SANTA CLARA CITY POWER

Capital Facility Plan, Impact Fee Facility Plan and Impact Fee Study

May 2022

R. E. Pender, Inc.
P. O. Box 5847
Frisco, TX 75036
(321) 279-7261

Intermountain Consumer
Professional Engineers, Inc.
1145 East South Union Avenue
Midvale, Utah 84047
(801) 255-1111

Table of Contents

SECTION 1 - Background 1
1.1 Introduction 1
1.2 Impact Fees - General 1
1.3 Impact Fees - Utah 3
1.4 Santa Clara City and SCCP 4
1.5 Washington County 5
1.6 Electricity Supply & Demand 5
1.6.1 General 5
1.6.2 Electricity Supply 6
1.6.3 Transmission of Electricity 7
1.6.4 Distribution of Electricity 8
SECTION 2 - Capital Facilities Plan and Impact Fee Facilities Plan 10
2.1 General 10
2.2 Historical Population and Load Growth 10
2.3 Existing Electric Infrastructure and Future Needs 11
2.3.1 Generation 11
2.3.2 Transmission 12
2.3.3 Substations 13
2.3.4 Distribution 15
2.4 Level of Service Standards 15
2.5 Demands Placed on Existing Facilities 16
2.6 System Modeling for the CFP/IFFP 18
2.7 Model Results 19
2.8 IFFP Capital Projects and Costs 21
2.9 Certification of the IFFP 23
SECTION 3 - Impact Fee Analysis 24
3.1 General 24
3.2 Impact Fee Analysis 24
3.2.1 Identification of Impact Fee Projects/Costs 24
3.2.2 Impact Fee Demand Analysis 25
3.2.3 Calculation of the Impact Fee 26
3.3 Impact Fee Charges – Present and Proposed 27
3.4 Certification of the IFA 29

EXHIBITS

Exhibit 1 – Forecasted Customers, Energy and Demands, 2022 - 2041

Exhibit 2 – Impact Fee Projects / Costs

Exhibit 3 – Impact Fee Demand Analysis

Exhibit 4 – Impact Fee Cost Analysis

Exhibit 5 – Summary of Charges – Current & Proposed Impact Fees

APPENDICES

Appendix A – Utah Statute U.C.A. 1953 § 11-36a-102

Section 1 - Background

1.1 Introduction

Santa Clara City Power ("the City," "Santa Clara" or "SCCP") engaged the services of Intermountain Consumer Professional Engineers, Inc. ("ICPE") who teamed with R. E. Pender Inc. ("Consultant") to conduct certain studies and analyses related to the development of an updated Electrical Power Capital Facilities Plan, Impact Fee Facilities Plan Update, and Impact Fee Analysis (collectively, "the 2022 Impact Fee Study"), the results of which will be implemented upon city council approval.

The 2022 Impact Fee Study was issued to update the previous study which was performed in 2016 by ICPE. This study was similar in scope to the current study and a similar methodology was used to create the updated study.

In conducting the subject study, certain publicly available information, data supplied by SCCP and electronic spreadsheets developed specifically for this engagement were utilized. In reaching the conclusions and recommendations discussed herein certain assumptions and considerations were made regarding future events and circumstances that may affect the ultimate outcome of the results. No assurances or guarantees are made as to the actual outcome of any assumption or consideration made in the development of these studies. However, it is believed that all assumptions and considerations made herein are appropriate and reasonable for purposes of the Impact Fee Study. In addition, certain information was obtained by the Consultant from other sources, all of which are believed to be reliable and reasonable for the purpose of this undertaking.

1.2 Impact Fees - General

Generally speaking, impact fees are used by government agencies (e.g., city and county governments) to fund certain capital-related expenditures (e.g., new infrastructure) incurred in providing governmental services to "new" development as mandated by law or ordinance. The basic philosophy behind the implementation of impact fees is that "new" development should bear the additional or "incremental" capital cost incurred in order to provide services to the "new" development. This establishes a cost causation or "nexus" requirement between the cost incurred in providing the service and those who benefit from the service. To be clear however, impact fees are not intended to recover annual operating expenses (e.g., utility costs) or to pay for capital expenditures related to the correction of an existing deficiency in the service provided.

There are two generally recognized methods for calculating impact fees: the *inductive* method and the *deductive* method.

Under the *inductive* method, the cost and capacity of a particular facility is identified and used as the generic model for all future facilities. Take for example the cost of a new electrical substation having a construction cost of $2,000,000 and sized to serve approximately 5,000 residential dwelling units and 1,000,000 square feet of commercial space. In this very simple example, assuming the capital cost is recovered evenly (50% each) between residential and commercial loads, the impact fee would be determined as follows:

Residential	=	$2,000,000 x .50 / 5,000 = $200 per dwelling unit
Commercial	=	$2,000,000 x .50 / 1,000,000 = $1.00 per sq. foot.

An advantage to this method is that it is fairly straightforward and easy to implement. It also is not affected by changes to capital improvement plans or population estimates. The monies needed for the future capital requirement (like the electrical substation in the above example) will be available as soon as actual growth reaches the design levels, which may be any number of years down the road. A disadvantage of the inductive method is that the impact fee calculation is based on a generic model approach and, therefore, may not address the special needs of the community. It also may fail to capture all of the capital requirements associated with the project, including, for example the additional facilities that will be needed to support the primary project (e.g., required increases to the capacity of administrative support offices).

The *deductive* approach involves calculating the impact fee based on the anticipated additional demand (e.g., number of new residential dwelling units) on a facility or infrastructure used in providing services. Normally, the entity implementing the impact fee usually will have an established level of service ("LOS") standard for the particular service (e.g., 1 community park per 5,000 population) or alternatively, the current LOS (1 community park serving an existing population of 4,000) is used as the basis to determine the capital requirements underlying the impact fee calculation. In either case, once the LOS standard is known, it is a matter of applying that standard to future growth projections in population and/or commercial space as reflected in a master plan and/or capital improvement plan to determine the new capital requirements.

An advantage of using the deductive method is that it will address the specific needs of the community when determining the future capital requirements. The downside is that this method requires much more detailed information to perform the calculations and must be updated periodically as changes in population projections, master plans, etc. occur.

The inductive and deductive methods are both valid and the use of one or the other will depend largely upon the information available and the specific circumstances of the community. In calculating the subject electrical impact fees for Santa Clara we have employed only the deductive approach.

1.3 Impact Fees - Utah

Almost all states have some form of impact fees and 26 of those states have statutes authorizing the use of impact fees. In Utah, impact fees are governed by state statute, specifically U.C.A. 1953 § 11-36a-102 (the “Statute”). A copy of the Statute is attached hereto as Appendix A.

Very generally, the Statute requires that each political subdivision imposing an impact fee shall, with some exceptions, (1) prepare an Impact Fee Facilities Plan (§ 11-36a-301), (2) perform an Impact Fee Analysis (§ 11-36a-303), (3) calculate the Impact Fee(s) (§ 11-36a-305) and (4) certify the Impact Fee Facilities Plan (§ 11-36a-306).

According to the Statute, the “Impact Fee Facilities Plan (“IFFP”) shall identify (a) demands placed upon existing public facilities by new development activity; and (b) the proposed means by which the political subdivision will meet those demands.” The IFFP shall also generally consider all revenue sources, including impact fees, used to finance impacts on system improvements. This report incorporates the system SCCP Capital Facilities Plan (CFP) by reference but noting that the primary difference between the IFFP and the CFP is that the IFFP considers only those projects that are brought about by future growth on the SCCP system. That is, certain projects identified in the CFP may be due to the correction of an existing deficiency and therefore are not considered in the IFFP.

The Impact Fee Analysis (“IFA”) portion of the Statute states that (1) “each local political subdivision or private entity intending to impose an impact fee shall prepare a written analysis of each impact fee:” and (2) “shall also prepare a summary of the impact fee analysis designed to be understood by a lay person.” The requirements of the IFA include identifying the estimated impacts on existing capacity and system improvements caused by the anticipated development activity. The political subdivision must also estimate the proportionate share of (i) the costs of existing capacity that will be recouped and (ii) the costs of the impacts on system improvements that are reasonably related to the new development activity.

The calculation of the Impact Fee may include the following:

(a) The construction contract price;

(b) The cost of acquiring land, improvements, materials, and fixtures;

(c) The cost for planning, surveying, and engineering fees for services provided for and directly related to the construction of the system improvements; and

(d) For a political subdivision, debt service charges, if the political subdivision might use impact fees as a revenue stream to pay the principal and interest on bonds, notes or other obligations issued to finance the costs of the system improvements.

Also, the Calculation of the Impact Fee must be based on realistic estimates and the assumptions underlying such estimates must be disclosed in the IFA.

Finally, a written certification shall be included in the IFFP and the IFA by the person or entity that prepared those requirements.

1.4 Santa Clara City and SCCP

Santa Clara City is located in southwest Utah in Washington County, approximately 120 miles northeast of Las Vegas, NV. The estimated population in 2021 was about 9,521 persons, nearly a 60 percent increase since 2010. The median resident age is 36 years and the median household income is about $107,245. The land area is 6.1 square miles and the population density is 1,565 people per square mile. The average household size is 3.4 persons.[1] Santa Clara can best be described as a suburban community since many of its residents commute to work in the City of St. George and other nearby business areas. Santa Clara, as well as the surrounding area has a rapidly

[1] Source: worldpopulationreview.com/states/cities/utah

growing population. The St. George metro area, of which Santa Clara is a part, was recently ranked as the fastest growing community in the United States in a recent U.S. Census report.

SCCP provides electric power, transmission and distribution services to its customers located within the corporate limits of the City. For the year 2021, SCCP provided services to 3,125 electric accounts. SCCP owns and operates the Fort Clara Power Station. Electric systems located contiguously to SCCP include St. George City Power and Rocky Mountain Power (RMP).

1.5 Washington County

According to the 2020 U.S. Census, the County's population was 180,279, making it the fifth most populous county in Utah. Its county seat, as well as the largest city, is St. George having a population of just over 95,000. The county has a total area of 2,430 square miles, of which 2,426 square miles is land and 4 square miles is water. The population density is about 39 people per square mile. In 2019 there were about 57,100 households in the County and the median household income was $59,839. Local government, public education and retail trade make up the largest sector of employment with the largest area employers being Washington County School District, Intermountain Health Care, Dixie Regional Medical Center and Walmart.[2]

1.6 Electricity Supply & Demand

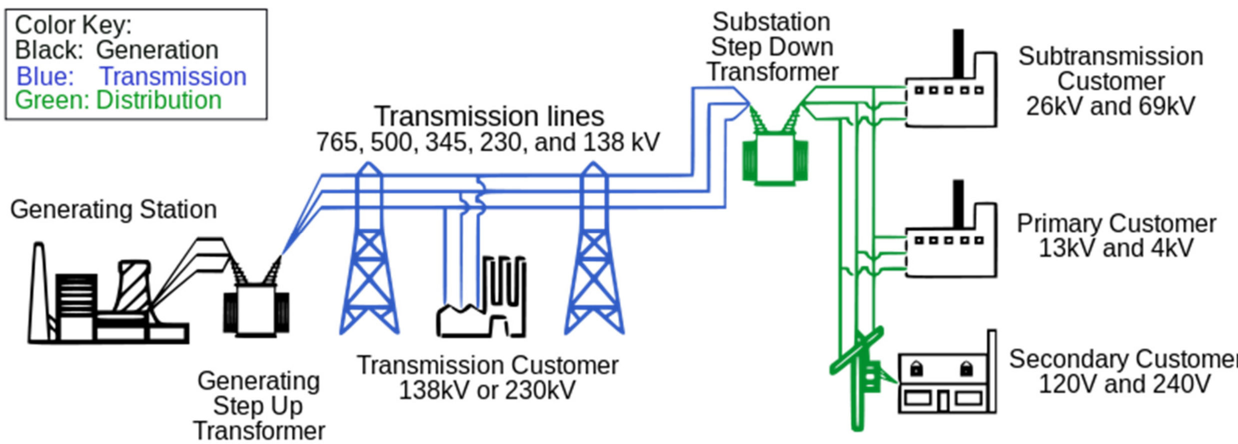
1.6.1 General

As illustrated in Figure 1-1 below, an electrical power delivery system is made up of three basic components or functions: electric generators that produce the power; a transmission system to deliver the power to the distribution system; and the distribution system which delivers the power to the end-user.

[2] Sources: Wikipedia.com and the St. George Area Economic Development website *www.growsga.com*

Figure 1-1

Illustration of a Typical Power Delivery System



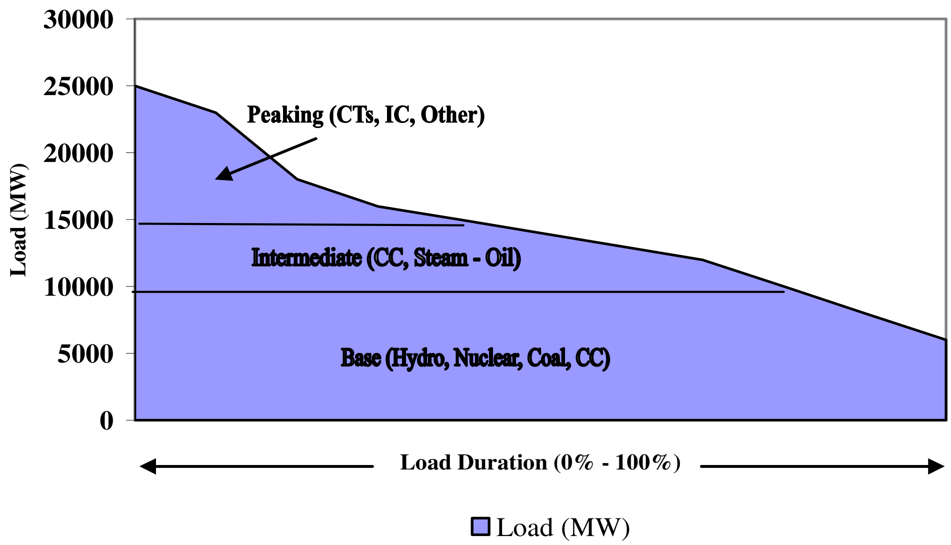
Source: en.Wikepedia.org

1.6.2 Electricity Supply

In any electrical system, electricity (measured in kilowatt-hours) is produced by a number of generation technologies, powered by a diversity of fuel resources. These generators may include steam (nuclear, coal and oil); hydroelectric (run-of-river and pumped storage); combined-cycle (natural gas and fuel oil); simple-cycle (natural gas and fuel oil); renewables (wing and solar) and internal combustion (diesel). The utility may also utilize generation supplied by others in the form of purchased power agreements, which can include firm power (long-term, interim and short-term); unit power (a purchase out of a specific generating unit) and non-firm (usually short-term). The type and amount of each generating resource that is utilized by the utility in meeting its hourly demand (measured in megawatts) for electricity at any point in time will depend primarily on the amount and duration of the demand, the availability of the generating units and the variable operating cost of the generating unit(s). Very simply, in meeting the daily demand for electricity, each available generating resource is stacked according to its operating cost (lowest to highest) and subsequently dispatched to meet the demand for electricity in each hour of the day. This so-called "merit" stacking/dispatch procedure can be illustrated as follows:

Figure 1-2

Illustration of a Load Duration Curve with Unit Stacking



The utility's peak demand is the highest demand for electricity (measured in megawatts) recorded in any one hour (based on a 15, 30 or 60 minute interval) and occurring within a specified time period (day, week, month, year or seasonal (summer, winter). It is during these peak periods that a utility will utilize its entire portfolio of generating resources including its peaking generating resources such as combustion turbines. However, because of their relatively high operating costs, combustion turbines are usually called upon for only a very short period of time – when the utility's peak demands are at the highest levels.

1.6.3 Transmission of Electricity

Immediately after leaving the generator, electricity is transformed (i.e., stepped up to a higher voltage) for delivery to the utility's high-voltage ("H-V") transmission system. Generally, the H-V transmission system consists of the towers, conductor, substations and other equipment necessary to deliver power from the various generating stations to the utility's distribution system or to other utilities interconnected with the H-V transmission system. H-V transmission system voltages typically range from 115 kilovolts to 500 kilovolts. A power transmission system is sometimes referred to colloquially as a "grid." Redundant paths and lines are provided so that power can be routed from any power plant to any load center, through a variety of routes, based on the economics and physical characteristics of the transmission path and the cost of power. Much analysis is done by transmission system owners to determine the maximum reliable capacity of each line, which, due to system stability considerations, may be less than the physical or thermal limit of the line. The H-V transmission system is continually monitored for potential "over-loading" conditions and utilities will sometimes be called upon to reduce/increase output at certain generating plants in order to relieve the condition. The location of generating plants in relation to the electricity load on the H-V transmission system is a very important consideration in utility planning. Needless-to-say, because of aesthetic, environmental, political, regulatory and other factors, generating plants and the transmission lines making up the "grid" can rarely be placed in the optimum location allowing for the for most efficient utilization of electric system. Transmission bottlenecks or "constraints" as they are typically referred to are sometimes created because the transmission grid is not configured or sized correctly to allow for the uninterrupted flow of power from the generating plant to the load centers experiencing the highest demand. Moreover, the level and duration of the constraint can vary depending on amount of load on the system, unit outages, and events affecting the flow of power.

1.6.4 Distribution of Electricity

Electricity distribution is the final stage in the delivery of electricity to end-users. A distribution system's network carries electricity from the transmission system and delivers it to consumers. Generally, a typical electric distribution system would include medium-voltage (e.g., 12.47 kV - 46 kV) power lines, substations, switches, poles, transformers, service drops and metering. The distribution system begins as the voltage is stepped down (e.g., 69 kV / 12.47 kV), via the substation transformer(s) and ends as the secondary service enters the customer's meter socket. Distribution circuits begin at the low-voltage side of the transformer located in the substation.

Conductors for the distribution delivery system are either located overhead on utility poles, or buried underground in the case of urban, downtown areas or new developments. Urban and suburban distribution is normally three-phase in order to serve all types of customers; residential, commercial, and industrial.

Most electric customers are connected to a transformer (pole mounted or ground level protective enclosure), which reduces the distribution voltage to the relatively low voltage used by lighting and interior wiring systems. Each customer has an "electrical service" or "service drop" connection and a meter for billing.

Section 2 - Capital Facilities Plan and Impact Fee Facilities Plan

2.1 General

As discussed above, the Impact Fee Facilities Plan ("IFFP") shall, in accordance with the Statute, identify (a) demands placed on existing public utilities by new development activity; and (b) the proposed means by which the local subdivision will meet those demands. In addition, each local political subdivision shall generally consider the revenue sources that will be used to finance the impacts on system improvements.

The IFFP, as discussed herein, is based largely on the Capital Facilities Plan Update, dated February 2022, prepared by ICPE. Certain parts of that report, which is incorporated herein by reference, are summarized in the following discussion of the CFP/IFFP.

2.2 Historical Population and Load Growth

According to the U.S. Census Bureau, the City had a population of approximately 9,521 in 2020. As depicted in the following table, the current population is the result of significant growth that occurred during the last decade (2010 – 2020).

Table 2-1
Santa Clara City Historical Population

Historical population		
Census	**Pop.**	**%±**
1960	291	
1970	271	-6.9%
1980	1,091	302.6%
1990	2,322	112.8%
2000	4,630	99.4%
2010	6,003	29.7%
(Est.) 2020	9,521	58.6%

The City consistently experienced a high rate of growth during the 80's and 90's and then slowed somewhat during the period 2000 – 2010 primarily due to the economic downturn beginning in 2008.

However, as indicated in the above table, there has been a rather high rate of growth over the period 2010 through 2020. Most of that growth has been the result of an upturn in economic conditions occurring during the past five or six years. The last several years have seen a renewed interest in development in the area and future growth is projected to be approximately 4.6% annually for the next five years or more. Because of Santa Clara City's location, continued interest of developers, favorable interest rates for investment, and the availability of manpower resources, it is expected that the relatively high growth rate will continue in the near term and should be closely monitored over the next five years. If growth accelerates above projections of system improvements must also be accelerated. The annual historical peak demand growth since 1991 is presented in the following Table 2-2.

Table 2-2
Santa Clara City
Electrical Load History

Year	Summer Peak (kW Demand)
1991	3,042
1995	4,802
2000	7,639
2001	7,253
2002	8,987
2003	10,142
2004	10,427
2005	11,980
2006	12,030
2007	12,880
2008	12,430
2009	13,310
2010	12,770
2011	12,800
2012	13,900
2013	13,970
2014	13,150
2015	13,650
2016	14,983
2017	15,220
2018	16,128
2019	16,138
2020	18,636
2021	20,172

2.3 Existing Electric Infrastructure and Future Needs

2.3.1 Generation

Santa Clara City has an existing power plant with two (2) 2MW generator units. The Plant, as constructed, has the infrastructure to add four (4) additional units. The plant was initially installed to cover peak spiking periods and with the recognition that future units would likely be required due to load growth.

Review of Santa Clara's resources mix shows that during high loadings hours Santa Clara has a resource short fall that will continued to grow with load growth. Obtaining resource to cover peak spiking can be very costly and difficult to predict from a budgetary perspective. As a means to control costs, generation should be considered for installation during the 2022-2024 period of this CFP. In conjunction with the 2.5 MW unit (Unit 3) that was recommended for installation under the previous study, installation of Unit 4 (2.5 MW) and Unit 5 (2.5 MW) is recommended for installation during this CFP period.

In conjunction with Unit 5 addition, an equipment building will be needed as the existing Unit 5 bay is currently serving as equipment storage.

2.3.2 Transmission

Santa Clara City's 69 kV electrical system receives power from a radial 69 kV UAMPS owned transmission line that is also interconnected to St. George City's electrical system. The City's 69 kV electrical system can also receive power from a "normal open" interconnection with Rocky Mountain Power at its Red Mountain interconnection point on an emergency basis. The UAMPS line connects to Santa Clara City's 69 kV transmission systems near the Parley Hassell Substation on the east side of the City. The City has two substations, Paul Grimshaw in the northwest area of the city and Parley Hassell located in the southeast area. The City-owned 69 kV transmission line runs from the Parley Hassell Substation to the Paul Grimshaw Substation, then west and south to the normal open PacifiCorp interconnection point on the western City boundary. The line then proceeds southward to the city's power plant and on to a future substation site.

The majority of the City's existing sub-transmission system was built in 1993. The 69 kV sub-transmission system is constructed with 4/0 AWG ACSR conductor. Past studies have utilized a maximum capacity of 28 MVA during extreme heat conditions, for the 69 kV sub-transmission systems. Based on load projections, Santa Clara loads will be at 30 MVA by 2032; if unexpectedly high growth occurs transmission loading could become a concern at an earlier date.

For normal operation and configuration, the existing sub-transmission system should serve the city's need through the 5-year period of this CFP. However, for a system outage beyond Santa Clara's system, the ability of Rocky Mountain Power system to carry the complete Santa Clara load during peak loading may be exceeded within the next four years.

As indicated Santa Clara City's electrical system is served from a radial system with approximately 30 MVA capacity; previous long-term planning, and as supported in this report, calls for addition of a third substation (south hills area) with transmission interconnection to the existing system and to an external source. Under a previous project Santa Clara City extended its 69 kV transmission system to the future substation site.

In previous years, to address projected transmission and substation requirements due to growth, Santa Clara city secured interconnection rights to St. George City's 138-69 kV Green Valley transmission substation. Interconnection to the Green Valley substation will require construction of approximately 2.3 miles of 69kV between interconnection points. Interconnection to the Green Valley substation is recommended during the period of the CFP. The future interconnection will increase system reliability and provide needed additional transmission capacity to accommodate growth. Interconnection transmission is depicted in the Long-Term Planning map included in CFP report.

2.3.3 Substations

Santa Clara City is served by a radial 69 kV line owned by UAMPS. The City has two substations, Paul Grimshaw and Parley Hassell substations. These substations step the voltage from 69 kV to 12.47 kV for distribution delivery to City customers.

Studies indicate that the existing Paul Grimshaw and Parley Hassell Substations can be used to supply near term electrical demand in the City. However, system studies also indicated that additional transformer capacity will be necessary by the 2025/2026 time frame.

From previous work, Santa Clara City Power has identified the location for a third substation near the southwest city boundary (south hill area). Through this study it is seen that the identified location is well suited to cover expected growth in the area and would also provide to facilitate backup support to adjacent circuits and substations.

With consideration of needed capacity, expected growth pattern and developing distribution constraint the installation of an additional substation is recommend occurring in the 2026-time frame.

Good engineering practice requires that the electrical system be able to withstand the loss of a single substation transformer (typically the largest on the system), without leaving any customers out of power. This is most often referred to as the "N-1" condition. In order to meet this requirement, loading of the substation transformers should not exceed the normal capacity of the substation transformer. The remaining capacity is then available to provide power to customers who would otherwise be without power when a substation transformer fails. If any one of the substation transformers in the system fails, the remaining transformers and distribution main feeder lines can continue to serve the entire load. It is critical that adequate ties are created between distribution circuits to allow load transfers from one circuit to another or from one substation to another. These interconnection points on the distribution system are best accomplished with three-phase gang-operated airbreak switches for overhead or with pad-mounted three-phase operated switchgear for underground applications.

> ***Note:*** *In cold weather, substation transformers can be temporarily loaded above the maximum rating. ANSI Standard C57.92 provides a guide for loading transformers at various temperatures. The standard indicates that if the average daily temperature is 30°F, a transformer can be loaded to about 120% of nameplate rating with the same life expectancy as if it were loaded to nameplate. If the average daily temperature exceeds 86°F, the transformer loading should be reduced below nameplate rating. Average daily temperature of 86°F is often exceeded in the Santa Clara City area. This requires that the loading on each substation transformer during the summer peaking time be maintained below the nameplate rating.*

For safe and efficient operation of the system replacement of Parley Hassell recloser controller(s) is scheduled in the coming year. Through this study it is acknowledged that controller replacement with SCADA integration is necessary.

2.3.4 Distribution

General guidelines for main feeder distribution line construction are included in the distribution section of the CFP Report. The guidelines emphasize construction of power lines with capacity to handle current and expected future load, provide backup capacity, maintain reliability, and minimize losses.

The long-range planning map included with the capital facilities plan shows prospective routes for new main feeder distribution lines. The lines typically run along existing and future road right-of-ways, as shown on the Santa Clara City General Plan.

The distribution routes on the long-range map are intended as a general guide to aid in planning new distribution facilities. Line routing will vary from the plan depending on when and where development occurs as well as the actual alignment of the roads at the time of construction.

Currently, under normal conditions, the present 12.47 kV distribution system has adequate capacity to handle existing load and ability to backup load for most contingencies. Due to known load growth, addition of 12.47 kV circuits is required as follows:

1. 0.21 mile of three phase 750 MCM URD Arrowhead to Vineyard drive. (2022-2023)
2. Extension of Paul Grimshaw circuits PRG-5 and PGR-6 approximately 0.63 miles each with 750 MCM URD northward of the Paul Grimshaw substation (2023-2024). Cost for circuits PRG-5 and PRG-6 extension are indicated to fall under the line extension policy (developer funded) and should be excluded from Impact Fee assessment.

Although outside of this CFP period, it is noted that studies show some overhead distribution circuit sections, associated with Paul Grimshaw substation PGR-1circuit, will need to be reconductored or interconnection to the recommended south hills substation in the 2028- 2030-time frame. The upgrades will be needed to address voltage drop for loss of the Paul Grimshaw power transformer contingency and timing is based on study projections.

2.4 Level of Service Standards

Santa Clara City strives to maintain and operates it system to obtain a uniform level of service throughout its system. The intent is to provide reliable power delivery at competitively low cost and equitably to all its customers. Below is a typical Level of Service Standard used for operations and to assess the need for new infrastructure.

The City should plan, designs and operates its system based on the following criteria:

- Transformer ratings under varying load levels and loading conditions must remain below their ONAN/ONFA/ONFA 65degree rating.
- The system must be able to adequately serve load under single contingency (N-1) situations, where "N" is a power system element such as a transformer or line.
- Substation loading shall be limited to allow for N-1 situations.
- The system switching required under an N-1 contingency should remain as simplified as possible to ensure that switching orders not become unnecessarily complex.
- For normal operation, transmission circuit voltage must remain between 95% and 105% of its nominal value; and
- Primary distribution circuit voltage must remain between 98% and 105% (at loads) of its nominal value; and
- Distribution circuit mains must be able to serve additional load under N-1 contingencies.
- Distribution circuit loading criteria must remain below its maximum current rating;
- System Power Factor, during peak, at substation recloser should be at 0.98 or better.

The above criteria were used in the study to determine Santa Clara City's facility needs based on the amount of load (i.e., demand) placed on the existing system over the study planning horizon.

2.5 Demands Placed on Existing Facilities

The demand placed on an electric system is typically measured in kilowatts (kW) or kilovolt-amperes (kVA) and stated as either coincident-peak ("CP") demand or non-coincident peak ("NCP") demand. The system CP demand is typically the maximum hourly demand for the entire system measured over some time period (e.g. week, month, year); i.e., the point in time where the sum of all demands placed on the system are the highest for the system as a whole. The NCP demand represents the sum of the maximum demands of individual customers or customer classes (e.g., residential, commercial, industrial) measured or estimated for a time period. The CP demand represents the combined loads across all customer classes measured at the system level where the NCP demand represents the total demand the system would be subject to if all customer classes peaked at the same time. The CP demand by definition will always be lower than the NCP demand. For purposes of determining Impact Fees, CP represents the demand placed on the existing system as a whole, while NCP reflects the maximum demand placed on local facilities by individual customer classes (e.g., residential and commercial) . The CP demand is normally the demand that a utility plans for when sizing facilities that will be used to meet future growth on the system. However, each individual piece of equipment must be able to support its own individual peak demand even if that demand does not occur at the same time as the system's CP. Therefore, it is the NCP demand that is used to determine the Base Impact Fees discussed later in Section 3.

The analysis of the City's projected demands for the CFP/IFFP one, three, six, ten, and twenty year plans through 2032, is shown in Exhibit 1 attached hereto and summarized hereunder in Table 2-3**.**

Table 2-3
Summary of CP and NCP Demands
For the Period 2022 through 2041

Description	2022 1 Year	2024 3 Year	2027 6 Year	2031 10 Year	2041 20 Year
Total System CP Demands (kW)	21,210.0	23,273.0	26,304.0	29,376.1	38,720.9
Total System NCP Demands (kW)	24,299.1	26,250.6	29,177.8	33,080.8	42,838.3

The System CP Demands for the period (2022 – 2027) were developed by ICPE and reviewed by the Consultant. The Consultant extended the planning period forecast to 2041 for purposes of the IFA. From the Load Forecast in Exhibit 1, the Estimated NCP Demands (measured at the meter) shown on lines 24-27 were computed based on the Projected Energy Sales (shown on lines 4-7) and the following assumptions and considerations:

- Residential customer growth will average approximately 90 new connections per year and was correlated to the anticipated population growth. Approximately 15 customers are assumed to be added to the Commercial class each year while no growth was assumed for the Agricultural class.
- Growth in Average Annual Usage per Customer (lines 36-38) for residential, commercial and other customer classes was assumed to be nil due to increases in appliance efficiencies and demand side management programs. However, we did increase the commercial average annual usage by 4.0 percent in 2022 to reflect anticipated usage to return to pre-pandemic levels.

- Estimated NCP Load Factors (lines 39-41) were assumed to be: Residential – 25%; Commercial – 30%; and Agricultural – 30%.
- The System Load Factor (line 3) was assumed to average 30% and approximates recent historical loading patterns for the system and was determined by historical loading.

As discussed later in Section 3, it is the estimated change (i.e., increase) in the Total System CP Demand from 2021 to 2026 that is used as the starting point for calculation of the Impact Fees. Based on FY 2021 metering data the system CP was about 20,200 kW and the total system load was 53,528,948 kWh. By dividing the system load by the number of hours in the year (8,760 hrs.) and dividing that number by the system CP we get an average system load factor of 30.25%.

2.6 System Modeling for the CFP/IFFP

The CFP/IFFP study considers the electrical load growth within the Santa Clara City Power service area. To evaluate system performance under existing and projected peak load conditions, a computer model of Santa Clara City's power system was developed using SKM software and load flow simulations performed. Computer system analysis indicates that the current level of service is within Santa Clara City Power's level of service standard and acceptable utility practice. From the simulations, and system evaluation, projects that are necessary to accommodate load growth in the next five years were identified. These projects are required to maintain the proper level of service as the load in the SCCP system increases.

Projects that are proposed in the Plan are listed in the following section with the recommended completion date and the estimated cost of the project in 2022 dollars. Actual timing of these projects may vary depending on the actual load growth of the electrical system.

The load forecast identified expected loads for existing substations, as well as the addition of an additional substation in the south hills area. Load transfers between substations were shown on the basis of maximizing the utilization of existing substation transformers. Capacity additions are only scheduled when the transfer of load to adjacent substations would result in overloading those facilities due to new growth. Maximizing the utilization of existing and future resources produces the least cost option. Distribution facilities are planned for construction in the time frames necessary to facilitate the load transfers as dictated by the system growth and identified through this study. Backup capacity for substation transformers/equipment, provisions for improved transmission and distribution reliability and addition of generation are also issues addressed in the CFP study.

Under current city boundaries, Santa Clara City has limited area for growth but can still support growth for some time. Major growth is expected to occur in the North Town Area and South Hills area (area south of the river and within city boundaries).

Long-term distribution plans identified in the CFP are intended as a guide to be followed as service is provided for new customers. Most new construction can be delayed until forecasts are certain. However, duplication and waste can be avoided if conformance to the City's master plan is verified before line improvements or extensions are made. The long-term plans are speculative and should be adapted as circumstances change, such as the location of electrical load and routing of streets. The City should use the long-term plans as a guide to assure proper Right-of-Ways are obtained as each development is approved. Another benefit of following the long-term plan is to assure that feeder cables installed will be properly sized to meet the future needs of the area. This will minimize the need to upgrade these cables in the future. Having adequate right-of-ways secured in advance will streamline the construction process for the City Power Department.

Prospective locations for main distribution feeders in Santa Clara City are shown on the Long-term Planning Map of the CFP. The map also shows existing main feeders, existing interconnection points, and proposed interconnection points between feeders. New feeder routes may need to be selected to supply load in the northeast and southwest part of the City. As these areas develop, heavy backbone feeders need to be extended along major streets. Main feeders from each substation should intersect to form a looped system. This will permit load to be transferred between substations and will establish alternate sources of power during outages or for maintenance work.

2.7 Model Results

The following Project Summary details the anticipated projects necessary to sustain the projected growth rate for Santa Clara City's electrical system for the next 5 years. Table 2-4 contains project listing, associated cost projections, and project schedule:

1. Install Arrowhead to Vineyard 12.47kV circuit extension (0.24 miles).
2. Install/replace Parley Hassell Station recloser controllers and SCADA integration.
3. Install 2-2.5MW generation units
4. Install 0.63 miles Paul Grimshaw 12.47kV circuit # PRG-5 extension (developer funded)
5. Install 0.63 miles Paul Grimshaw 12.47kV circuit # PRG-6 (developer funded).
6. Install Capacitors Banks (years 2024 and 2027)
7. Install 69kV line extension – Green Valley/Canyon View interconnection point to new South Hills Substation location.
8. Install Equipment Building.
9. Install South Hills substation
10. Install 1- 2.5 MW generation unit (2027)

There is greater confidence in projecting requirements for 2 to 3 years than there is for a 5-year outlook. However it is necessary to forecast future projects due to the magnitude (and cost) of the modifications necessary should the annual rate of growth exceeds projections. Substation, distribution, and transmission line requirements need to be addressed to meet future needs of the City in a timely fashion.

The proposed projects, as listed above and in Table 2-4, will provide a method for Santa Clara City to plan and budget for the facilities necessary to serve the anticipated electrical load growth while maintaining the current level of service.

The projects were developed based on the following parameters:

1. 4.8% load growth over existing Santa Clara City loading.
2. Substations would be served at 69 kV and the proposed new substation would be served at 69 kV by a new transmission line to be built from the Green Valley/Canyon View interconnection Point to the new substation site.
3. To minimize expenditures and the capital procurement of new equipment, existing substation transformers and equipment would be utilized as long as possible.
4. Backup capacity would have to be built into the distribution system for load transfers between substations in order to defer purchasing additional substation transformers.
5. Maintain current level of service.

TABLE 2-4
Santa Clara City
CFP and IFFP
<u>Generation, Transmission, Distribution, and Substation Projects</u>

All Estimates Are In 2022 Dollars

Item and Description	Item Cost	Total For Year		Running Total
2022/2023				
1. Install Arrowhead to Vineyard 12.47 kV URD circuit extension (0.24 miles) 2. Install/replace Parley Hassell Station Reclosure Controllers and SCADA integration. 3. Install 2-2.5 MW generation units	$120,000 $170,000 $4,600,000			
2022/2023 Total Estimate	**$4,890,000**	**$4,890,000**		**$4,890,000**
2023/2024				
1. Install Paul Grimshaw 12.47kV circuit # PGR-5 extension (0.63 miles ea.) (Developer Funded) 2. Install Paul Grimshaw 12.47kV circuit # PGR-6 extension (0.63 miles ea.) (Developer Funded) 3. Capacitor Bank(s) Installation	$404,000 $404,000 $20,000			
2023/2024 Total Estimate	**$828,000**	**$828,000**		**$5,718,000**
2025/2026				
1. Install 69kV line extension – St. George Canyon View Substation to South Hill Substation. 2. Equipment Building	$1,300,000 $300,000			
2025/2026 Total Estimate	**$1,600,000**	**$1,600,000**		**$7,318,000**
2026/2027				
1. Install South Hills Substation 2. Capacitor Bank(s) Installation 3. Install 1-2.5MW generation unit.	$2,600,000 $22,000 $2,300,000.			
2026/2027 Total Estimate	**$4,922,000**	**$4,922,000**		**$12,240,000**
2022 thru 2027 Total Estimate				**$12,240,000**

2.8 IFFP Capital Projects and Costs

As previously mentioned, the costs for the above projects are estimated in 2022 dollars. Major projected are scheduled throughout the planning period; however, growth in demand on the system generally happens in "groups" or "lumps" according to actual commercial and residential development. Because residential developments are generally in subdivision form and commercial developments are generally grouped around a single location, many of the sub-areas in the IFFP area may not realize the growth modeled; therefore, some of the projects could, in reality, be delayed until required by localized growth. In contrast, it is possible that projects may need to be accelerated if growth in an area occurs faster than anticipated.

2.9 Certification of the IFFP

I certify that the attached Impact Fee Facilities Plan:

1. includes only the costs of public facilities that are:
   a. allowed under the Impact Fees Act; and
   b. actually incurred; or
   c. projected to be incurred or encumbered within six years after the day on which each impact fee is paid;
2. does not include:
   a. costs of operation and maintenance of public facilities;
   b. costs for qualifying public facilities that will raise the level of service for facilities, through impact fees, above the level of service that is supported by existing residents;
   c. an expense for overhead, unless the expense is calculated pursuant to a methodology that is consistent with generally accepted cost accounting practices and the methodological standards set forth by the federal Office of Management and Budget for federal grant reimbursement;

CERTIFIED BY:

Signature: Mike Velarde

Name: Mike Velarde, P.E.

Title: ICPE, Senior Engineer

Date: May 16, 2022

Section 3 - Impact Fee Analysis

3.1 General

As discussed in Section 1, the IFA portion of the Statue requires that each local political subdivision intending to impose an impact fee prepare a written analysis of each impact fee. It also requires that IFA include a summary designed to be understood by a lay person. Additional requirements include identifying the estimated impacts on existing capacity and system improvements caused by the anticipated development activity. The political subdivision must also estimate the proportionate share of (i) the costs of existing capacity that will be recouped and (ii) the costs of the impacts on system improvements that are reasonably related to the new development activity.

3.2 Impact Fee Analysis

The Impact Fee Analysis involved three (3) basic steps or sub-analyses: (1) an Impact Fee Cost Analysis; (2) an Impact Fee Demand Analysis; and (3) the Calculation of the Impact Fee.

3.2.1 Identification of Impact Fee Projects/Costs

The Impact Fee Cost Analysis for current and future projects is shown in the attached Exhibit 2. Page 1, Column (a) of this exhibit shows the costs (in 2022 dollars) of the projects identified in the CFP while column (b) is a restatement of project costs in the year of the expenditure, assuming an inflation rate of 3.0 percent per annum. Column (c) shows the percentage of costs to be funded by Impact Fees. As shown in column (c), not all of the projects identified in the CFP are anticipated to be recovered through Impact Fees. Two of the projects (shown on lines 4 and 5) are anticipated to be funded by developers of the residential/commercial properties that require the construction of line extension out of the Paul Grimshaw substation. Column (d) is simply the product of columns (b) and (c). The Impact Fee projects have, by necessity, been delineated between those projects that will be funded directly through impact fees and others that will be funded from future bond financings; the total cost of which (principal and interest) will be recovered through Impact Fees over the life of the bond issue (see lines 12 - 19). One project, the installation of two 2.2 MW generating units (line 12), has already been funded through debt issued in Year 2021. The debt service associated with this project has been separately accounted for in our Impact Fee Cost Analysis shown in Exhibit 4. All other bonded projects (lines 14, 16 and 17) are assumed to be funded by new debt to be issued in the future. The total amount of project costs to be recovered through Impact Fees as shown in Exhibit 2 is summarized in the following Table 3-1.

Table 3-1
Total Costs of Current and Future Projects
To Be Funded through Impact Fees

Description	Total Cost
Projects Directly Funded Through Impact Fees	$662,631
Projects Funded Through Bond Financings *	11,502,279
Total Project Costs	$12,164,910

* Dollar amount shown excludes interest on debt.

3.2.2 Impact Fee Demand Analysis

The Impact Fee Demand Analysis is presented in Exhibit 3. This analysis calculates the Demand Placed on the Existing System to be used as the denominator in determining the Impact Fee by customer class (i.e., Residential, Commercial and Agricultural) and for the total system. The first step was to determine the increase in the CP demand over two distinct recovery periods: a 5-year Recovery Period (2022 – 2026) and a 20-year Recovery Period (2022 – 2041). A 20-year Recovery Period was used all the projects funded through existing and future bond financings. The increase in CP Demand is shown on line 3 of Exhibit 3 which, for the total system, is 5,093.0 kW for the 5-year Recovery Period and 18,520.9 kW for the 20-year Recovery Period. The increase in total system NCP demand (at the meter) is 5,031.4 and 19,667.6 over the 5-year and 20-year recovery periods, respectively (see line 8). Lines 9-13 of show the increase in customers over the two planning horizons and the estimated average CP demand and NCP demand placed on the system per customer added. The NCP demand per customer provides the basis for determining the customer panel utilization percentages used in the Proposed Impact Fee for each customer classification, discussed below. You will notice that for the Agricultural customer class, it has been assumed there will be no increase in number customers or demand over the entire 20-year forecast. The Impact Fee Demand Analysis is summarized in Table 3-2 below.

Table 3-2
Impact Fee Demand Analysis
By Customer Class and Total System

Description	5-Year Recovery Period	20-Year Recovery Period
NCP Demand at Meter (kW)		
Residential	2,933.5	11,733.9
Commercial	2,097.9	7,933.7
Total System NCP Demands (kW)	5,031.4	19,667.8

3.2.3 Calculation of the Impact Fee

The calculation of the Base Impact Fee is presented in Exhibit 4 and summarized below in Table 3-3. Lines 1-8 of Exhibit 4 reflect the total Impact Fee project costs to be recovered for Future and Current Projects over the two recovery periods. These costs include the project financing costs (lines 3 and 6) applicable to the bonded projects. Two additional adjustments (lines 9 and 10) were made in order to determine the net project costs to be recovered through impact fees. The first adjustment was to add unrecovered historical growth-related projects; that is, past impact fee projects for which the total cost has yet to be recovered. Only one such project (i.e., the City Administration Building) was identified as being growth-related and having unrecovered project costs. SCCP is responsible for the department's share of the cost to construct the existing City Hall and Administration Building. Based on information provided by the City, the Power Department's unrecovered share is of the subject costs is $175,934. The second adjustment was to subtract the current balance of unused Impact Fee funds which amounts to $2,120,044. After making the two adjustments, it resulted in the total net project costs to be recovered through Impact Fees shown on line 11. The amounts on line 11 were then restated at various recovery levels (100%, 75% and 50%) as presented on lines 12-14. The various recovery levels are designed to allow the City Council to consider the appropriate Impact Fee it wishes to implement, taking into account such things as economic development goals and the residual effect on electric rates (i.e., the portion of project costs that are not recovered from Impact Fees will need to be recovered through electric rates).

The increase in NCP demand measured at the meter is shown on lines 15 through 17; the total of which is used as the denominator for calculating the base impact fee. The base impact fee at various recovery levels is presented on lines 18 through 20 and is simply determined as the total impact fee project costs to be recovered (lines 12 – 14) divided by the increase in total system NCP demand (line 17). Following is a summary of the calculation of the base impact free at the various recovery levels.

Table 3-3
Summary of the
Base Impact Fee Calculation

Description	5-Year Recovery Period	20-Year Recovery Period	Total
Total Project Costs to be Recovered			
100%	$662,631	$10,928,965	$11,591,596
75%	496,973	8,196,724	8,693,697
50%	331,316	5,464,482	5,795,798
Total System NCP Demands (kW)	5,031.4	19,667.6	
Base Impact Fee ($/kW)			
100%	$131.70	$555.68	$687.38
75%	98.77	416.76	515.54
50%	65.85	277.84	343.69

3.3 Impact Fee Charges – Present and Proposed

A summary of Impact Fee charges for the Residential and Commercial customer classes is provided in the attached Exhibit 5. The estimated charges, by selected electric panel size, have been calculated under each of the proposed Impact Fees as compared to the current Impact Fee. The calculation of the Impact Fee charge is based on the following:

Equation 1 – Single Phase Service:

$$Impact\ Fee\ Charge\ = IF_b\ \times PUF \times \left(PS\ \times \left(\frac{V}{1{,}000}\right) \times PF\right)$$

Where: IF_b = Base Impact Fee

PUF = Average Panel Utilization Factor

PS = Panel Size (amperage)

V = Line-to-line Voltage

PF = Estimated Power Factor

Equation 2 – Three Phase Service:

$$Impact\ Fee\ Charge\ = IF_b\ \times PUF \times \left(\sqrt{3} \times PS\ \times \left(\frac{V}{1{,}000}\right) \times PF\right)$$

Where: IF_b = Base Impact Fee

PUF = Average Panel Utilization Factor

PS = Panel Size (amperage)

V = Line-to-line Voltage

$\sqrt{3}$ = 1.732

PF = Estimated Power Factor

The Panel Utilization Factor (15.0% - Residential; 17.5% - Commercial) shown on lines 2 and 3 of Exhibit 5 are based on the estimated per-customer NCP demand calculated on Exhibit 1. The Power Factor (90% - Residential; 85% - Commercial) was determined from research of available industry literature.

Charges under the currently effective Impact Fee schedules, shown under column (a) of Exhibit 5, are calculated using a base fee of $586.11 per kW (based on the data and information contained the previous SCCP Impact Fee Study). Charges calculated based on the Proposed Impact Fee under each of the assumed recovery levels is shown in columns (b) through (d) of Exhibit 5.

3.4 Certification of the IFA

I certify that the attached Impact Fee Analysis:

1. includes only the costs of public facilities that are:
    a. allowed under the Impact Fees Act; and
    b. actually incurred; or
    c. projected to be incurred or encumbered within six years after the day on which each impact fee is paid;
2. does not include:
    a. costs of operation and maintenance of public facilities;
    b. costs for qualifying public facilities that will raise the level of service for facilities, through impact fees, above the level of service that is supported by existing residents;
    c. an expense for overhead, unless the expense is calculated pursuant to a methodology that is consistent with generally accepted cost accounting practices and the methodological standards set forth by the federal Office of Management and Budget for federal grant reimbursement; and
3. offsets costs with grants or other alternate sources of payment; and
4. complies in each and every relevant respect with the Impact Fees Act.

CERTIFIED BY:

Signature ____________________

Name: Robert E. Pender, ASA

Title: President

Company: R. E. Pender, Inc.

Date: May 16, 2022

APPENDIX A
UTAH STATUTE U.C.A. 1953 § 11-36A-102

West's Utah Code Annotated Currentness
Title 11. Cities, Counties, and Local Taxing Units
Chapter 36A. Impact Fees Act
Part 1. General Provisions
§ 11-36a-102. Definitions

As used in this chapter:

(1)(a) “Affected entity” means each county, municipality, local district under Title 17B, Limited Purpose Local Government Entities--Local Districts, special service district under Title 17D, Chapter 1, Special Service District Act, school district, interlocal cooperation entity established under Chapter 13, Interlocal Cooperation Act, and specified public utility:

(i) whose services or facilities are likely to require expansion or significant modification because of the facilities proposed in the proposed impact fee facilities plan; or

(ii) that has filed with the local political subdivision or private entity a copy of the general or long-range plan of the county, municipality, local district, special service district, school district, interlocal cooperation entity, or specified public utility.

(b) “Affected entity” does not include the local political subdivision or private entity that is required under Section 11-36a-501 to provide notice.

(2) “Charter school” includes:

(a) an operating charter school;

(b) an applicant for a charter school whose application has been approved by a chartering entity as provided in Title 53A, Chapter 1a, Part 5, The Utah Charter Schools Act; and

(c) an entity that is working on behalf of a charter school or approved charter applicant to develop or construct a charter school building.

(3) “Development activity” means any construction or expansion of a building, structure, or use, any change in use of a building or structure, or any changes in the use of land that creates additional demand and need for pub-

lic facilities.

(4) “Development approval” means:

(a) except as provided in Subsection (4)(b), any written authorization from a local political subdivision that authorizes the commencement of development activity;

(b) development activity, for a public entity that may develop without written authorization from a local political subdivision;

(c) a written authorization from a public water supplier, as defined in Section 73-1-4, or a private water company:

(i) to reserve or provide:

(A) a water right;

(B) a system capacity; or

(C) a distribution facility; or

(ii) to deliver for a development activity:

(A) culinary water; or

(B) irrigation water; or

(d) a written authorization from a sanitary sewer authority, as defined in Section 10-9a-103:

(i) to reserve or provide:

(A) sewer collection capacity; or

(B) treatment capacity; or

(ii) to provide sewer service for a development activity.

(5) “Enactment” means:

(a) a municipal ordinance, for a municipality;

(b) a county ordinance, for a county; and

(c) a governing board resolution, for a local district, special service district, or private entity.

(6) “Encumber” means:

(a) a pledge to retire a debt; or

(b) an allocation to a current purchase order or contract.

(7) “Hookup fee” means a fee for the installation and inspection of any pipe, line, meter, or appurtenance to connect to a gas, water, sewer, storm water, power, or other utility system of a municipality, county, local district, special service district, or private entity.

(8)(a) “Impact fee” means a payment of money imposed upon new development activity as a condition of development approval to mitigate the impact of the new development on public infrastructure.

(b) “Impact fee” does not mean a tax, a special assessment, a building permit fee, a hookup fee, a fee for project improvements, or other reasonable permit or application fee.

(9) “Impact fee analysis” means the written analysis of each impact fee required by Section 11-36a-303.

(10) “Impact fee facilities plan” means the plan required by Section 11-36a-301.

(11)(a) “Local political subdivision” means a county, a municipality, a local district under Title 17B, Limited Purpose Local Government Entities--Local Districts, or a special service district under Title 17D, Chapter 1, Special Service District Act.

(b) “Local political subdivision” does not mean a school district, whose impact fee activity is governed by Section 53A-20-100. 5.

(12) “Private entity” means an entity with private ownership that provides culinary water that is required to be used as a condition of development.

(13)(a) “Project improvements” means site improvements and facilities that are:

(i) planned and designed to provide service for development resulting from a development activity;

(ii) necessary for the use and convenience of the occupants or users of development resulting from a development activity; and

(iii) not identified or reimbursed as a system improvement.

(b) “Project improvements” does not mean system improvements.

(14) “Proportionate share” means the cost of public facility improvements that are roughly proportionate and reasonably related to the service demands and needs of any development activity.

(15) “Public facilities” means only the following impact fee facilities that have a life expectancy of 10 or more years and are owned or operated by or on behalf of a local political subdivision or private entity:

(a) water rights and water supply, treatment, and distribution facilities;

(b) wastewater collection and treatment facilities;

(c) storm water, drainage, and flood control facilities;

(d) municipal power facilities;

(e) roadway facilities;

(f) parks, recreation facilities, open space, and trails;

(g) public safety facilities; or

(h) environmental mitigation as provided in Section 11-36a-205.

(16)(a) “Public safety facility” means:

(i) a building constructed or leased to house police, fire, or other public safety entities; or

(ii) a fire suppression vehicle costing in excess of $500,000.

(b) “Public safety facility” does not mean a jail, prison, or other place of involuntary incarceration.

(17)(a) “Roadway facilities” means a street or road that has been designated on an officially adopted subdivision plat, roadway plan, or general plan of a political subdivision, together with all necessary appurtenances.

(b) “Roadway facilities” includes associated improvements to a federal or state roadway only when the associated improvements:

(i) are necessitated by the new development; and

(ii) are not funded by the state or federal government.

(c) “Roadway facilities” does not mean federal or state roadways.

(18)(a) “Service area” means a geographic area designated by a local political subdivision on the basis of sound planning or engineering principles in which a defined set of public facilities provides service within the area.

(b) “Service area” may include the entire local political subdivision.

(19) “Specified public agency” means:

(a) the state;

(b) a school district; or

(c) a charter school.

(20)(a) “System improvements” means:

(i) existing public facilities that are:

(A) identified in the impact fee analysis under Section 11-36a-304; and

(B) designed to provide services to service areas within the community at large; and

(ii) future public facilities identified in the impact fee analysis under Section 11-36a-304 that are intended to provide services to service areas within the community at large.

(b) “System improvements” does not mean project improvements.

CREDIT(S)

U.C.A. 1953 § 11-36a-102, UT ST § 11-36a-102

Current through 2011 Third Special Session.

END OF DOCUMENT

West's Utah Code Annotated Currentness
Title 11. Cities, Counties, and Local Taxing Units
Chapter 36A. Impact Fees Act
Part 3. Establishing an Impact Fee
§ 11-36a-301. Impact fee facilities plan

(1) Before imposing an impact fee, each local political subdivision or private entity shall, except as provided in Subsection (3), prepare an impact fee facilities plan to determine the public facilities required to serve development resulting from new development activity.

(2) A municipality or county need not prepare a separate impact fee facilities plan if the general plan required by Section 10-9a-401 or 17-27a-401, respectively, contains the elements required by Section 11-36a-302.

(3)(a) A local political subdivision with a population, or serving a population, of less than 5,000 as of the last federal census need not comply with the impact fee facilities plan requirements of this part, but shall ensure that:

(i) the impact fees that the local political subdivision imposes are based upon a reasonable plan; and

(ii) each applicable notice required by this chapter is given.

(b) Subsection (3)(a) does not apply to a private entity.

CREDIT(S)

U.C.A. 1953 § 11-36a-301, UT ST § 11-36a-301

Current through 2011 Third Special Session.

END OF DOCUMENT

West's Utah Code Annotated Currentness
Title 11. Cities, Counties, and Local Taxing Units
Chapter 36A. Impact Fees Act
Part 3. Establishing an Impact Fee

§ 11-36a-302. Impact fee facilities plan requirements--Limitations--School district or charter school

(1) An impact fee facilities plan shall identify:

(a) demands placed upon existing public facilities by new development activity; and

(b) the proposed means by which the local political subdivision will meet those demands.

(2) In preparing an impact fee facilities plan, each local political subdivision shall generally consider all revenue sources, including impact fees and anticipated dedication of system improvements, to finance the impacts on system improvements.

(3) A local political subdivision or private entity may only impose impact fees on development activities when the local political subdivision's or private entity's plan for financing system improvements establishes that impact fees are necessary to achieve an equitable allocation to the costs borne in the past and to be borne in the future, in comparison to the benefits already received and yet to be received.

(4)(a) Subject to Subsection (4)(c), the impact fee facilities plan shall include a public facility for which an impact fee may be charged or required for a school district or charter school if the local political subdivision is aware of the planned location of the school district facility or charter school:

(i) through the planning process; or

(ii) after receiving a written request from a school district or charter school that the public facility be included in the impact fee facilities plan.

(b) If necessary, a local political subdivision or private entity shall amend the impact fee facilities plan to reflect a public facility described in Subsection (4)(a).

(c)(i) In accordance with Subsections 10-9a-305(4) and 17-27a-305(4), a local political subdivision may not require a school district or charter school to participate in the cost of any roadway or sidewalk.

(ii) Notwithstanding Subsection (4)(c)(i), if a school district or charter school agrees to build a roadway or sidewalk, the roadway or sidewalk shall be included in the impact fee facilities plan if the local jurisdiction has an impact fee facilities plan for roads and sidewalks.

CREDIT(S)

U.C.A. 1953 § 11-36a-302, UT ST § 11-36a-302

Current through 2011 Third Special Session.

END OF DOCUMENT

West's Utah Code Annotated Currentness
Title 11. Cities, Counties, and Local Taxing Units
Chapter 36A. Impact Fees Act
Part 3. Establishing an Impact Fee
§ 11-36a-303. Impact fee analysis

(1) Subject to the notice requirements of Section 11-36a-504, each local political subdivision or private entity intending to impose an impact fee shall prepare a written analysis of each impact fee.

(2) Each local political subdivision or private entity that prepares an impact fee analysis under Subsection (1) shall also prepare a summary of the impact fee analysis designed to be understood by a lay person.

CREDIT(S)

U.C.A. 1953 § 11-36a-303, UT ST § 11-36a-303

Current through 2011 Third Special Session.

END OF DOCUMENT

West's Utah Code Annotated Currentness
Title 11. Cities, Counties, and Local Taxing Units
Chapter 36A. Impact Fees Act
Part 3. Establishing an Impact Fee
§ 11-36a-304. Impact fee analysis requirements

(1) An impact fee analysis shall:

(a) identify the anticipated impact on or consumption of any existing capacity of a public facility by the anticipated development activity;

(b) identify the anticipated impact on system improvements required by the anticipated development activity to maintain the established level of service for each public facility;

(c) subject to Subsection (2), demonstrate how the anticipated impacts described in Subsections (1)(a) and (b) are reasonably related to the anticipated development activity;

(d) estimate the proportionate share of:

(i) the costs for existing capacity that will be recouped; and

(ii) the costs of impacts on system improvements that are reasonably related to the new development activity; and

(e) based on the requirements of this chapter, identify how the impact fee was calculated.

(2) In analyzing whether or not the proportionate share of the costs of public facilities are reasonably related to the new development activity, the local political subdivision or private entity, as the case may be, shall identify, if applicable:

(a) the cost of each existing public facility that has excess capacity to serve the anticipated development resulting from the new development activity;

(b) the cost of system improvements for each public facility;

(c) other than impact fees, the manner of financing for each public facility, such as user charges, special assessments, bonded indebtedness, general taxes, or federal grants;

(d) the relative extent to which development activity will contribute to financing the excess capacity of and system improvements for each existing public facility, by such means as user charges, special assessments, or payment from the proceeds of general taxes;

(e) the relative extent to which development activity will contribute to the cost of existing public facilities and system improvements in the future;

(f) the extent to which the development activity is entitled to a credit against impact fees because the development activity will dedicate system improvements or public facilities that will offset the demand for system improvements, inside or outside the proposed development;

(g) extraordinary costs, if any, in servicing the newly developed properties; and

(h) the time-price differential inherent in fair comparisons of amounts paid at different times.

CREDIT(S)

U.C.A. 1953 § 11-36a-304, UT ST § 11-36a-304

Current through 2011 Third Special Session.

END OF DOCUMENT

West's Utah Code Annotated Currentness
Title 11. Cities, Counties, and Local Taxing Units
Chapter 36A. Impact Fees Act
Part 3. Establishing an Impact Fee
§ 11-36a-305. Calculating impact fees

(1) In calculating an impact fee, a local political subdivision or private entity may include:

(a) the construction contract price;

(b) the cost of acquiring land, improvements, materials, and fixtures;

(c) the cost for planning, surveying, and engineering fees for services provided for and directly related to the construction of the system improvements; and

(d) for a political subdivision, debt service charges, if the political subdivision might use impact fees as a revenue stream to pay the principal and interest on bonds, notes, or other obligations issued to finance the costs of the system improvements.

(2) In calculating an impact fee, each local political subdivision or private entity shall base amounts calculated under Subsection (1) on realistic estimates, and the assumptions underlying those estimates shall be disclosed in the impact fee analysis.

CREDIT(S)

U.C.A. 1953 § 11-36a-305, UT ST § 11-36a-305

Current through 2011 Third Special Session.

END OF DOCUMENT

West's Utah Code Annotated Currentness
Title 11. Cities, Counties, and Local Taxing Units
Chapter 36A. Impact Fees Act
Part 3. Establishing an Impact Fee
→→ § 11-36a-306. Certification of impact fee analysis

(1) An impact fee facilities plan shall include a written certification from the person or entity that prepares the impact fee facilities plan that states the following:

"I certify that the attached impact fee facilities plan:

1. includes only the costs of public facilities that are:

a. allowed under the Impact Fees Act; and

b. actually incurred; or

c. projected to be incurred or encumbered within six years after the day on which each impact fee is paid;

2. does not include:

a. costs of operation and maintenance of public facilities;

b. costs for qualifying public facilities that will raise the level of service for the facilities, through impact fees, above the level of service that is supported by existing residents;

c. an expense for overhead, unless the expense is calculated pursuant to a methodology that is consistent with generally accepted cost accounting practices and the methodological standards set forth by the federal Office of Management and Budget for federal grant reimbursement; and

3. complies in each and every relevant respect with the Impact Fees Act."

(2) An impact fee analysis shall include a written certification from the person or entity that prepares the impact fee analysis which states as follows:

"I certify that the attached impact fee analysis:

1. includes only the costs of public facilities that are:

   a. allowed under the Impact Fees Act; and

   b. actually incurred; or

   c. projected to be incurred or encumbered within six years after the day on which each impact fee is paid;

2. does not include:

   a. costs of operation and maintenance of public facilities;

   b. costs for qualifying public facilities that will raise the level of service for the facilities, through impact fees, above the level of service that is supported by existing residents;

   c. an expense for overhead, unless the expense is calculated pursuant to a methodology that is consistent with generally accepted cost accounting practices and the methodological standards set forth by the federal Office of Management and Budget for federal grant reimbursement;

3. offsets costs with grants or other alternate sources of payment; and

4. complies in each and every relevant respect with the Impact Fees Act."

CREDIT(S)

U.C.A. 1953 § 11-36a-306, UT ST § 11-36a-306

Current through 2011 Third Special Session.

END OF DOCUMENT

EXHIBITS

EXHIBIT 1

FORECAST OF CUSTOMERS, ENERGY AND DEMANDS, 2016 - 2035

Santa Clara City Power
2022 Impact Fee Analysis

Forecasted Customers, Energy and Demands
For Years 2022 - 2041

Line No.	Description		Actual 2021	Forecast Period (Fiscal Year) 1 2022	2 2023	3 2024	4 2025	5 2026	6 2027	7 2028	8 2029	9 2030	10 2031
1	System Coincident Peak Demand [1]	kW	20,200.0	21,210.0	22,271.0	23,273.0	24,320.0	25,293.0	26,304.0	27,040.5	27,797.6	28,576.0	29,376.1
2	Total System Energy (Input to Distribution System) [2]	kWh	53,528,948	56,248,706	58,603,089	60,957,472	63,311,856	65,666,239	68,020,623	70,375,006	72,729,389	75,083,773	77,438,156
3	System Load Factor	%	30.25%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
	Energy Sales at Meter [3]												
4	Residential	kWh	42,386,161	43,671,023	44,955,884	46,240,746	47,525,608	48,810,470	50,095,331	51,380,193	52,665,055	53,949,917	55,234,778
5	Commercial	kWh	10,027,718	11,451,261	12,473,695	13,496,129	14,518,563	15,540,997	16,563,431	17,585,865	18,608,299	19,630,733	20,653,167
6	Agricultural	kWh	1,448	1,448	1,448	1,448	1,448	1,448	1,448	1,448	1,448	1,448	1,448
7	Total	kWh	52,415,327	55,123,731	57,431,027	59,738,323	62,045,619	64,352,914	66,660,210	68,967,506	71,274,802	73,582,097	75,889,393
8	System Energy Loss Factor [4]	%	2.08%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
	Number of Customers [5]												
	Average												
9	Residential	#	2,969	3,059	3,149	3,239	3,329	3,419	3,509	3,599	3,689	3,779	3,869
10	Commercial	#	153	168	183	198	213	228	243	258	273	288	303
11	Agricultural	#	3	3	3	3	3	3	3	3	3	3	3
12	Total	#	3,125	3,230	3,335	3,440	3,545	3,650	3,755	3,860	3,965	4,070	4,175
	Average Annual Usage Per Customer [6]												
13	Residential	kWh/Cust.	14,276.2	14,276.2	14,276.2	14,276.2	14,276.2	14,276.2	14,276.2	14,276.2	14,276.2	14,276.2	14,276.2
14	Commercial	kWh/Cust.	65,540.6	68,162.3	68,162.3	68,162.3	68,162.3	68,162.3	68,162.3	68,162.3	68,162.3	68,162.3	68,162.3
15	Agricultural	kWh/Cust.	482.7	482.7	482.7	482.7	482.7	482.7	482.7	482.7	482.7	482.7	482.7
	Coincident Peak Demand Allocation [7]												
16	Residential	kW	16,873.0	17,406.1	18,088.2	18,719.5	19,384.7	19,988.9	20,621.6	21,039.2	21,474.2	21,926.8	22,396.8
17	Commercial	kW	3,326.5	3,803.5	4,182.4	4,553.0	4,934.8	5,303.6	5,681.9	6,000.9	6,323.0	6,648.7	6,978.8
18	Agricultural	kW	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
19	Total	kW	20,200.0	21,210.0	22,271.0	23,273.0	24,320.0	25,293.0	26,304.0	27,040.5	27,797.6	28,576.0	29,376.1
								5,093					
	Average CP Demand Per Customer												
20	Residential	kW	5.7	5.7	5.7	5.8	5.8	5.8	5.9	5.8	5.8	5.8	5.8
21	Commercial	kW	21.7	22.6	22.9	23.0	23.2	23.3	23.4	23.3	23.2	23.1	23.0
22	Agricultural	kW	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
23	Total	kW	6.5	6.6	6.7	6.8	6.9	6.9	7.0	7.0	7.0	7.0	7.0
	Estimated NCP Demand at Meter [8]												
24	Residential	kW	19,354.4	19,941.1	20,527.8	21,114.5	21,701.2	22,287.9	22,874.6	23,461.3	24,048.0	24,634.7	25,221.4
25	Commercial	kW	3,815.7	4,357.4	4,746.5	5,135.5	5,524.6	5,913.6	6,302.7	6,691.7	7,080.8	7,469.8	7,858.9
26	Agricultural	kW	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
27	Total	kW	23,170.7	24,299.1	25,274.8	26,250.6	27,226.3	28,202.1	29,177.8	30,153.6	31,129.3	32,105.1	33,080.8
28	System Coincidence Factor [9]	%	85.4%	85.5%	86.4%	86.9%	87.5%	87.9%	88.3%	87.9%	87.5%	87.2%	87.0%

Santa Clara City Power
2022 Impact Fee Analysis

Forecasted Customers, Energy and Demands
For Years 2022 - 2041

Line No.	Description		Actual 2021	1 2022	2 2023	3 2024	4 2025	5 2026	6 2027	7 2028	8 2029	9 2030	10 2031
				Forecast Period (Fiscal Year)									
	Average NCP Per Customer												
29	Residential	kW/Cust.	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
30	Commercial	kW/Cust.	24.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9
31	Agricultural	kW/Cust.	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
32	Total	kW/Cust.	7.4	7.5	7.6	7.6	7.7	7.7	7.8	7.8	7.9	7.9	7.9
	Avg. Number of Customers Added Per Year [10]												
33	Residential			90	90	90	90	90	90	90	90	90	90
34	Commercial			15	15	15	15	15	15	15	15	15	15
35	Agricultural			-	-	-	-	-	-	-	-	-	-
	Estimated Increase in Average Usage Per Customer [11]												
36	Residential			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	Commercial			4.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
38	Agricultural			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Estimated Class NCP Load Factor [12]												
39	Residential		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
40	Commercial		30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
41	Agricultural		30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%

Footnotes shown on page 5.

Santa Clara City Power
2022 Impact Fee Analysis

Forecasted Customers, Energy and Demands
For Years 2022 - 2041

Line No.	Description		Forecast Period 11 2032	12 2033	13 2034	14 2035	15 2036	16 2037	17 2038	18 2039	19 2040	20 2041	Annual Growth Rate
1	System Coincident Peak Demand [1]	kW	30,200.0	31,045.6	31,914.9	32,808.5	33,727.1	34,671.5	35,642.3	36,640.3	37,666.2	38,720.9	3.22%
2	Total System Energy (Input to Distribution System) [2]	kWh	79,792,540	82,146,923	84,501,306	86,855,690	89,210,073	91,564,456	93,918,840	96,273,223	98,627,607	100,981,990	3.13%
3	System Load Factor	%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	
	Energy Sales at Meter [3]												
4	Residential	kWh	56,519,640	57,804,502	59,089,364	60,374,225	61,659,087	62,943,949	64,228,810	65,513,672	66,798,534	68,083,396	2.36%
5	Commercial	kWh	21,675,601	22,698,035	23,720,469	24,742,903	25,765,337	26,787,771	27,810,205	28,832,639	29,855,073	30,877,507	5.36%
6	Agricultural	kWh	1,448	1,448	1,448	1,448	1,448	1,448	1,448	1,448	1,448	1,448	0.00%
7	Total	kWh	78,196,689	80,503,984	82,811,280	85,118,576	87,425,872	89,733,167	92,040,463	94,347,759	96,655,055	98,962,350	3.13%
8	System Energy Loss Factor [4]	%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
	Number of Customers [5]												
	Average												
9	Residential	#	3,959	4,049	4,139	4,229	4,319	4,409	4,499	4,589	4,679	4,769	2.36%
10	Commercial	#	318	333	348	363	378	393	408	423	438	453	5.36%
11	Agricultural	#	3	3	3	3	3	3	3	3	3	3	0.00%
12	Total	#	4,280	4,385	4,490	4,595	4,700	4,805	4,910	5,015	5,120	5,225	2.56%
	Average Annual Usage Per Customer [6]												
13	Residential	kWh/Cust.	14,276.2	14,276.2	14,276.2	14,276.2	14,276.2	14,276.2	14,276.2	14,276.2	14,276.2	14,276.2	0.00%
14	Commercial	kWh/Cust.	68,162.3	68,162.3	68,162.3	68,162.3	68,162.3	68,162.3	68,162.3	68,162.3	68,162.3	68,162.3	0.00%
15	Agricultural	kWh/Cust.	482.7	482.7	482.7	482.7	482.7	482.7	482.7	482.7	482.7	482.7	0.00%
	Coincident Peak Demand Allocation [7]												
16	Residential	kW	22,885.6	23,391.0	23,914.4	24,455.8	25,015.6	25,594.1	26,191.4	26,808.0	27,444.1	28,100.2	2.55%
17	Commercial	kW	7,314.0	7,654.1	8,000.0	8,352.2	8,711.0	9,077.0	9,450.4	9,831.8	10,221.6	10,620.1	5.55%
18	Agricultural	kW	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.00%
19	Total	kW	30,200.0	31,045.6	31,914.9	32,808.5	33,727.1	34,671.5	35,642.3	36,640.3	37,666.2	38,720.9	3.22%
	Average CP Demand Per Customer												
20	Residential	kW	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.9	5.9	
21	Commercial	kW	23.0	23.0	23.0	23.0	23.0	23.1	23.2	23.2	23.3	23.4	
22	Agricultural	kW	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
23	Total	kW	7.1	7.1	7.1	7.1	7.2	7.2	7.3	7.3	7.4	7.4	
	Estimated NCP Demand at Meter [8]												
24	Residential	kW	25,808.1	26,394.7	26,981.4	27,568.1	28,154.8	28,741.5	29,328.2	29,914.9	30,501.6	31,088.3	2.36%
25	Commercial	kW	8,247.9	8,637.0	9,026.1	9,415.1	9,804.2	10,193.2	10,582.3	10,971.3	11,360.4	11,749.4	5.36%
26	Agricultural	kW	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.00%
27	Total	kW	34,056.6	35,032.3	36,008.0	36,983.8	37,959.5	38,935.3	39,911.0	40,886.8	41,862.5	42,838.3	3.03%
28	System Coincidence Factor [9]	%	86.9%	86.8%	86.9%	86.9%	87.1%	87.3%	87.5%	87.8%	88.2%	88.6%	87.3%

Santa Clara City Power
2022 Impact Fee Analysis

Forecasted Customers, Energy and Demands
For Years 2022 - 2041

Line No.	Description		Forecast Period 11 2032	12 2033	13 2034	14 2035	15 2036	16 2037	17 2038	18 2039	19 2040	20 2041	Annual Growth Rate
	Average NCP Per Customer												
29	Residential	kW/Cust.	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	0.00%
30	Commercial	kW/Cust.	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	0.00%
31	Agricultural	kW/Cust.	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.00%
32	Total	kW/Cust.	8.0	8.0	8.0	8.0	8.1	8.1	8.1	8.2	8.2	8.2	0.45%
	Avg. Number of Customers Added Per Year [10]												
33	Residential		90	90	90	90	90	90	90	90	90	90	
34	Commercial		15	15	15	15	15	15	15	15	15	15	
35	Agricultural		-	-	-	-	-	-	-	-	-	-	
	Estimated Increase in Average Usage Per Customer [11]												
36	Residential		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
37	Commercial		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38	Agricultural		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Estimated Class NCP Load Factor [12]												
39	Residential		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	
40	Commercial		30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	
41	Agricultural		30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	

Footnotes shown on page 5.

Santa Clara City Power
2022 Impact Fee Analysis

Forecasted Customers, Energy and Demands
For Years 2022 - 2041

[1] 2022 - 2027 and 2032 per the Capital Facilities Plan, January 2022. 2028 - 2031 and 2033 - 2041 assumes a growth rate of 2.8%.
[2] Calculated based on Total Sales at Meter (line 7) and the assumed System Loss Factor (line 8).
[3] Calculated based on average number of customers and usage per customer.
[4] Assumed to be 2.0% based on the actual for 2021.
[5] Equals prior year number plus current year additions (lines 33 - 35).
[6] Based on historical average plus assumed growth in usage (lines 36-38).
[7] Allocated to various customer classes based on NCP calculations (lines 24 - 26).
[8] Annual NCP Demand based on kWh sales at meter, assumed NCP load factor and indicated loss factor.
[9] Line 1 / Line 27 after adjustment for losses.
[10] Estimated number of customers added per year.
[11] Assumes there will be no increase in average usage per customer.
[12] Residential load factor is estimated; commerical load factor is based on an analysis of data provided by the City.

EXHIBIT 2

IMPACT FEE PROJECTS / COSTS

Santa Clara City Power
2022 Impact Fee Analysis

Current and Future Impact Fee Projects / Costs

Line No.	Description of System Improvements	Estimated Total Project Costs Current $ [1]	Future $ [2]	Percent to be Funded by Impact Fees	Total Impact Fee Related Costs
		(a)	(b)	(c)	(d)
	Projects Directly Funded Through Impact Fees				
	2022-2023				
1	Install Arrowhead to Vineyard 12.47 kV URD circuit extension (0.24 miles).	$ 120,000	$ 121,787	100.00%	$ 121,787
2	Install Parley Hassell Station Reclosure Controllers and SCADA integration.	170,000	172,531	100.00%	172,531
3	Sub-total 2022-2023	290,000	294,318		294,318
	2023-2024				
4	Install Paul Grimshaw 12.47 kV circuit # PG extension (0.63 miles ea.). [3]	404,000	422,316	0.00%	-
5	Install Paul Grimshaw 12.47 kV circuit # PG-R6 extension (0.63 miles ea.). [3]	404,000	422,316	0.00%	-
6	Capacitor Bank(s) Installation.	20,000	20,907	100.00%	20,907
7	Sub-total 2023-2024	828,000	865,538		20,907
	2025-2026				
8	Equipment Building	300,000	323,009	100.00%	323,009
9	Sub-total 2025-2026	300,000	323,009		323,009
	2026-2027				
10	Capacitor Bank(s) Installation.	22,000	24,398	100.00%	24,398
11	**Total Directly Funded Projects**	**1,440,000**	**1,507,263**		**662,631**
	Projects Funded Through Bond Financings				
	2022-2023				
12	Install 2-2.2 MW genneration units.	4,600,000	4,668,490	100.00%	4,668,490
13	Sub-total 2022-2023	4,600,000	4,668,490		4,668,490
	2025-2026				
14	Install 69 kV line extension - St. George Canyon View substation to South Hill substation.	1,300,000	1,399,705	100.00%	1,399,705
15	Sub-total 2025-2026	1,300,000	1,399,705		1,399,705
	2026-2027				
16	Install South Hill Substation.	2,600,000	2,883,392	100.00%	2,883,392
17	Install 1-2.5MW generation unit.	2,300,000	2,550,693	100.00%	2,550,693
18	Sub-total 2026-2027	4,900,000	5,434,084		5,434,084
19	**Total Financed Projects**	**10,800,000**	**11,502,279**		**11,502,279**
20	**Total All Projects**	**$ 12,240,000**	**$ 13,009,542**		**$ 12,164,910**

[1] Per the City's Capital Facilities Plan, January 2022.
[2] Column (a) amounts inflated to year of construction at an est. annual rate of --> 3.00%
[3] Projects anticipated to be funded by developers.

EXHIBIT 3

IMPACT FEE DEMAND ANALYSIS

Santa Clara City Power
2022 Impact Fee Analysis

Impact Fee Demand Analysis

Line No.	Description		5-Year Recovery Period				20-Year Recovery Period			
			Residential	Commercial [2]	Agricultural	Total System	Residential	Commercial [2]	Agricultural	Total System
			(a)	(b)	(c)	(d)	(a)	(b)	(c)	(d)
	Calculation of Demand Placed on Existing System [1]									
1	CP Demand - Last Year of Recovery Period	kW	19,988.9	5,303.6	0.5	25,293.0	28,100.2	10,620.1	0.5	38,720.9
2	CP Demand - 2021 Acutal	kW	16,873.0	3,326.5	0.5	20,200.0	16,873.0	3,326.5	0.5	20,200.0
3	Increase in CP Demand at System Input	kW	3,115.9	1,977.1	(0.0)	5,093.0	11,227.2	7,293.6	(0.0)	18,520.9
4	Average System Loss Factor	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
5	Estimated Increase in CP Demand at Meter	kW	3,053.6	1,937.6	(0.0)	4,991.1	11,002.7	7,147.7	(0.0)	18,150.4
6	NCP Demand - Last Year of Recovery Period at Meter [1]	kW	22,287.9	5,913.6	0.6	28,202.1	31,088.3	11,749.43	0.6	42,838.3
7	Estimated NCP Demand - 2021 at Meter [1]		19,354.4	3,815.7	0.6	23,170.7	19,354.4	3,815.7	0.6	23,170.7
8	Estimated Increase in NCP Demand at Meter	kW	2,933.5	2,097.9	-	5,031.4	11,733.9	7,933.7	-	19,667.6
	Increase in Average Number of Customers [1]									
9	Avg. Number of Customers - Last Year of Recovery Period	#	3,419	228	3	3,650	4,769	453	3	5,225
10	Avg. Number of Customers - 2021 Actual	#	2,969	153	3	3,125	2,969	153	3	3,125
11	Increase in Average Number of Customers	#	450	75	-	525	1,800	300	-	2,100
12	Average Increase in CP Demand per Customer Added	kW	6.8	25.8	N/A	9.5	6.1	23.8	N/A	8.6
13	Average Increase in NCP Demand per Customer Added	kW	6.5	28.0	N/A	9.6	6.5	26.4	N/A	9.4

[1] Per the Impact Fee Forecast of Customers, Energy and Demands, 2022 - 2041.
[2] Commercial represents everthing non-residential (e.g., churches, schools, etc.) except Agricultural.

EXHIBIT 4

IMPACT FEE COST ANALYSIS

Santa Clara City Power
2022 Impact Fee Analysis

Impact Fee Cost Analysis

Line No.	Description		5-year Recovery Period 2022-2026	20-Year Recovery Period 2022-2041	Totals
			(a)	(b)	(c)
	Curent and Future Projects				
1	Direct Recovery Projects [1]	$	662,631	-	662,631
	Previously Bonded Projects [2]				
2	Principal	$	-	3,743,000	3,743,000
3	Interest	$	-	520,432	520,432
4	Total	$	-	4,263,432	4,263,432
	Newly Bonded Projects [3]				
5	Principal (includes debt issuance costs)	$	-	7,039,000	7,039,000
6	Interest	$	-	1,570,643	1,570,643
7	Total	$	-	8,609,643	8,609,643
8	Sub-Total Current and Future Projects	$	662,631	12,873,075	13,535,706
9	**Add: Unrecovered Historical Growth-related Projects [4]**	$		175,934	175,934
10	**Less: Balance of Unused Impact Fee Funds [5]**	$		2,120,044	2,120,044
11	**Net Project Costs to be Recovered Through Impact Fees**	$	662,631	10,928,965	11,591,596
	Assumed Impact Fee Recovery Levels				
12	100%	$	662,631	10,928,965	11,591,596
13	75%	$	496,973	8,196,724	8,693,697
14	50%	$	331,316	5,464,482	5,795,798
	Increase in NCP Demand at Meter [6]				
15	Residential	kW	2,933.5	11,733.9	
16	Commecial	kW	2,097.9	7,933.7	
17	Total	kW	5,031.4	19,667.6	
	Base Impact Fee at Various Recovery Levels				
18	100%	$/kW	131.70	555.68	687.38
19	75%	$/kW	98.77	416.76	515.54
20	50%	$/kW	65.85	277.84	343.69

[1] Based on City's Capital Facilities Plan, January 2022, see Exhibit 2.
[2] Based on an analysis of debt service for the 2021 and 2021B bond issues.
[3] Bonded Projects (i.e., new generation project) assumed to be financed with 20-year bond issue -- see attached analyses.
[4] Based on information provided by the City. Represents costs associated with the City's new City Hall and Administration building. Previous amount ($205,290) reduced to account for the number of new customers added during the period 2016 - 2021.
[5] Impact Fee Fund balance as of 02/28/2022 as provided by the City.
[6] See Exhhibit 3 - Impact Fee Demand Analysis.

Santa Clara City
2022 Impact Fee Analysis

Impact Fee Projects / Costs
Estimated Debt Service Requirements

100% Recovery

1	Total Project Costs (Impact Fee Portion)	$ 6,833,789
2	Add: Debt Issuance Costs (3.0%)	205,014
3	Total Debt Issue	7,038,803
4	Recovery Level	100%
5	Total Principal Recovery	$ 7,038,803
6	Principal	$ 7,039,000
7	Term	20
8	Interest Rate	2.00%

			1	2	3	4	5	6	7	8	9	10
	Debt Service - Years 1-10											
9	Interest Payment	$ 1,132,664	$ 140,780	$ 134,986	$ 129,076	$ 123,048	$ 116,899	$ 110,628	$ 104,230	$ 97,705	$ 91,050	$ 84,261
10	Principal Payment	3,172,158	289,702	295,496	301,406	307,434	313,583	319,855	326,252	332,777	339,432	346,221
11	Total	$ 4,304,821	$ 430,482	$ 430,482	$ 430,482	$ 430,482	$ 430,482	$ 430,482	$ 430,482	$ 430,482	$ 430,482	$ 430,482

			11	12	13	14	15	16	17	18	19	20
	Debt Service - Years 11-20											
12	Interest Payment	$ 437,979	$ 77,337	$ 70,274	$ 63,070	$ 55,722	$ 48,226	$ 40,581	$ 32,783	$ 24,829	$ 16,716	$ 8,441
13	Principal Payment	3,866,842	353,145	360,208	367,412	374,761	382,256	389,901	397,699	405,653	413,766	422,041
14	Total	$ 4,304,821	$ 430,482	$ 430,482	$ 430,482	$ 430,482	$ 430,482	$ 430,482	$ 430,482	$ 430,482	$ 430,482	$ 430,482

			21	22	23	24	25
	Debt Service - Years 21-25						
15	Interest Payment	$ -	$ -	$ -	$ -	$ -	$ -
16	Principal Payment	-	-	-	-	-	-
17	Total	$ -	$ -	$ -	$ -	$ -	$ -

	Total Debt Service	
18	Interest Payment	$ 1,570,643
19	Principal Payment	7,039,000
20	Total	$ 8,609,643

EXHIBIT 5

SUMMARY OF CHARGES

PRESENT AND PROPOSED IMPACT FEES

Santa Clara City Power
2022 Impact Fee Analysis

Summary of Charges For Residential & Commercial Customers
Current and Proposed Impact Fees

Line No.	Description / Panel Rating	Current Impact Fee	Proposed Impact Fee at Various Recovery Levels		
			100%	75%	50%
		(a)	(b)	(c)	(d)
1	***Base Impact Fee ($ per kW)***	*$ 586.11*	*$ 687.38*	*$ 515.54*	*$ 343.69*
	Assumed Panel Utilization				
2	Residential		*15.0%*	*15.0%*	*15.0%*
3	Commercial		*17.5%*	*17.5%*	*17.5%*
	Assumed Power Factor				
4	Residential		*90%*	*90%*	*90%*
5	Commercial		*85%*	*85%*	*85%*
	Impact Fee Charge for Applicable Panel Size				
	Residential (120/240, 1 phase)				
6	200 Amp	3,798	4,454	3,341	2,227
7	400 Amp	7,596	8,908	6,681	4,454
8	600 Amp	11,394	13,363	10,022	6,681
9	800 Amp	15,192	17,817	13,363	8,908
	Commercial (120/240, 1 phase)				
10	200 Amp	4,185	4,908	3,681	2,454
11	400 Amp	8,370	9,816	7,362	4,908
12	600 Amp	12,554	14,724	11,043	7,362
	Commercial (120/208, 3 phase)				
13	200 Amp	6,282	7,367	5,525	3,684
14	400 Amp	12,563	14,734	11,051	7,367
15	600 Amp	18,845	22,101	16,576	11,051
16	800 Amp	N/A	29,468	22,101	14,734
17	1200 Amp	N/A	44,203	33,152	22,101
18	1600 Amp	N/A	58,937	44,203	29,468
19	2000 Amp	N/A	73,671	55,253	36,836
20	2500 Amp	N/A	92,089	69,067	46,044
	Commercial (277/480, 3 phase)				
21	200 Amp	14,496	17,001	12,751	8,501
22	400 Amp	28,992	34,002	25,502	17,001
23	800 Amp	57,985	68,004	51,003	34,002
24	1200 Amp	86,977	102,006	76,505	51,003
25	1600 Amp	N/A	136,008	102,006	68,004
26	2000 Amp	N/A	170,010	127,508	85,005
27	2500 Amp	N/A	212,513	159,385	106,256