and ample potential savings on an absolute dollar basis, it is also important to look at these estimated results on a cumulative and relative basis (see Key Considerations). The cumulative savings capture the impact of upfront costs, if any, to determine how long it may take to recover any upfront costs, especially as debt service for the initial acquisition financing comes online. The relative costs are also important given the size of the overall enterprise. While the illustrative high-level savings may be large, they must also be evaluated in the context of the projected SDG&E UDC revenue requirement to have some sense of the relative savings.

The relative savings are also important because they are being shown on a strictly financial basis and are not risk weighted. As discussed herein, there are significant policy, business, organizational, legal, regulatory, and operational considerations, among other factors, that will be weighted in the context of overall feasibility. Both quantitative and qualitative considerations will need to be evaluated for the MEU.

A summary of the preliminary economics showing the cumulative benefit of OCLD and RCNLD for the 10-, 20-, and 30-year timeframes is provided in Table 8-1.

Table 8-1
Summary of Preliminary Economics ($M)(1)

	Year 10	Year 20	Year 30
Est. Cumulative SDG&E UDC Revenue Requirement ($)	$22,000	$55,000	$100,000
OCLD Cumulative Benefit ($)	$3,000	$8,000	$15,000
OCLD Cumulative Benefit (%)	13% to 14%	14% to 15%	14% to 15%
RCNLD Cumulative Benefit ($)	($60)	$2,000	$6,000
RCNLD Cumulative Benefit (%)	0%	3% to 4%	5% to 6%

(1) For illustration purposes only; Actual Results will vary.

Key Considerations

There are key considerations from the Financial Capacity Analysis high-level results that should be evaluated and integrated into any conclusions in order to provide additional context as to the overall feasibility of the MEU. These considerations are both quantitative and qualitative and can have a material impact on the results, and even the conclusions thereon. These considerations include, but are not limited to, the following:

Load Forecast

One of the key drivers is the assumptions for future load growth within the City. While this is a particularly important assumption on the power supply or commodity side of the business, it also impacts transmission and distribution in terms of the amount of energy that needs to be delivered and the corresponding impacts on O&M costs as well as future capital investment requirements. The Financial Capacity Analysis assumes that there are approximately 700,000 customers within the City, or 45% to 50% of the existing SDG&E customers. These customers are further projected to have modest growth of under 1% annually. As the City contemplates housing policy and corresponding targets, job creation, and other economic trends, the City can continue to evaluate the long-term projection for population and customer growth within the region.

In terms of usage, the load forecast recognizes that there will be impacts of both increased electrification and increased energy efficiency and DER. Electrification will increase due to increased electric products, whether vehicles, homes, or appliances, as well as policy or legislated mandates that may curb the use of natural gas as an energy source for such products. Offsetting this increased usage will be the ability for consumers to install more efficient products and the ability to generate their own electricity through locally sited generation resources, such as solar and battery storage. The Financial Capacity Analysis assumes that these two dynamics will in large part offset each other; however, there is some incremental and modest assumed growth in energy usage per customer (See Section 6).

When combining assumed growth in customers and projected net usage per customer, the Financial Capacity Analysis assumes less than 1% annual growth in net energy sales. While there is no reason to believe that this forecast is unreasonable as a high-level assumption, the point remains that the load forecast is a material driver that impacts other components of the analysis and, in turn, the overall financial results.

Rate Forecast

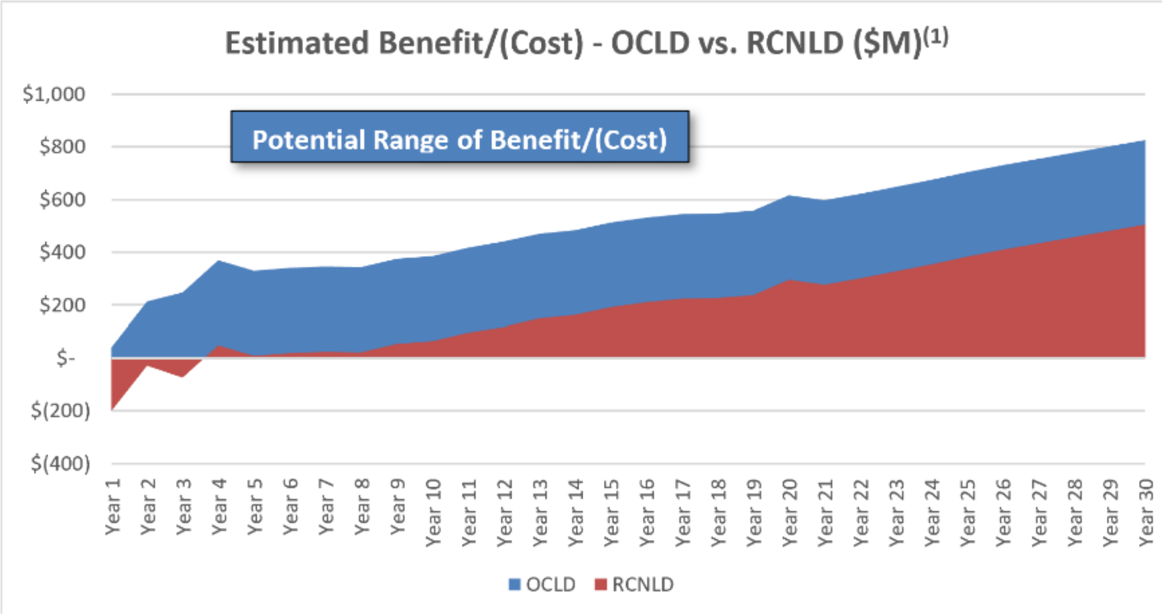
The forecasted growth in the underlying utility rates is also germane to the projected cost/benefit of any municipalization effort. While forecasted commodity rates are less important in the context of the Financial Capacity Analysis since they are equally applied to both business models, forecasted growth in the SDG&E UDC rates is certainly directly relevant to the overall cost benefit estimation of the MEU. The Financial Capacity Analysis assumes SDG&E UDC rates will remain relatively flat over the next year but based on Post Test Year Ratemaking Workpapers – Revised (Exhibit SDG&E 45), it is assumed that SDG&E UDC rates will grow between approximately 8% and 12% annually over the 2025 to 2027 timeframe. While this level of rate increases is subject to regulatory oversight and approval, it is consistent with historic SDG&E rate increases of approximately 7% to 15% since 2020. In contrast, long-term growth rates beyond 2027 in the Financial Capacity Analysis are assumed to be more modest at 3% annually. To the extent that future SDG&E UDC rate increases are different than those projected, especially if they were materially lower, then the benefit/(cost) estimates would also be impacted.

Purchase Price

As noted herein, a key driver in the overall economics of any municipalization is the assumed purchase price or acquisition cost. The Financial Capacity Analysis has evaluated a range of potential prices using two market standard approaches, OCLD and RCNLD. The reality, however, is that the purchase price will be determined in no small part based on a negotiated or litigated price. It is of course dependent on the ultimate assets that may be included, but even then, this is still an exchange between a purchaser and a seller, one who may otherwise be reluctant to sell and/or seek a very high price for the assets regardless of any valuation methodology. As previously noted, it is likely that a prudent seller would not accept OCLD, and a prudent purchaser would not accept RCNLD. This means that the purchase price will likely be in the middle of this range, but it is also important to consider the willingness and/or requirement of either party to execute a transaction.

Savings Structure, Timing, and Payback Period

How and when ratepayers might realize financial benefits from an MEU, if any, is also a meaningful consideration. As noted, an MEU will require significant upfront financial and resource investment. While many, if not most, of these costs will be financed, how and when financing comes online will be impactful regarding the timing of any benefit. Provided in Figure 8-4 below is a comparison of the estimated high-level benefit over the next 30 years based on the Financial Alternatives discussed herein. What these results show is that there is a potential cost of the MEU over the initial 3 years. This cost is primarily the result of the impact of debt service from the financing of the acquisition and other respective costs.

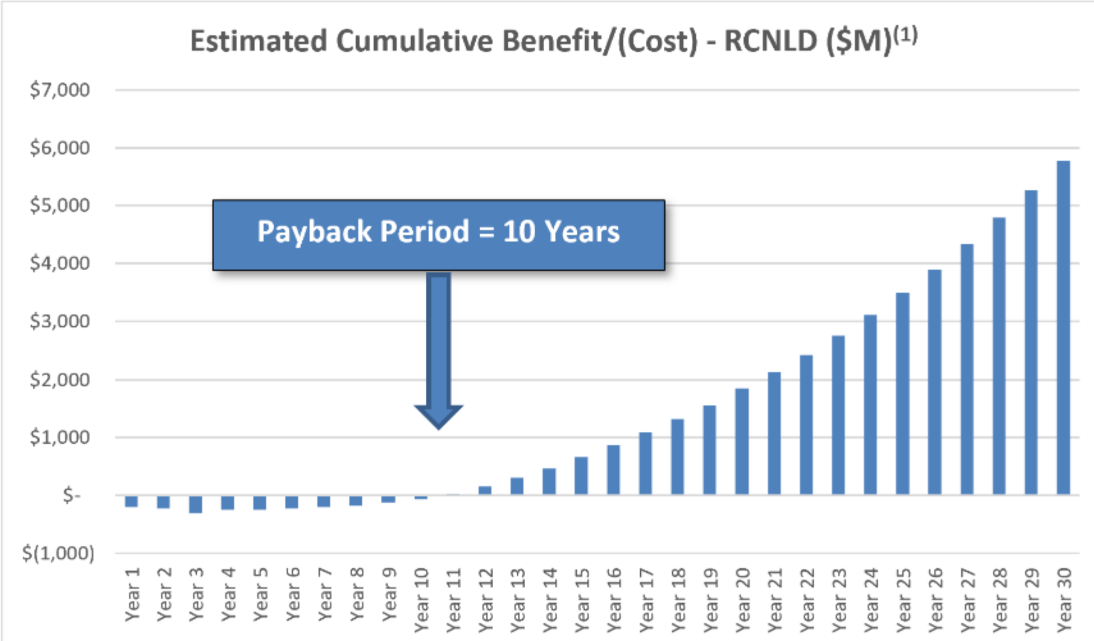


1. For illustration purposes only; Actual Results will vary.

Figure 8-4. Range of Benefit/(Cost)

Depending on the assumptions, including the purchase price, it is not unexpected that there could be some cost for ratepayers associated with the acquisition of the SDG&E assets for some period of time. At the same time, the question as a policy and financial matter is whether these costs can be reasonably expected to be reduced and/or recovered and over what timeframe. This recovery can be viewed as the payback period.

The cumulative costs of the RCNLD alternative are shown below to illustrate the concept and estimate of the payback period. What this illustrative example shows is that a purchase price based on RCNLD, given all the assumptions described herein, could generate a potential payback period of an estimated 10 years. Without a targeted strategy to reduce these costs, it could require a decade to recover the costs incurred in the initial three years. While it is a policy decision of the City, this payback period remains arguably a reasonable term given the expected useful life of the underlying assets, which are assumed to be considerably longer than 10 years, and more importantly, the overall policy objectives that may be driving the acquisition.



1. For illustration purposes only; Actual Results will vary.

Figure 8-5. Payback Period Estimation

It is also worth noting that the size of the upfront financial cost, if any, is dependent on what steps may be taken to mitigate or otherwise reduce these upfront costs. Any reduction in these costs can also reduce the corresponding payback period. As noted, the biggest driver of upfront costs is debt service; however, there are additional factors that also contribute to these annual costs, including any capital investments funded from rate revenue, any financial reserve contributions funded from rate revenue, and any requirement to meet targeted credit metrics associated with financing. The total amount of capital that needs to be financed up front is a key driver in the level of savings or costs (dissavings) in the early years of the MEU. In each of these cases, there are tools that can and should be explored to help mitigate these costs, which include:

- **Reducing the immediate impact of debt service by delaying principal repayment and/or capitalizing interest.** The Financial Capacity Analysis assumes that the initial financing would have some period of interest only and the principal amortization would occur beginning in year 3, for example. Further, it is feasible to capitalize interest over some period of time, whereby the MEU would use financing proceeds to help cover interest expense in the early years of a financing. Both techniques are commonly and widely used in the municipal sector to better align the cost structure with the asset being financed and the timing of debt service with the capacity of the enterprise to help balance affordability for ratepayers. This strategy is also commonly employed when it is expected that there will be long-term benefits that can be used to help offset upfront costs.

- **Financing a greater share of capital investment in the early years that would otherwise be funded with annual rate revenue.** The Financial Capacity Analysis assumes that 50% of annual capital investments for additions and retirements are funded on a pay-as-you-go basis from annual rate revenue. One alternative strategy would be to adjust the percentage of projects in the initial years that are bond financed versus cash funded while also being mindful of any credit requirements.

- **Developing a Financial Reserve Policy.** Rules and procedures for funding financial reserves are typically governed under a formal reserve policy, which is also a best practice among municipal utilities. Reserve targets and balances can be built over time with established targets and metrics. While the Financial Capacity Analysis fully funds reserves from inception, a Financial Reserve Policy could provide incremental flexibility, especially in the first few years of an enterprise, and this strategy could lessen upfront cost pressure as well.

In all these cases, it should be noted that there will always be upfront cost pressure given the size and magnitude of any municipal acquisition and the corresponding need to finance so much upfront capital investment, most of which is not discretionary under the MEU since these costs are primarily attributable to the acquisition price and severance. There are strategies that are commonly used in the municipal sector and can be employed to reduce this cost pressure. How and when these strategies can be utilized, and the usage of any other opportunities, is a function of understanding more specifically the exact nature and scale of the upfront costs; however, it is not simply a strategy in isolation to reduce upfront rates hoping to extend the potential payback period. It is likely that a combination of approaches will need to be considered in order to reduce any upfront rate pressure.

Relative Rate Impact

It is also worth noting the magnitude and scale of the overall numbers that are intrinsic to the Financial Capacity Analysis (see Summary of Preliminary Economics). Revenue requirements are in the billions of dollars. Even when costs or revenues are discussed in the context of tens or hundreds of millions, the impacts on a percentage basis are more tempered. This means that while projected savings are potentially large on an absolute basis, the relative impact on rates and charges is muted. Even in the later years of the Financial Capacity Analysis illustrated herein, the relative rate impact on MEU rates is projected to be 5% to 15%, depending on the purchase price. Further, this financial impact is only on one portion of the consumers' bill since commodity charges, including those by SDCP, also drive the ultimate ratepayer cost, meaning that a 10% MEU savings does not equate to a 10% savings on the overall utility bill. This is not to say that incremental percentage savings are immaterial to ratepayers, but to note that absolute numbers can be used to sway or otherwise frame a discourse, even when the absolute numbers should rightfully be put in the context of the overall magnitude of the enterprise.

Non-bypassable Charges and Payments in Lieu of Franchise Fees and Surcharges

As noted herein, there are likely to be some statutory or regulatory charges that the MEU will need to consider (see Expense Assumptions). These charges are to be determined and some may be subject to regulatory review. Some of these charges may be state imposed and some may be governed by local policy. Most, if not all, will be for specific purposes, and how these charges are sized, administered, and applied will be subject to further review, including what restrictions or requirements may exist. Similarly, how any payments or charges are structured and sized to maintain revenue neutrality for the City will also need to be evaluated. There may be additional policy, legal, and/or business implications relating to the potential use of these funds. This is not an unusual set of considerations in California where many cities have municipal utilities.

There may also be tangential benefits that can be captured. To the extent that the City has any greater control on the application or use of funds, such as undergrounding, this heightened local control may offer policy benefits outside of financial ones. In each case, the point is that any additional charges, whether state or locally imposed, will need to consider their sizing and eligible use in connection with the overall enterprise. While the Financial Capacity Analysis is intended to capture the estimated cost of such programs, restrictions may exist as to the application of any funds derived from these charges.

Financing Execution and Credit Metrics

Another consideration worth highlighting is the magnitude of the financing requirements associated with a potential acquisition of the SDG&E assets by the City. Similar to the rate impacts, the MEU will require financing in the billions of dollars, with the ultimate purchase price governing the exact value. There is certainly ample capacity and investor demand to support multi-billion financings in the municipal market. At the same time, execution strategy and implementation are more acute with larger transactions. This is not to say that execution risk should unto itself be a driver of proceeding or not, and in fact, the successful execution of the embedded required financing may be more of a question of incremental cost than of feasibility. Still, the Financial Capacity Analysis recognizes that there will be key credit metrics that must be considered to best position the enterprise for successful market access and financing results.

One key driver for the financing and expected financing costs will be the credit ratings of any MEU- or City-issued bonds. The Financial Capacity Analysis makes no underlying assumptions about what the credit rating will be for any bond financing; however, the Financial Capacity Analysis has been structured to incorporate key credit metrics including liquidity (financial reserves noted herein) and debt service coverage, depicting the sufficiency of cash flow to support debt service on an ongoing basis.

The Debt Service Coverage Ratio analysis (DSCR) evaluates the ability of the Net Operating Surplus (Operating Revenues less Operating Expenses) to cover projected annual debt service. Typically, institutional investors and the credit rating agencies would expect the Net Operating Surplus to be in excess of the annual debt service. While the legal requirement can often be in the 1.20x range (meaning Net Operating Surplus Revenues must meet or exceed 1.20x debt service), it is not unusual for municipal utility credits to demonstrate higher debt service coverage in the 1.25x to 2.00x as a policy matter, with higher coverage typically supporting higher credit ratings. The Financial Capacity Analysis targets 1.50x DSCR as a financial target. While impacted by a number of credit variables, it is common for municipal utility bonds to carry credit ratings in the "A" category with DSCR in the 1.50x range. Figure 8.6 provides the results of the DSCR analysis conducted for the Financial Capacity Analysis.

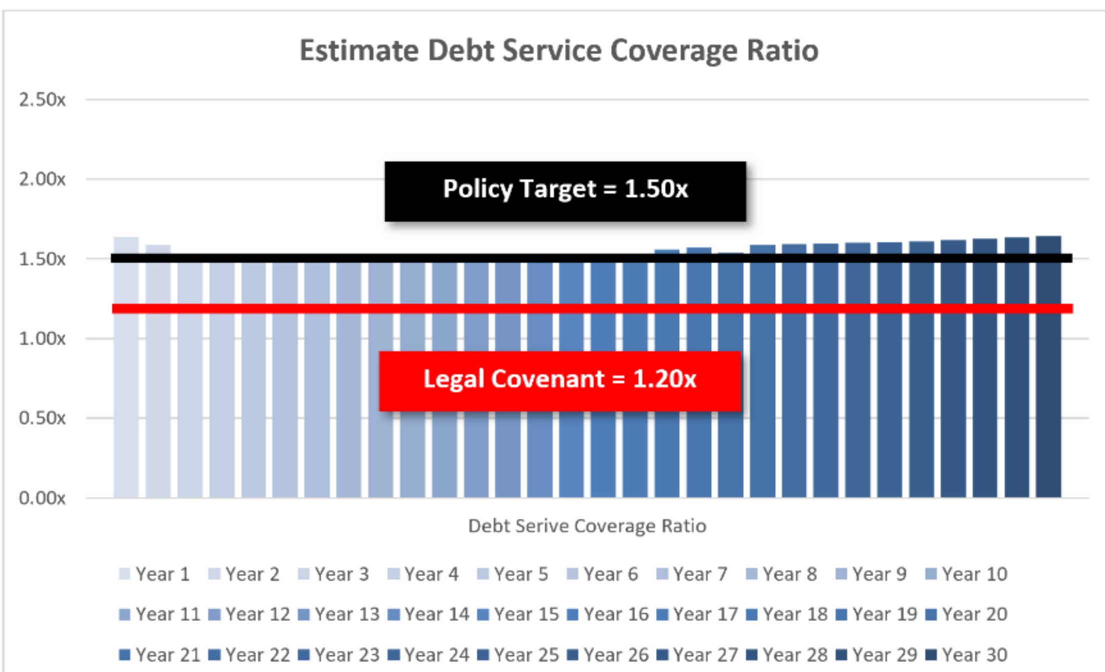


Figure 8-6. Debt Service Coverage

Section 9
RISKS, RISK MITIGATION, AND OTHER CONSIDERATIONS

This section provides a summary of the types of risk, potential risk mitigation strategies, and other considerations for the City in its decision to form an MEU. The risk management function of an MEU for the City should be relatively large and independent of other business units. This section presents a high-level overview of this function; a more thorough and detailed review and analysis of the risks associated with the MEU will need to be addressed later in the municipalization process.

In general, the risks associated with operating a large municipal utility can be organized into the following categories.

Types of Risk

Commodity Risk

The commodity risk of the MEU would generally reside with SDCP (the assumed power supply provider for all load in the City). It is important to note that even though SDCP would be responsible for all commodity (i.e., electric power), the risks for the MEU would not be entirely eliminated. The risk management team of the MEU would need to, at a minimum, review and monitor the risk management efforts of SDCP on a monthly basis. The MEU would ultimately be responsible for the reliability of power delivery, and commodity delivery is critical to that mission.

Counterparty Risk

Counterparty risk management relates to the counterparty trades and hedges related to energy supply, whether gas or electricity, as well as any financial instruments utilized by the utility. Again, the majority of the counterparty risk would be associated with power supply (SDCP); however, the MEU would bear some responsibility for managing these risks as well.

Third-Party Contract Risk

Third-party contract risk deals with risks associated with contracting with outside vendors such as construction contractors, vegetation management (e.g., tree trimming), SDCP, etc. The risk management function of the MEU would need to develop controls and standards for mitigating such risks.

Operational/Reliability Risk

Operational risk is related to regulatory risk, safety, and reliability. The MEU's risk management function would be required to adhere to the risk management standards required by NERC (see Appendix A). Regulatory risk refers to the risks associated with noncompliance with NERC standards, which can result in expensive fees and fines.

In general, safety and reliability are the two most important functions of an MEU. Providing power safely, affordably, and reliably are core functions of any MEU. Safety risks should be managed by the risk management function within the MEU in cooperation with a dedicated, professional safety function.

Reliability risks should be managed by the risk management function in cooperation with a dedicated, professional operations function.

It is important to note that deficiencies in safety and reliability inevitably lead to many other risks including, but not limited to, political risk for political leaders and reputational and financial risk for the MEU and the City, among others.

Financial Risk

The development and execution of an MEU is complex, not only operationally and administratively, but also financially. The biggest risk financially would be whether MEU can deliver energy to its ratepayers in a cost-effective fashion. There are significant foreseeable challenges as well as invariable unforeseeable events and circumstances that will impact the ultimate financial cost of this approach. Factors include, but are not limited to, the purchase price, start-up costs, transition costs, operating costs, capital investment requirements, interest rates, and market conditions. Each of these variables could and would impact the financial cost of the program. How costs and potential liabilities are identified and managed over time is a key consideration.

One measurement of a cost-effective approach is a comparison to what might be reasonably expected under the current SDG&E UDC business model (see Section 8 – Financial Analysis and Considerations). As discussed, there are meaningful variables that will determine what the ultimate cost comparison may look like, and the true measure of relative cost would likely not be fully known until the future, when one can look back at the actual financial results. The financial analysis herein is theoretical based on a number of assumptions, and while there is no reason to believe that the conclusions are not reasonable, the financial risk is that the projected results based on the assumptions made today will not be consistent with, or may otherwise be materially different from, the actual financial results in the future.

Regardless of what the comparison may be to the current business model, it is important to note that future costs could be higher. Market, regulatory, and/or policy decisions could impact future operating costs and capital investment requirements. All these costs could impact the customer bill for the delivery of energy, potentially in an environment of increased demand due to electrification goals and the potential limit of natural gas as an energy resource. Macroeconomic factors or local decision making at the policy level may limit the ability of the MEU to recover its costs through rates. Cost recovery may be over an extended period of time. How the MEU chooses to manage these cost exposures and corresponding risks would drive the long-term cost effectiveness of the approach.

Risk mitigation in this context derives from management's approach to addressing the embedded operating and capital risks associated with managing any large-scale power enterprise. While significant and material risk associated with power supply and energy procurement may continue to reside with the CCA provider (SDCP), MEU would still carry ample risk that would need to be proactively managed over time. From a financial perspective, the risk would be whether the MEU could maintain affordability for ratepayers while meeting the operational and capital requirements necessary to deliver energy to its customers.

One key component of risk management would be the development and execution of key policies, protocols, and procedures for the enterprise. These efforts should include long-term operating forecasts; the capital improvement plan; financial reserve policies; rate setting policies; debt management policies; investment management policies; credit strategies; key performance indicators tracking and evaluation; balance sheet management strategies; and Strengths, Weaknesses, Opportunities, and Threats (SWOT) analyses, among others. Each of these operating and capital components of the MEU would take considerable effort over time not only in their initial development, but also in monitoring and evolving these policies and procedures as circumstances warrant and changes occur. Financial risk management is very much an organic and ongoing requirement that would need significant resources and prioritization within the organization to be successful.

Communicating the impacts and importance of these policies and procedures with stakeholders and decision makers is an important component of overall risk management as well, including financial risk management. It would always be important for MEU management, staff, and the organization as a whole to have clear direction from the policymakers to establish guidelines and procedures for managing risk. Establishing and maintaining the political will to make necessary and informed financial decisions, which may sometimes be politically challenging or require navigating competing objectives, to support the long-term financial health of the MEU would be equally critical in managing long-term financial risk.

Section 10
TIMING AND PROCESS

Municipalization Process Maps

The City has requested the development of a series of process maps to guide its efforts to municipalize the existing SDG&E owned utility systems within the City. A series of six process maps, which are provided below, are meant to provide an overview of the various analyses, decision points, and feedback loops inherent in the City's municipalization decision. The beginning point for the process maps is the conclusion of the "Phase I" activities, which is the purpose of this report and related presentation materials. Each process map consists of two or more horizontal "swim lanes," which are assigned to an entity or entities and describe the activities and the responsibilities of those entities within the lane. The timeline shown for each process was estimated based on the professional experience of the NewGen Team, as well as input from the City.

The process maps include a definitive beginning and end point for each phase and element of the Study, which may or may not lead to the purchase of the utility (SDG&E) assets and subsequent MEU operations. Along the way, there are several processes, subprocesses (and optional subprocesses), documents, data requirements, and decision points required or expected of each entity within its specific lane. Each decision point is posed as a question for the entity within that lane. Subsequent positive responses to each question result in moving forward to the next identified process, subprocess, or document. If the question is answered negatively, the result is either a feedback loop to revisit an earlier decision by that entity or termination of the process.

The intent of these process maps is to focus on the City's requirements as it contemplates formation of an MEU. Other entities beyond the City are identified on the process maps; however, their individual decisions may or may not impact those of the City. It is not feasible to describe the endless possibilities for the City's actions as it moves forward with this historic decision, nor is it possible to fully capture all the potential actions of non-City entities, such as SDG&E, the CPUC, or the courts. However, this mapping process defines and narrows the known elements to a municipalization effort and is designed to assist the City in its strategic efforts to potentially own and operate an MEU.

Six individual process maps were created for the City for this effort; however, they all originate from the detailed map entitled "San Diego Public Power Process" (Figure 10-2). This "primary process map" includes the currently known or expected elements associated with a municipalization process and the primary responsible parties in each lane (the City, SDG&E, Jurisdictions/Regulatory Agencies, and others). The timeline shown in Figure 10-2 begins with the start of Phase II activities (In-Depth Analysis of System/Community Support) and ends with the Operational Readiness Process that includes Begin Utility Operations.

A "summary" process map, titled "San Diego – Critical Path to Municipalization" (Figure 10-1) selects certain elements from the detailed map to provide a high-level overview of the identified critical elements of the process. Additional subprocess maps (Figures 10-3 through 10-6) provide further detail for the stakeholder engagement, LAFCO, CPUC, and condemnation processes.

A more detailed description of each process and subprocess map is provided later in this section. A legend for the process maps is provided in Appendix B.

Timeline

It should be noted that SDG&E's response to the City's potential municipalization efforts could raise new challenges, including legal and regulatory action, as well as potential political pressure. It is not possible to estimate the timing impacts of SDG&E's anticipated responses to the City's efforts; however, sufficient time has been included in the process maps for the City to complete the necessary analysis, reporting and community involvement, and regulatory and legal processes required for a successful municipalization effort.

The Phase II effort is anticipated to begin in July 2023 (after completion and acceptance of this Phase I report) and end in June 2025 (a two-year process that is consistent with the City's fiscal year). If the City were to move forward, the Phase III effort (shown in Figures 10-1 and 10-2) would be expected to focus on the LAFCO/legal process, which is estimated to begin in July 2025 and conclude in June 2031 (a six-year process). Assuming that the City continues its municipalization efforts at that time, Phase IV focuses on the condemnation process (estimated to begin in July 2031 and conclude in December 2034, a three-and-a-half-year process). If the final court determination is consistent with the City's needs, the City may decide to move forward to purchase the SDG&E assets at that time (which would begin the Operational Readiness Process [Phase V], which in itself is estimated to be a two-year effort).

Critical Path to Municipalization

Figure 10-1 shows the Critical Path to Municipalization for the City. As indicated above, Phase II is expected to begin upon the delivery and presentation to the City of the Phase I report, anticipated in July 2023. The primary result of the Phase II activities is the development of a Municipalization Strategic Plan, the results of which will provide insight to the City and prompt a decision if moving forward with municipalization is warranted. If, upon delivery and review of the Municipalization Strategic Plan, the City chooses not to move forward, the municipalization process concludes at that decision point (resulting in the first "End" icon within the City's lane).

If the City decides to move forward, the next phase in the municipalization process is to apply to the LAFCO for regulatory approval to form a municipal electric utility. The LAFCO process is shown as Phase III in Figures 10-1 and 10-2. (The LAFCO subprocess is described in more detail below and in Figure 10-4.)

A successful LAFCO decision is anticipated to allow the City to gain the "Right of Entry" to SDG&E's data, which will allow the City to further refine its estimates of the asset value to be acquired (defined as a necessary data point in the Data/Analysis lane of the Critical Path process map). A successful LAFCO process is also anticipated to define the beginning of direct negotiations with SDG&E regarding asset acquisition. A non-successful LAFCO application may result in the City deciding to resubmit the application based on any identified deficiencies in its initial application process. See the LAFCO Process discussion for additional details.

Direct negotiations with SDG&E are expected to lead to another decision point by the City to decide if SDG&E can meet the City's defined Municipalization Strategic Plan requirements without acquisition of its assets. If so, the City can decide to end its municipalization effort at that point (which would define the end of the Phase III process). However, if negotiations are not successful, the City can decide to move forward with the condemnation process. The data from the City's access to SDG&E's asset systems is expected to support the development of a "Final Engineering Assessment and Asset Value" report, which would form part of the condemnation subprocess (see Figure 10-6 for additional detail).

The condemnation process is shown in Figures 10-1 and 10-2 as the beginning of the "Phase IV" efforts for municipalization (anticipated to begin July 2031 and conclude 2034). As an option, the City may request that the CPUC determine the value of SDG&E assets the City wants to acquire, similar to the approach taken by the City and County of San Francisco to determine the value of PG&E assets it seeks to acquire. The CPUC subprocess would occur prior to the condemnation process for purposes of the Critical Path process map and is more fully described in its own process map (see Figure 10-5). The conclusion of the CPUC process is another decision point by the City to determine if the determined asset price is feasible to support development of an MEU. If the City decides that the feasibility is no longer valid, the process ends at that point. If the City decides to proceed with municipalization, the next step would be for the City to file a condemnation action with the court.

The result of the condemnation process is the final decision point by the City to determine if the determined asset price is feasible to support development of an MEU. If the City decides that the feasibility is no longer valid, the process ends at that point. However, if it decides that the purchase price supports moving forward, the City will begin discussion and negotiations with SDG&E to determine the process for transferring assets to the City and to begin MEU operations.

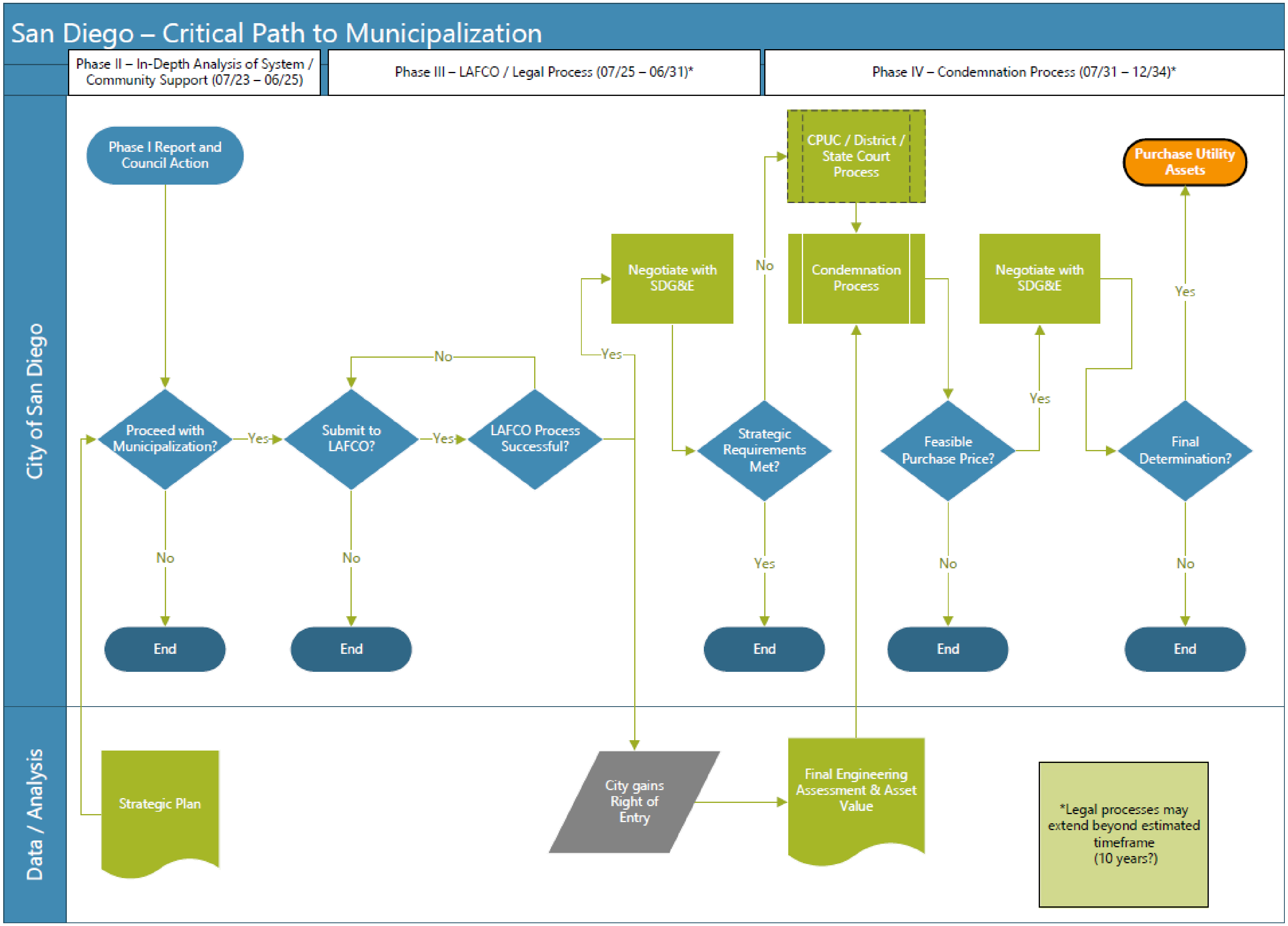


Figure 10-1. Critical Path to Municipalization (Process Map)

Public Power Process (Detail)

The following provides a detailed description of the Public Power Process Map (Figure 10-2) developed for the City assuming the City decides to proceed with Phase II activities. This Phase I report will be presented to the City, and it is anticipated that the City will support initiation of the Phase II activities. These anticipated activities include further refinement of the asset valuation, stakeholder engagement, and development of a Municipalization Strategic Plan and Phase II report. The Municipalization Strategic Plan would be expected to incorporate feedback from the stakeholder engagement process (as described further in its own process map below) as well as insight from other entities, including SDG&E, SDCP, and the IBEW Local 465, which is the current union that supports the majority of SDG&E field operations in the region. This stakeholder engagement and outreach process will be used to help develop the specifics of the Municipalization Strategic Plan. The specifics of the Municipalization Strategic Plan will need to be defined by the City as part of this process. The resulting decision required by the City Council upon delivery of the Phase II report will be whether to continue to move forward with municipalization. If so, the City would need to prepare its LAFCO docket while initiating discussions with SDG&E. These discussions should center on the ability of SDG&E to meet the requirements of the City's Municipalization Strategic Plan, which, if met, may result in the City's decision to end the municipalization process. However, if SDG&E cannot meet the City's strategic requirements, the City can decide to proceed with Phase III efforts.

Phase III efforts include initiation of the LAFCO and regulatory/legal processes (see the LAFCO subprocess defined below). The submission to the LAFCO has been defined in this process map as the initial activity associated with "Phase III" efforts, which are roughly anticipated to begin in July 2025. The LAFCO will determine if the City's application warrants the development of an MEU. As part of its decision, the LAFCO may decide that additional information and/or support is necessary, or that creation of an MEU is not warranted. If the LAFCO process is not successful, the City faces another decision point: resubmit its application or decide to end its pursuit of municipalization. If it decides to move forward with favorable support from the LAFCO, it is anticipated that SDG&E will be required to provide access to its books and records (Right of Entry), as indicated in the SDG&E lane. The LAFCO decision process is its own process, within the "Jurisdictional/Regulatory" lane, which is anticipated to include challenges from other entities at the LAFCO. A successful LAFCO process will also result in the City's decision to potentially enter into direct negotiations with SDG&E. These direct negotiations will allow the City to further evaluate the ability of SDG&E to support its strategic requirements and, if an agreement is reached, the City could decide to end its municipalization effort.

If the City decides to continue its efforts to municipalize, it is anticipated that it will move into Phase IV activities, which include condemnation of SDG&E assets. It is expected that upon completion of the LAFCO process, the City will file its plan of acquisition with the CPUC and/or District or State courts, as appropriate. There may be a concurrent filing with both CPUC and the courts to determine which entity has original jurisdiction; however, it is anticipated that there will be challenges by SDG&E and others at either entity. The condemnation process is anticipated to be supported by the development of a Final Engineering Assessment and Asset Value report to be provided to the judicial and/or regulatory body that will make the final determination of value. Concurrent with the condemnation process, the City will need to initiate its transitional and operational readiness process, which will continue the efforts identified in this Phase I report regarding the future structure, operations, and functionality of a municipally owned utility. As a result of the condemnation process, the City will need to decide if the asset prices support the feasibility of an MEU, and if not, the process could end at that decision. If the MEU is feasible at this point, the City could decide to continue its negotiations with SDG&E, which will result in another decision point by the City (and the results of a final court determination of value). The City could elect to end its municipalization at that point or begin its operational readiness process.

The operational readiness process includes the results from the previously initiated transitional and operational effort, which would identify, define, and create the various governance, operational, and implementational entities within the City which are necessary to support an MEU. The decision to move forward at the end of Phase IV will result in the purchase of SDG&E utility assets, as well as negotiations with IBEW Local 465 regarding their ability to support the newly created MEU. The transition between Phase IV (condemnation) and the operational readiness process is deliberately vague in terms of the time requirement. This is because there could be several operational and transitional elements that will need to be fully developed prior to the City taking control of the MEU. However, this process is anticipated to occur well into the future and will become more clearly defined as the City decides on the organizational structure for the MEU.

The operational readiness process identifies purchasing the SDG&E utility assets, but also realizes there is a significant communication and engagement plan requirement, as well as financing process, to support the eventual MEU operations. Additionally, the City will need authorization from its City Council to communicate with SDG&E to develop a successful Operational Agreement between the City's utility operations and the continued operation of SDG&E (beyond the municipal boundaries), as well as to develop the operational agreements with other entities and staffing requirements. Upon completion of the operational report and implementation of the report recommendations, the City will begin operating as an MEU.

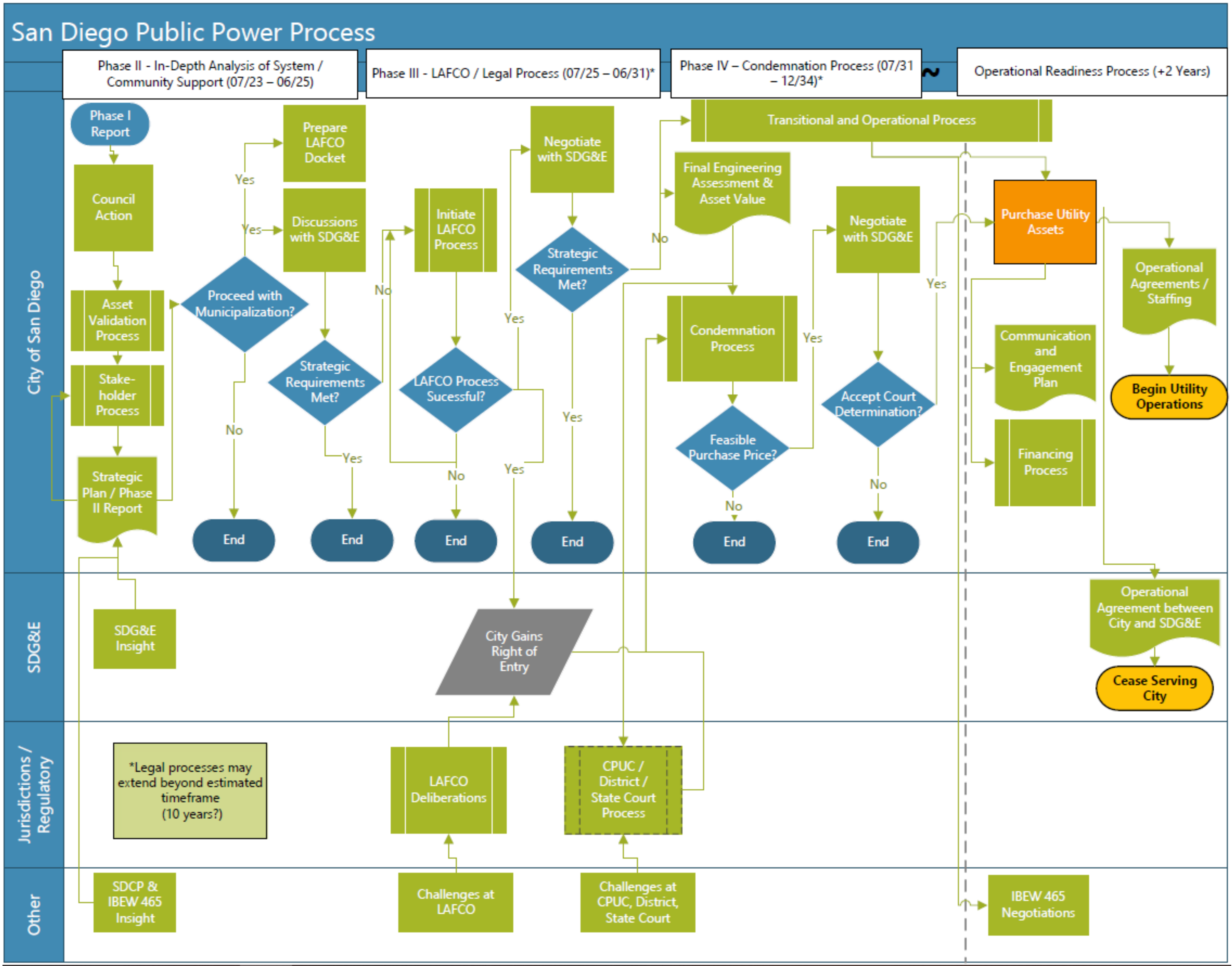


Figure 10-2. Public Power Process (Process Map)

Stakeholder Subprocess

The stakeholder subprocess would be expected to begin upon completion of this Phase I report and will be an integral part of the Municipalization Strategic Plan. Several entities have been identified whom the City would likely engage as stakeholders; each entity has been assigned its own lane for the purposes of the stakeholder subprocess map. These entities include SDG&E, SDCP, and IBEW Local 465, as well as other "external stakeholders" which include community organizations and the public. The engagement process and goals for each entity are slightly different. For SDG&E, the discussions will focus on the feasibility of the utility to meet the City's strategic objectives, as well as requests for additional data to evaluate the City's municipalization efforts. SDCP discussions are expected to focus on the potential structure of the MEU and the relationship between SDCP and the City wherein, as previously noted, SDCP is expected to provide all the power supply to the electric customers within the City, as well as legal analysis of potential changes to the contractual relationship between the MEU and SDCP. Additionally, discussions would need to occur regarding the operational integration with SDCP of the MEU serving the electric delivery and billing needs of the customers within its municipal boundaries.

As previously indicated, the IBEW Local 465 union that currently supports SDG&E electric delivery services has been identified as a key contributor to the stakeholder engagement process. Discussions with IBEW Local 465 will center on its wants and needs as they relate to the City's potential operation of the electric delivery systems within the City, and if the union would be able to support the City in the future. This discussion would also focus on the timing of the City's potential acquisition of the SDG&E assets and how those timelines fit with current and future contract negotiations between the union, SDG&E, and the City. Other external stakeholders, such as community-based organizations, issues advocacy organizations, other civic groups, and the general public, would also be incorporated into the stakeholder engagement process. The focus of these discussions is expected to be on public outreach and education about what an MEU could provide to its customers, as well as feedback on priorities to be incorporated into the Municipalization Strategic Plan, as appropriate.

The cumulation of the stakeholder engagement process will be for the City to finalize its Municipalization Strategic Plan with any outstanding issues or concerns addressed from the stakeholder groups, as necessary. When finalized, the Municipalization Strategic Plan would be expected to recommend the formation of a formal Advisory Panel, made up of some of the stakeholder entities. The mission of the Advisory Panel would be defined in the Municipalization Strategic Plan; however, the expectation is that this group would provide comments, feedback, and review to the City's policies regarding ongoing municipalization efforts. The conclusion of the stakeholder process would end with the development of the Municipalization Strategic Plan and Phase II report.

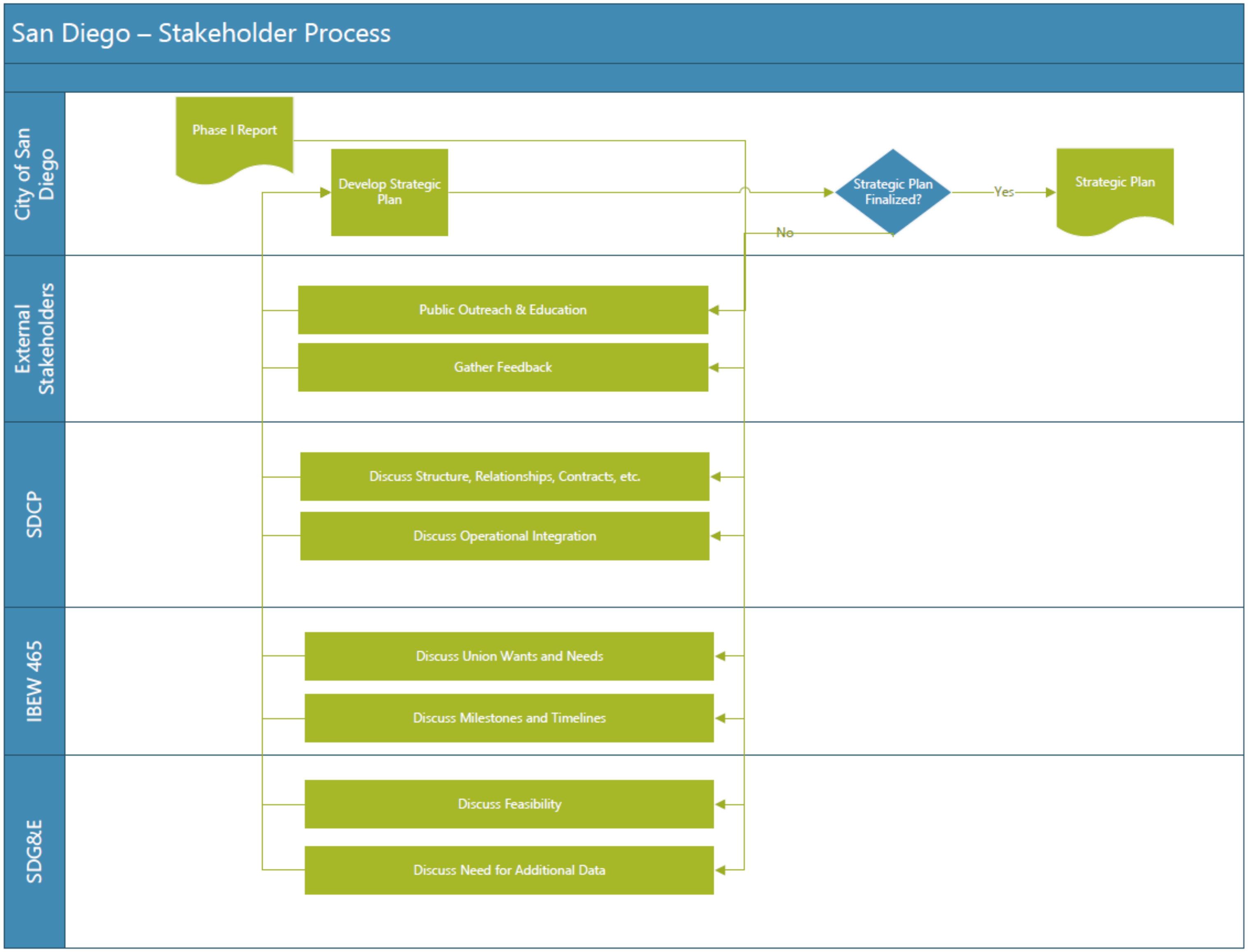


Figure 10-3. Stakeholder Process (Process Map)

LAFCO Subprocess

The initial decision in the LAFCO subprocess for the City is to determine if it will submit an application to the LAFCO to form an MEU. If the City decides to not submit to the LAFCO, it effectively ends the municipalization process. As indicated, the LAFCO will decide if the City's application presents sufficient information to demonstrate that forming an MEU is in the public's interest. If the LAFCO decides to allow the City to form a municipal utility, the City can decide at that point to move forward with its efforts. If the LAFCO denies the City's petition, it may be due to insufficient information or failure to support the City's position of need to form an MEU. At that point, the City can decide to resubmit its application to the LAFCO (depending on the specifics of the LAFCO decision), or it can decide to conclude its municipalization effort.

As previously noted, approval by the LAFCO is expected to allow the City to gain access to SDG&E's books and records (Right of Entry). However, it is anticipated that SDG&E will initiate litigation if the LAFCO issues approval to the City. This may result in subsequent legal filings at the superior court, appellate court, or the Supreme Court of California, depending on original jurisdiction and any appeals of lower court decisions by either the City, SDG&E, or other affected parties. If SDG&E does not choose to litigate the findings of the LAFCO, there may be an opportunity for the City to enter into negotiations directly with SDG&E.

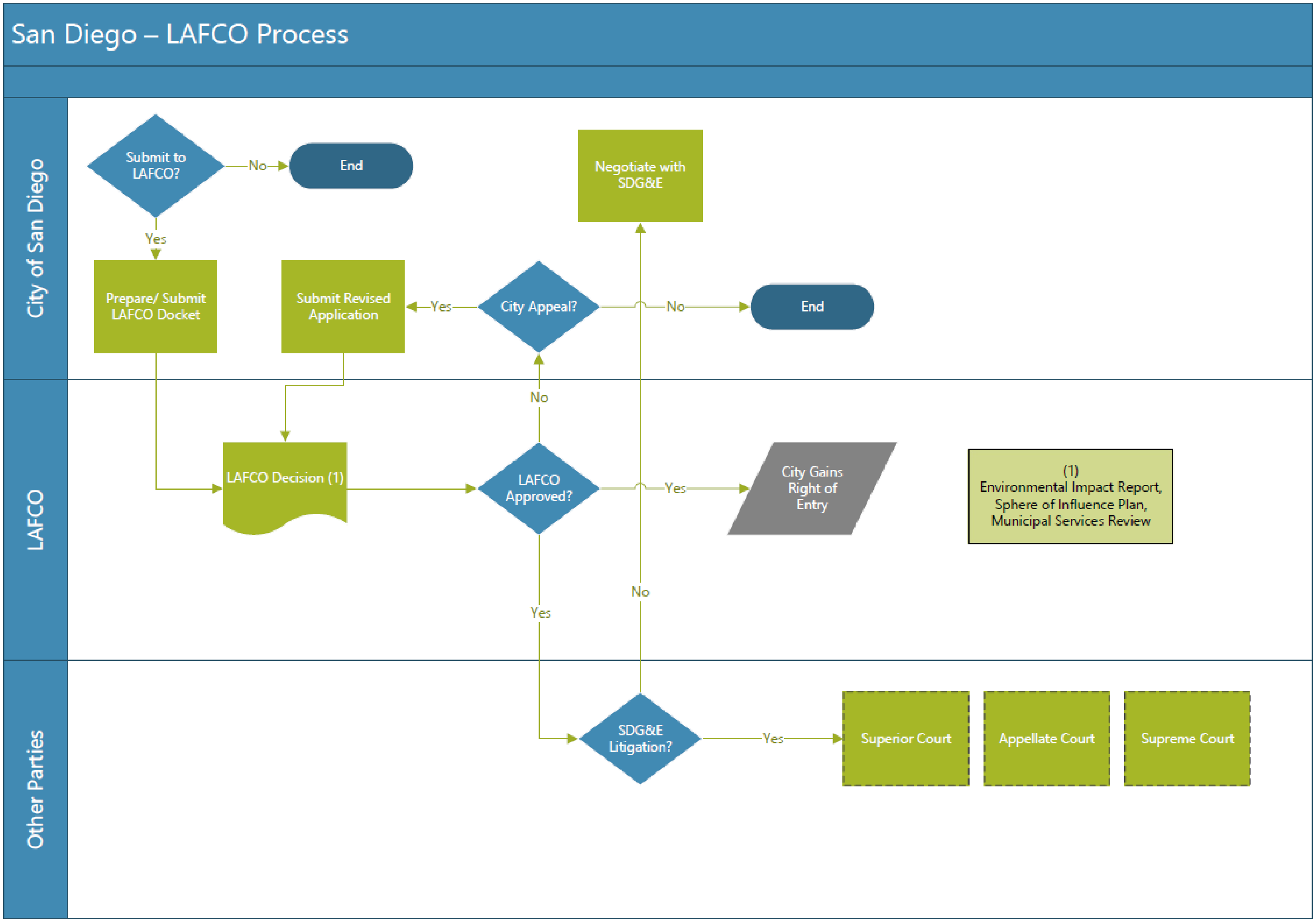


Figure 10-4. LAFCO Process (Process Map)

CPUC Subprocess

While not legally required for all municipalization efforts, the City may wish to petition the CPUC to determine the value of SDG&E assets the City wants to acquire. In anticipation of this, the CPUC Subprocess has been included as a component of the process maps (See Figure 10-5). The CPUC Subprocess is expected to begin after the City's initial negotiations with SDG&E (and after a successful LAFCO process), and a subsequent decision by the City to move forward with the municipalization effort (if its strategic requirements cannot be met by SDG&E). The City would need to develop a petition to the CPUC to determine the value of the SDG&E assets within its municipal boundaries and as defined in its pleadings. The CPUC would decide to either accept or deny the City's motion. If denied, the City could revise its petition and resubmit it to the CPUC to address any deficiencies in its original filing, or it could decide to end the municipalization process. If the CPUC accepts the City's motion, it would initiate a sequence of events, processes, and documents similar to a litigated case.

Specifically, the phases of discovery, written testimony, hearings, briefs, proposed decision, and written comments to the CPUC have been identified. All these legal elements would be expected to either result in a CPUC issued motion for reconsideration of various elements in the case or result in a CPUC order for just compensation (the value that the CPUC determines for the SDG&E assets to be acquired). SDG&E could decide to enter into settlement discussions with the City during any phase of the ligated case, which would result in the City's decision to either move forward with municipalization or end the process. Upon either a successful settlement discussion or valuation decision by the CPUC, the City would need to determine if the asset value supports municipalization (determine feasibility). If not, the City could submit a motion for reconsideration or move to end its municipalization effort. If the asset value supports a feasible municipalization effort, the City can decide to move forward with the condemnation process.

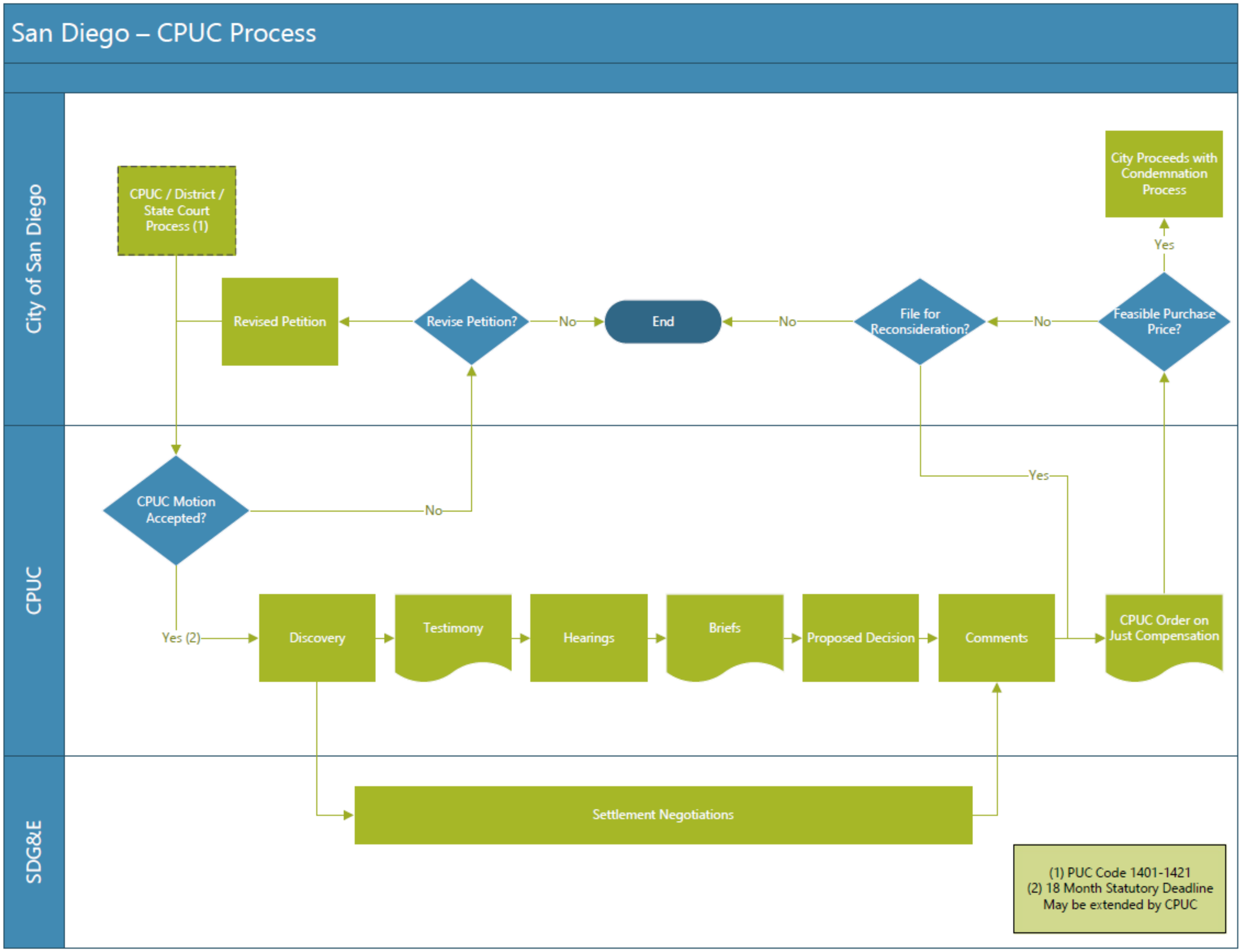


Figure 10-5. CPUC Process (Process Map)

Condemnation Subprocess

The condemnation subprocess is anticipated to begin upon CPUC's determination of a successful valuation of the assets to be acquired by the City (see Figure 10-6). A successful value indicates that the City has determined that the CPUC value supports municipalization and that negotiations with SDG&E have failed to achieve its strategic requirements. The first step in the condemnation process is for the City to make an offer to SDG&E for its assets. If SDG&E accepts the offer, the City can move forward with the purchase. However, it is anticipated that SDG&E would not accept the offer, and the City would be expected to either negotiate with SDG&E on the value or file its case in condemnation court (assumed to be in a district court). Negotiations could lead to an agreement to either purchase the assets or end the municipalization effort. The legal condemnation process would be expected to occur in a litigated case, similar to that of the CPUC valuation, and include a jury or judge only trial. The outcome of the trial would be a final court determination either allowing or disallowing the condemnation of the SDG&E assets by the City. If the court disallows the condemnation, the City's municipalization effort ends. However, if the court allows condemnation, then the City can decide to purchase the utility assets.

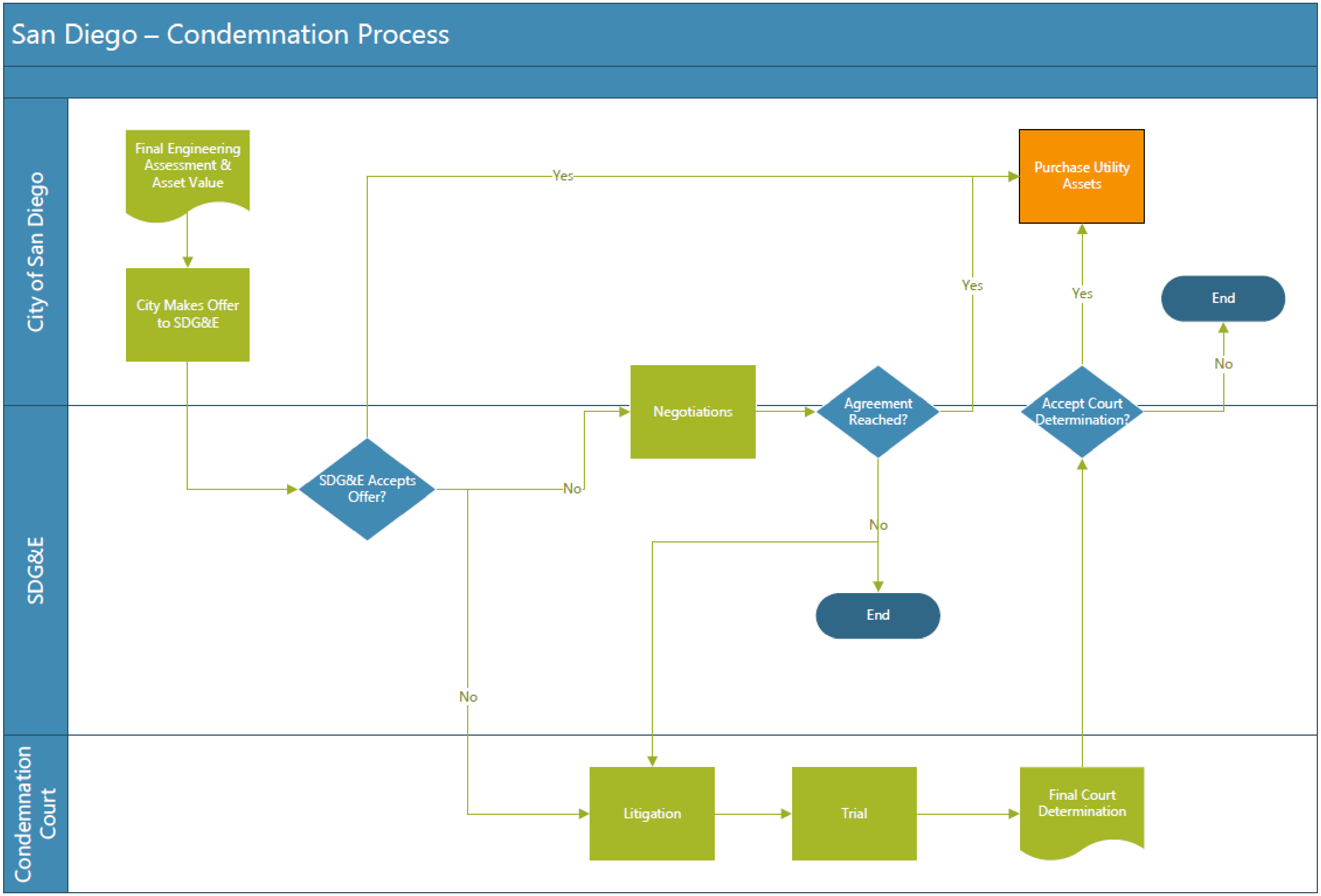


Figure 10-6. Condemnation Process (Process Map)

Section 11
CONCLUSION

The City is actively investigating its options to expand its municipal utility service offerings as it continues to strive to meet the needs of its citizens and businesses to provide opportunities and fulfill its potential. In continuance of this investigation, the City initiated efforts to obtain independent third-party services to provide technical, economic, and policy insight to create a public power entity. This resulting Study was established with a multi-phased approach to evaluate the processes, costs, risks, and opportunities associated with municipalizing the energy infrastructure assets of SDG&E within the City.

As noted in Section 1, this project was initially tasked with examining the prospect of acquiring both the electric and natural gas delivery assets within the City. However, as part of the City's CAP, the City set a target to phase out 100% of natural gas usage in municipal facilities and 90% of natural gas load from existing buildings by 2035. Therefore, the development of a municipal natural gas utility would not be consistent with the City's CAP goals and would be financially unwise in the long term, and further analysis of the acquisition of the SDG&E natural gas system was determined to be infeasible as part of the Phase I Study.

This report represents Phase I of the Study. The specific elements requested by the City to be included in this Phase I Study are as follows:

- Develop Process Maps.
- Public Power Entity Options.
- Initial financial determinations regarding existing electric systems in the City.
- Initial financial and operational options and needs for a Public Power entity.

This section provides a conclusion and findings of the specific elements included in this Study.

Process Maps

The process maps are introduced in Section 1 of this report and are more fully explained and provided in detail in Section 10. The process maps provide the City with an overview of the various analysis, decision points, and feedback loops inherent in the City's municipalization decision. The process maps are designed to focus on the City's requirements as it contemplates municipalization. A timeframe along the top of each process graphic has been developed based on the professional experience of the NewGen Team and input from the City.

The conclusion of the process maps is that there are established processes (both legal and regulatory) for the City to continue its investigation into forming an MEU within the City. Further, there are specific policy considerations that the City should address during this process. The most critical considerations would be addressed within the proposed next phase of the Study (Phase II), additional detail for which is recommended below.

The process maps, based on the NewGen Team's experience, suggest that the time required to fully accomplish the objective of forming an MEU will at a minimum be eight to ten years. However, that timeframe could easily be expanded by the actions and decisions of external parties, including SDG&E. As referenced throughout this report, there are significant challenges to acquiring existing assets to form an

MEU, particularly if there is an unwilling seller. The City should be fully aware of the range of risks (political, financial, operational, and others) that exist during a municipalization process.

Public Power Entity Options

In review of forming an MEU, the City recognizes that there are a multitude of successful municipal electric utility structures and governance options that exist. For this Study, the NewGen Team conducted a preliminary evaluation of the various options for the structure, governance, and organization of a potential public power entity. This was accomplished by conducting an in-depth organizational assessment of the current City operations which focused on the opportunities and challenges that currently exist within the City relative to the potential establishment of an MEU.

Of the structures identified and included in this Study, the ones that are the most promising to meet the requirements of the City and the needs of an MEU seem to be either a Public Charitable Trust or a Special District. For the City to establish an MEU, there would be challenges to the existing City resources, policies, and structures without significant upgrades to systems and staffing and an overhaul of certain policies and procedures. A detailed implementation plan is required to ensure a smooth transition. It is the NewGen Team's opinion that it may be preferable to create certain services independently rather than attempting to shoehorn them into existing City services and departments. The impacts on support systems required by electric service and delivery are more complicated and challenging than similar systems maintained by the City. Many departments that provide shared services are currently at capacity and are not likely to be able to support an MEU without significant additional resources. There are also labor and management considerations that would need to be taken into account, including significant union agreements and staff and stakeholder communications. Accordingly, the City would need to begin coordinating with the IBEW utility workers chapter and other stakeholders early in the acquisition process to make the hiring process as smooth as possible (as included in the recommendations for Phase II efforts below).

Initial Financial/Operational Determinations

The High-Level Financial Capacity Results illustrate that the acquisition of the SDG&E electric delivery assets in the City is financially feasible based on the assumptions presented herein. It is critical to examine the estimated results on both a cumulative and relative basis. The cumulative savings capture the impact of upfront costs to determine how long it may take to recover these costs, especially as debt service for the initial acquisition financing comes online. The relative costs are also important given the size of the overall enterprise. While the illustrative high-level savings may be large, they must also be evaluated in the context of the projected SDG&E UDC revenue requirement to have some sense of the relative savings.

The relative savings are also important because they are being shown strictly on a financial basis and have not been adjusted for any "risk weighting." As discussed herein, there are significant policy, business, organizational, legal, regulatory, and operational considerations, among other factors, that will be weighed in the context of overall feasibility. Both quantitative and qualitative considerations will need to be evaluated in the MEU business model.

A summary of the preliminary economics demonstrating the cumulative benefit of the OCLD and the RCNLD valuation estimates for the 10-, 20-, and 30-year timeframes is shown below in Table 11-1.

Table 11-1
Summary of Preliminary Economics ($M)(1)

	Year 10	Year 20	Year 30
Est. Cumulative SDG&E UDC Revenue Requirement ($)	$22,000	$55,000	$100,000
OCLD Cumulative Benefit ($)	$3,000	$8,000	$15,000
OCLD Cumulative Benefit (%)	13% to 14%	14% to 15%	14% to 15%
RCNLD Cumulative Benefit ($)	($60)	$2,000	$6,000
RCNLD Cumulative Benefit (%)	0%	3% to 4%	5% to 6%

(1) For illustration purposes only; Actual Results will vary.

Next Steps/Phase II

This Phase I report concludes that it is financially feasible for the City to acquire specific SDG&E electric assets in the City. However, as indicated, there are several difficulties and challenges that will require the City to examine the various political, operational, and financial risks associated with forming an MEU. Recommended next steps for activities include the following:

- Development of a Preliminary Electric Municipalization Strategic Plan. This document will address the policy objectives of the proposed MEU as they relate to the City's CAP and other environmental policies and strategic documents. The Municipalization Strategic Plan should incorporate the findings from this Phase I report as appropriate.
- Prepare/Facilitate Stakeholder Engagement. A critical element to a successful municipalization effort is the support of the community. As part of this Phase I Study, a Stakeholder Process has been identified for this purpose. Phase II would include initiating the stakeholder process with the various groups identified in the Stakeholder Process. Stakeholder groups would be identified and engaged in parallel with a preliminary Municipalization Strategic Plan which will then be iterated through continued feedback and communication with the stakeholder groups.
- Stakeholder Process Feedback. The City will need to incorporate feedback from the Stakeholder Process and ensure transparency in its management of this effort. Various groups identified may have differing opinions on the need for and ability of the City to effectively form an MEU, and these opinions should be addressed in subsequent revisions of the City's Municipalization Strategic Plan.
- LAFCO Application Preparation. The LAFCO application is a formal document in which the City expresses that according to the studies carried out, it is in the best interests of the citizens of San Diego to proceed with the municipalization. This assessment will be contested by SDG&E, and in Phase II it is important that robust cost estimations are made so that some high-level assumptions made in Phase I can be removed. This requires:
    - Updating the inventory by field inspections and, based on this, confirming or modifying the top-down ratios used in the analysis to estimate the conductor sizes and length, number of transformers by size, number of poles by size, capacitor banks number and size, etc. This is to be carried out by feeder and will result in a better estimation of the distribution system's RCN and hence the purchase price.

- Reviewing SDG&E FERC Form filings on Capital Work in Progress and historical construction permits, as available, to improve the estimation of assets' ages.
- Updating the distribution severance plan with field inspections of the feeders crossing the border as well as available maps. This will result in a better severance plan and may include a staged implementation starting from extensive use of MV/LV metering to a near full separation of customers by full implementation.

- Assessment of Transmission System Expansion. The City should assess the benefits and costs of expanding the transmission system acquisition to include 230 kV within the City and 138 kV and 69 kV yards of the Border Substations and lines to SDG&E outside the City and metering there instead of at the City's substations. This will necessitate the following:
  - Improving estimation of the transmission severance plan by reviewing the layouts of the border substations and identifying actual investments to be made by substation to separate from SDG&E. This includes at least a review of the 69/138 kV yards, the MV yards, and the feeders supplied by each substation.
  - Assessing distribution capital expenditures. The expected impacts in the network of the forecasted load growth (including EV charging) and DG should be reviewed and performance violations addressed, producing a Distribution Master Plan. This plan will identify major investments by substation.
  - Assessing transmission. Based on the Distribution Master Plan and loads by substation, expansion needs on the City's future 138/69 kV transmission system, lines and substations, and the MV substation yards should be identified. This will be complemented by a review of the CAISO transmission plans for the region.
  - Estimating start-up costs and ongoing capital costs for asset replacement.
  - Selecting the final recommended organization structure and updating associated O&M, Customer, and A&G costs.
- Update of Final Municipalization Strategic Plan with Stakeholder Inputs. The final Municipalization Strategic Plan and Phase II report will need to include insight and comments from SDG&E, as appropriate, as well as other entities, such as SDCP and IBEW Local 465 (which are anticipated to be obtained through the Stakeholder Engagement process).
- Creation of Phase II Report. At the conclusion of the Phase II efforts, which is anticipated to be Summer 2025 should the City decide to proceed, the City will be faced with another decision point if it wishes to move forward with forming an MEU. The purpose of the Phase II report would be to provide further insights and information on the financial feasibility of a City-owned MEU and to prepare for the next phase in the process, development of the LAFCO submission packet, which is defined in the LAFCO process map in Figure 10-4.

APPENDIX A: NERC STANDARDS TABLES

PUBLIC POWER FEASIBILITY STUDY

PHASE I REPORT

Appendix A
NERC Standards Tables

Table A-1
MEU NERC Requirements

Standard Number	Standard Title	Purpose
CIP-002-5.1a	Cyber Security — BES Cyber System Categorization	To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements.
CIP-003-8	Cyber Security — Security Management Controls	To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric system.
CIP-004-6	Cyber Security — Personnel & Training	To minimize the risk against compromise that could lead to misoperation or instability in the Bulk Electric System (BES) from individuals accessing BES Cyber Systems by requiring an appropriate level of personnel risk assessment.
CIP-005-7	Cyber Security — Electronic Security Perimeter(s)	To manage electronic access to BES Cyber Systems by specifying a controlled Electronic Security Perimeter in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability.
CIP-006-6	Cyber Security — Physical Security of BES Cyber Systems	To manage physical access to Bulk Electric System (BES) Cyber Systems by specifying a physical security plan in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability.
CIP-007-6	Cyber Security — System Security Management	To manage system security by specifying select technical, operational, and procedural requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability.
CIP-008-6	Cyber Security — Incident Reporting and Response Planning	To mitigate the risk to the reliable operation of the BES as the result of a Cyber Security Incident by specifying incident response requirements.
CIP-009-6	Cyber Security — Recovery Plans for BES Cyber Systems	To recover reliability functions performed by BES Cyber Systems by specifying recovery plan requirements in support of the continued stability, operability, and reliability of the BES.
CIP-010-4	Cyber Security — Configuration Change Management and Vulnerability Assessments	To prevent and detect unauthorized changes to BES Cyber Systems by specifying configuration change management and vulnerability assessment requirements in support of protecting BES Cyber Systems from compromise that could lead to misoperation or instability.
CIP-011-2	Cyber Security — Information Protection	To prevent unauthorized access to BES Cyber System Information by specifying information protection requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability.
CIP-012-1	Cyber Security – Communications between Control Centers	To protect the confidentiality and integrity of Real-time Assessment and Real-time monitoring data transmitted between Control Centers.

Table A-1
MEU NERC Requirements

Standard Number	Standard Title	Purpose
CIP-013-2	Cyber Security – Supply Chain Risk Management	To mitigate cyber security risks to the reliable operation of the Bulk Electric System (BES) by implementing security controls for supply chain risk management of BES Cyber Systems.

Table A-2
CAISO NERC Requirements

Standard Number	Standard Title	Purpose
EOP-004-4	Event Reporting	To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
EOP-005-3	System Restoration from Blackstart Resources	Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
EOP-006-3	System Restoration Coordination	Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection
EOP-008-2	Loss of Control Center Functionality	Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.
EOP-010-1	Geomagnetic Disturbance Operations	To mitigate the effects of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures.
EOP-011-2	Emergency Preparedness and Operations	To address the effects of operating emergencies by ensuring each Transmission Operator, Balancing Authority, and Generator Owner has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated.
TOP-001-5	Transmission Operations	To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
TOP-002-4	Operations Planning	To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
TOP-003-5	Operational Reliability Data	To ensure that the Transmission Operator and Balancing Authority have data needed to fulfill their operational and planning responsibilities.
TOP-010-1(i)	Real-time Reliability Monitoring and Analysis Capabilities	Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.
VAR-001-5	Voltage and Reactive Control	To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

Table A-3
MEU NERC Standards

Standard Number	Standard Title	Purpose
FAC-001-3	Facility Interconnection Requirements	To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available.
FAC-002-3	Facility Interconnection Studies	To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.
FAC-003-4	Transmission Vegetation Management	To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW.
FAC-008-5	Facility Ratings	To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles.
FAC-010-3	System Operating Limits Methodology for the Planning Horizon	To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
FAC-011-3	System Operating Limits Methodology for the Operations Horizon	To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
FAC-014-2	Establish and Communicate System Operating Limits	To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies
FAC-501-WECC-2	Transmission Maintenance	To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP)
PRC-005-1.1b	Transmission and Generation Protection System Maintenance and Testing	To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested properly

Table A-4
Transmission NERC Standards

Standard Number	Standard Title	Purpose
TPL-001-4	Transmission System Planning Performance Requirements	Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions.
TPL-007-4	Transmission System Planned Performance for Geomagnetic Disturbance Events	Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.
MOD-001-1a	Available Transmission System Capability	To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors.
MOD-004-1	Capacity Benefit Margin	To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.
MOD-008-1	Transmission Reliability Margin Calculation Methodology	To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.
MOD-032-1	Data for Power System Modeling and Analysis	To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.
MOD-033-2	Steady-State and Dynamic System Model Validation	To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.
PRC-002-2 & -3	Disturbance Monitoring and Reporting Requirements	To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
PRC-004-6	Protection System Misoperation Identification and Correction	Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.
FAC-011-3	System Operating Limits Methodology for the Operations Horizon	To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
CIP 14-3	Physical Security	To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrollable cascading, and loss of load.
FAC-014-2	Establish and Communicate System Operating Limits	To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies

NewGen Strategies & Solutions

BB&A

Bell Burnett & Associates

SIEMENS

APPENDIX B: PROCESS MAP LEGEND

PUBLIC POWER FEASIBILITY STUDY

PHASE I REPORT

Appendix B
PROCESS MAP LEGEND

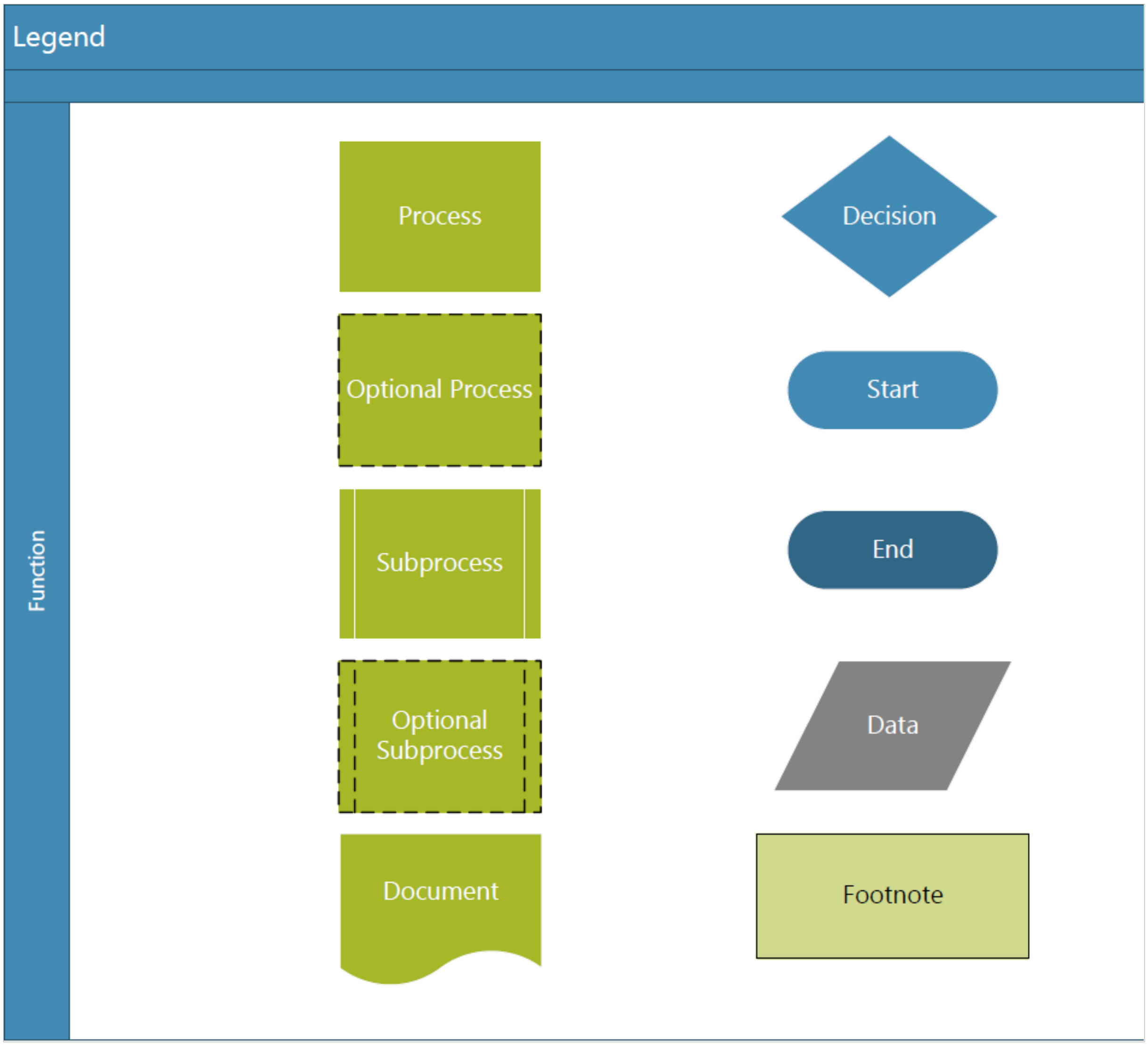


Figure B-1. Legend for Process Maps

NewGen Strategies & Solutions

BB&A
Bell Burnett & Associates

SIEMENS

225 Union Boulevard, Suite 450, Lakewood, Colorado 80228
Phone: (720) 633-9514
Email: info@newgenstrategies.net
www.newgenstrategies.net