Benefits and Risks of Providing San José Electric Service to New Developments – A Case Study of the Downtown West Mixed-Use Development

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On November 19, 2019, City Council accepted staff's status report on priority work program areas and the associated resources needed to implement the collective direction for improved energy resiliency, which includes the evaluation and establishment of microgrids and the City of San Jose's ("City" or "CSJ") offering electric service in new areas of development. Staff have been exploring options for providing such electric service and commissioned this assessment of the Benefits and Risks of Providing San José Electric Service to New Developments – A Case Study of the Downtown West Mixed-Use Development ("Case Study") to better understand how such service could be structured. The Downtown West Mixed-Use Development ("DTW Project") proposed by Google LLC ("Developer") is a mixed-use project comprising approximately 80 contiguous acres in downtown San José. In Spring 2021, the San José City Council ("Council") took actions approving the DTW Project.[1] This Case Study describes the economic, organizational and operational requirements for the City to establish and provide electric utility service to the DTW Project using a Developer-constructed enhanced distribution system that would be more reliable, more controllable and more resilient than a traditional electric utility distribution system. The Case Study is premised on the City adopting applicable design standards and electric service rules and regulations that would allow for an advanced microgrid to accommodate more on-site distributed energy resources and improve electric reliability and resiliency. The approach described herein could be a model for the City to provide similar service to the DTW Project and other new developments within the City.

Organizational Structure

Following consideration of the benefits and risks of providing electric service to new developments, the Council would vote to adopt an ordinance to form a City owned utility ("City utility"). The City utility would provide electric service to the DTW Project upon completion of the required infrastructure coinciding with the occupancy of the structures within the DTW Project.

Funding

The customers of the City utility serving the DTW Project would not be expected to take electric service until late 2027, so the City utility would need to obtain Developer funding until such time that revenues from City utility operations are sufficient to support going forward operational costs, funding reserves and repayment of pre-operational startup costs at rates competitive with benchmark service. This Case Study also assumes that the Developer would construct and transfer, at no cost to the City, the distribution system infrastructure required to serve the DTW Project and would reimburse the City for any upstream infrastructure costs it incurs, following standard industry practice for new developments.

[1] Documents related to the DTW Project may be found at [Downtown West Mixed Use Plan Administrative Record]

Economic Analysis

Flynn Resource Consultants Inc. (Flynn), an electric industry consultant to the City, developed a model to produce financial information about the economic feasibility and performance of a City-owned and operated utility serving the DTW Project. Overall, the costs of City electric service are comparable with the benchmark utility service, with expected costs 15%-25% below the benchmark rates over the 50-year analysis.[2] Rates are expected to be competitive with the benchmark utility service during the initial 10 years of operations, with savings realized thereafter with growing DTW Project loads. Under some highly stressed scenarios with multiple overlapping negative sensitivity values, rates could exceed the baseline benchmark rates by 5% to 10%. Conversely, with favorable outcomes for several of the most impactful sensitivities, the City utility rates could be 30% to 45% below benchmark rates, as further described in the Economic Analysis section.

No attempt has been made to break down rates by customer class, including incorporation of legally mandated low-income rate requirements. These would be recommended to Council for adoption following a cost-of-service study prior to startup.

Implementation Steps

The City would need to undertake actions over a multi-year period to provide electric service to new developments. Assuming an in-service date of 2027 for the Case Study, those actions include:[3]

- Council acceptance of Case Study (Summer 2022)
- Council ordinance forming the City Utility (Fall 2022/Winter 2023)
    - Municipal code revisions
    - Business Agreement[4]
        - Defines startup costs and facility transfer
- Council approval of Design Standards (2023)
- Council approval of Interconnection Agreement (2023/24)
- Council approval of Rules & Regulations (2023/24)
- Cost of service study (2026)
- Council approval of Rates/Tariffs (2027)

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[2] SJCE Default service was selected as the benchmark product most representative of the 24/7 carbon-free product planned for the DTW project. This product's costs are likely representative of the expected costs for the 24/7 carbon-free product. Expected savings from the City utility service would be driven by lower delivery costs for the newer, more compact, underground City utility as compared to the default Investor Owned Utility (IOU) service.

[3] Utility formation steps would be taken only once. The dates shown are tentative and subject to change depending on the specific circumstances of the development.

[4] The term "Business Agreement" is provisional and provided for convenience and reference purposes only. The use of this term in this Case Study should not preclude the use of different terms or affect the interpretation of any potential future agreement(s) between developers and the City. Timing for the Business Agreement is subject to additional revisions, including potential execution after the formation of the utility. Multiple agreements could be presented to Council separately or as a single package that would be adopted in one or several meetings.

Case Study

Project Overview

This Case Study describes the economic, organizational and operational requirements for the City to establish and provide electric service to the DTW Project. The Case Study draws upon and updates previous analyses described in Appendix D of the May 17, 2021 Downtown West Project Supplemental Memorandum provided to Council,[5] planning documents, designs, load projections and other information provided by the DTW Developer, and City's outside counsel.

The DTW Project proposed by Developer is a mixed-use project comprising approximately 80 contiguous acres in downtown San José. On May 25, 2021, the Council certified the Environmental Impact Report and adopted CEQA Findings of Fact, a Statement of Overriding Considerations, and a Mitigation Monitoring and Reporting Program for the Downtown West Project. A Notice of Determination ("NOD") was filed on May 28, 2021. On June 8, 2021, the Council adopted ordinances in connection with the DTW Project.[6] Figure 1 is a plot plan of the DTW Project.

Figure 1 – DTW Project Plot Plan[7]

LEGEND

- Office
- Residential
- Land dedicated to City for affordable housing
- Land dedicated to City for Unentitled DSAP potential affordable housing
- Active use (retail, cultural, arts, education etc.)
- Parks + plazas + green spaces
- Downtown West Project Boundary

[5] Supplemental Memorandum: Additional Information Related to The Development Agreement for Google's Downtown West Project, Appendix D Electric Microgrid For The Downtown West Project, May 17, 2021

[6] Documents related to the DTW Project may be found at Downtown West Mixed Use Plan Administrative Record

[7] Plot plan from DTW Mixed Use Plan Site

Council Resolution No. 80023 contemplates that the Developer may pursue obtaining electric service for the DTW Project: i. as a private utility, ii. through a microgrid with portions owned or operated by the Investor-Owned Utility (IOU) under the jurisdiction of the CPUC, or iii. through a distribution system owned and operated by the City utility.[8] This Case Study addresses only the third option and benchmarks this option against IOU distribution service. Until Council adopts the ordinance to form the utility and the necessary agreements ("Business Agreements") are executed, the Developer would retain other service options. The Council could also adopt a standardized process in its rules and regulations for providing electric service to this and other proposed new developments.

Organizational Structure

The Council would consider an ordinance in Fall/Winter 2022 to form a City utility to provide electric service. Following budget approvals, staff would be added to a new Distribution Division of the Community Energy Department or to another Department such as Public Works. Further work would be needed to determine the organizational structure of the new Division and how it would best fit into the existing City structure. Alternatively, the City could form a separate electric utility department. In any case, it is recommended that the utility obtain services from divisions within the Community Energy Department (e.g., power procurement) and from other City departments (e.g., legal services from City Attorney's Office) for organizational efficiency and to leverage the expertise of existing City staff.

By exercising its rights under State Law and the City Charter to provide electric service, the City can provide power to new developments in the City. This electric utility service goes beyond the generation supply services provided by San Jose Clean Energy ("SJCE") as the default electricity generation provider within the City. City utility service encompasses ownership, operation and maintenance of the electrical interconnection, transformation and distribution facilities as well as customer service and billing. The City electric service would be governed by the Council as the Local Regulatory Authority ("LRA"). The City electric service would not be under the oversight of the California Public Utilities Commission ("CPUC"), though may follow the practice of publicly owned utilities in California that adhere to certain safety-related measures promulgated by the CPUC. Additionally, legacy departing load charges[9] may be guided by CPUC regulations. Thus, the City would have significantly greater control over the operation of the electric service, including the ability to adopt applicable design standards, rules and regulations that would allow for a more advanced microgrid to accommodate increased on-site distributed energy resources and improve electric reliability. The rules and regulations would need to align with the City's broader goals for social equity, resilience, and climate objectives laid out in Climate Smart San José. The City would also develop tariffs and set electric rates based on the cost of service, and offer programs that meet shared environmental objectives.

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[8] City of San Jose Council Resolution 80023, Condition 14, May 25, 2021

[9] A significant component of departing load charges is the power charge indifference adjustment, or PCIA, related to legacy IOU generation resources.

As stated in communications to the Council for the August 29, 2019 energy resilience study session, 25% of Californians receive local public electric utility service.[10] The materials included in the study session memo, based on research compiled by the American Public Power Association ("APPA") [11], demonstrate that local public electric utilities have a proven track record of providing excellent, low-cost service to their customers. Nationwide, APPA finds that local public electric utilities provide more reliable service at costs that average 87% of the cost of investor-owned utility service. Despite the cost being less for local public electric utilities nationally, public power significantly outperforms IOU's when it comes to reliability. Public Power customers experience fewer outages and are left in the dark for shorter periods of time than other customers.

Below is a rate comparison from the energy resilience study session that shows significantly lower rates for four California local public electric utilities:[12]

Table 1: California Utility Rate Comparison

	Residential Rates Compared to IOU	Non-Residential Rates Compared to IOU
Silicon Valley Power (City of Santa Clara	48% Lower	26%-38% Lower
Sacramento Municipal Utility District	33% (Avg.) Lower	31.1%-47.6% Lower
Alameda Municipal Power	14.9%-31.5% Lower	11.3%-18.9% Lower
Los Angeles Department of Water and Power	31% Lower	7-27% Lower

The electric service planned for the DTW Project and other developments is expected to be competitive and more flexible to that of the alternative retail service provided by the IOU -- the benchmark service contemplated in this report, based upon the distribution system design contemplated by the Developer and the City.

The driving force behind many of the benefits of a publicly owned utility is that a city council or local board governs and oversees the design, construction, operation, and rate setting of the electric system, meaning that the local community owns the utility and, therefore, controls the utility's priorities through open meetings and transparent business decisions. Another benefit of City-provided electric service is that local public utilities must provide cost-based rates by law and do not pay taxes or collect a rate of return for investors, which provides cost savings for ratepayers.

[10] August 29, 2019 Energy Resilience Study Session Memorandum dated August 23, 2019
[11] APPA Stats and Facts
[12] Citations included in August 29, 2019 Energy Resilience Study Session Memo, Page 7

Funding

The City would incur startup expenses for several years prior to earning its first revenues from deliveries to electric service customers, and revenues in the early years of operation when loads are low would not be sufficient to fully recover fixed costs and establish appropriate capital reserve funds. The Case Study analysis assumes that the Developer would fully funds these costs. Costs after utility formation and execution of the Business Agreement would be reimbursed to the Developer through future bill credits, if and when revenues from operations exceed going forward costs and repayment of startup costs.

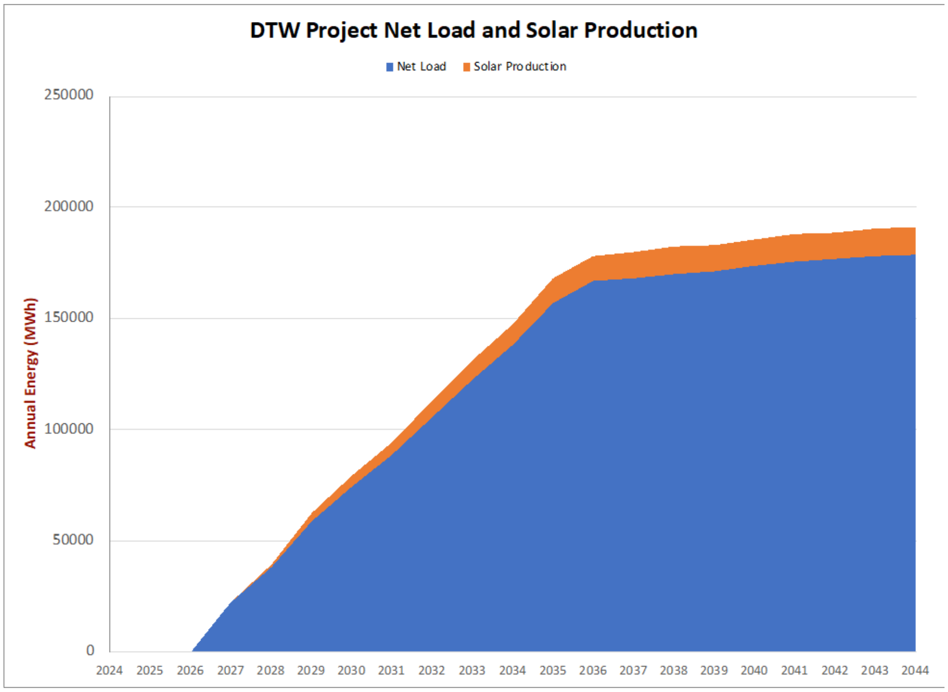
Economic Analysis Summary

Flynn developed a model to produce financial information about the economic feasibility and performance of a City-owned and operated utility serving the DTW project. Overall, the costs of City electric service would be competitive with the benchmark utility service, with expected costs 15-25% below the benchmark rates over the 50-year analysis. Rates would be comparable to the benchmark utility service during the initial 10 years of operations, with savings realized thereafter with growing DTW Project loads. Stress testing with multiple overlapping negative sensitivity values in highly stressed scenarios shows rates could exceed the baseline benchmark rates by 5% to 10% over the analysis period. Mitigation measures are available to deal with this contingency. Conversely, with favorable outcomes simultaneously for several of the most impactful sensitivities, the City rates could be 55% to 70% of the benchmark rates, as further described in the Economic Analysis section.

Project Load/Load Growth

This Case Study uses the Developer's current construction and commissioning schedule. Blocks of load approximately equal to 10% of the full project build-out level are expected to be connected to the City distribution system annually beginning late 2027 through 2035. Smaller increases in load are expected thereafter until the project reaches full buildout in 2044. Figure 2 shows the expected load net of planned onsite customer-owned solar generation.

Figure 2 - DTW Project Net Load and Solar Production (MWh)



The total load would vary based on the pace of the project build out, the energy intensity of the DTW Project occupants, the amount of onsite solar generation and the operation of onsite battery storage. For example, electric vehicle charging capacity is expected to represent approximately 7% of the DTW Project demand and approximately 2% of the gross load. Greater than expected electric vehicle charging load could result in meaningful increases in the annual energy consumption. Higher or lower than expected levels of solar generation could have a similar impact on the amount of energy sold by the City utility. Delays in project build out could result in the need for greater reliance on startup funding and/or for higher initial rates, while acceleration of buildout could reduce the startup funding requirements and result in lower rates.

Service Territory & Facilities

The service territory of the City Utility for the DTW Project is assumed to include all the electrical load, with limited exceptions,[13] within the footprint of the DTW Project. To meet the DTW Project electrical needs, the City and the Developer envision an enhanced distribution system that would be designed to be more reliable, more controllable and more resilient than a traditional electric utility distribution system, consistent with standards adopted by the Council. The planned system would accommodate significant customer owned and operated distributed energy resources (assumed to be all solar) and allow excess renewable generation to be stored for later use or used to serve other DTW Project customers, creating a more carbon free mix. In anticipation of Public Safety Power Shutoffs, storage and Central Utility Plant ("CUP") thermal

[13] Some existing buildings within the DTW Project footprint and some affordable housing may be served by the IOU. Streetlights and traffic signals are assumed to be served by the IOU but could be served by the City.

resources would be charged/pre-cooled and some critical loads would continue to be served during periods in which they otherwise would have experienced an outage with a traditional distribution system. The Business Agreement and subsequent agreements between the City and the Developer would specify how these facilities and resources would be financed, constructed, owned, managed, operated, and maintained.

The configuration, characteristics, and utilization of generation and storage resources would be determined based on multiple goals: carbon mitigation, "islanded" microgrid operation, utility cost optimization, or a combination of the above[11]. While the distribution infrastructure costs would be higher than those for a traditional distribution system, the expected benefits listed above would be significant. The economic analysis included in this document shows that, although this enhanced distribution system would cost more and therefore increase some capital components of the cost of providing service, the expected benefits would offset these impacts, with the ultimate cost of service expected to be lower than benchmark service. In addition, the additional capital costs would make for an electric utility that is more resilient to grid-caused disruptions and would provide a service that maximizes climate change benefits using the available renewable energy and energy storage assets.

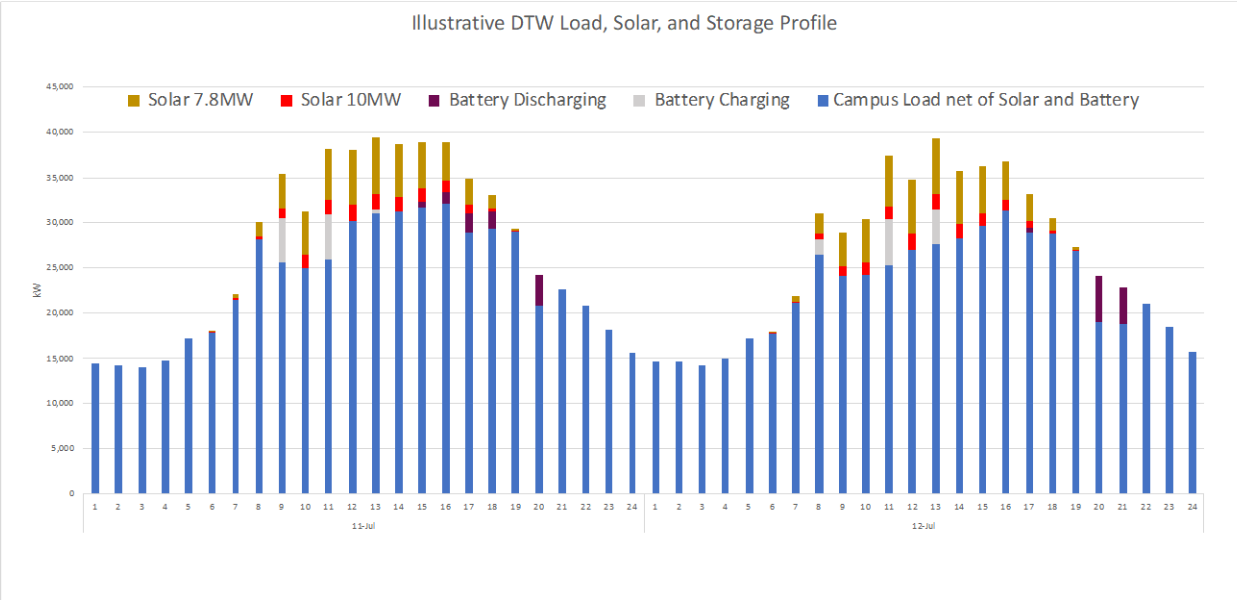
Because the DTW Project is expected to be built in phases, the electrical infrastructure needed to serve each phase would also need to be completed in different stages. The Developer would build a substation in advance of the first DTW Project Phase 1 buildings being occupied to interconnect to the 115 kV transmission system. This substation would have two transformers to reduce the voltage to 12kV distribution voltage ("City Substation").

Portions of the City electric service enhanced distribution system in conjunction with the envisioned customer-owned solar PV and storage resources, would operate in islanded mode during grid related outages. While additional study is needed to determine the amount of load that can be served in islanded mode, the planned distribution system should provide an expanded level of resilience to address future Public Safety Power Shutoffs and other emergency conditions that otherwise would have resulted in interruption of power supply.

Power Supply Plan

The DTW Project is expected to incorporate a significant amount of customer-owned solar PV generation resources, as well as significant battery storage resources. Current plans are for 7.8 MW to 10 MW of onsite solar generation and 7.8 MW/15.6 MWh to 10 MW/20 MWh of storage resources. The greater the amount of onsite solar generation, the lower the amount of net load to be served from off-site resources. While this solar generation would increase the cost per kWh to recover the fixed costs of the project, in conjunction with the onsite storage resources, it would decrease overall costs by reducing the amount of resources that the City utility would need to procure, including reductions in electrical capacity resources or demand-side resources needed to meet applicable reliability requirements ("Resource Adequacy"). Figure 3 depicts a representative hourly summer load, solar and storage profile for the DTW Project.

Figure 3 –DTW Project Hourly Summer Load, Solar and Storage Profile



The DTW Project is expected to be served by carbon-free resources, with a goal to do so on an hourly basis for a minimum of 92% of the hours each year, and the economic model assumes energy procurement costs consistent with supporting these goals. The City utility resource management staff could work with the Developer and other DTW Project customers to develop a remote resource procurement plan as more information becomes available about the timing and composition of the net project loads.

Economic Analysis

For the Case Study, Flynn developed a model to produce financial information about the economic feasibility and performance of a City utility. The model analyzed the costs to serve the DTW Project loads and compared results to benchmark IOU service for multiple scenarios using a discounted cash flow approach. Overall, the cost of City electric service would be competitive, with expected costs 15% to 25% below the benchmark rates over the 50-year analysis. Rates are expected to be comparable to the benchmark utility service during the initial 10 years of operations, with savings realized thereafter with growing DTW Project loads. Stress testing scenarios with multiple overlapping negative sensitivity values in highly stressed scenarios shows rates could exceed the baseline benchmark rates by 5% to 10% over the analysis period, though performance still yields savings even under many of the stressed scenarios, as further described in the Sensitivities and Scenarios section below.

The Case Study model identified the factors, or cost drivers, that would directly affect the cost of service used to determine rates for customers of the City utility. We varied input assumptions for each cost driver depending on the best assumptions that could be made with available data and using our best engineering judgment. The Developer provided their latest estimates of the amount and timing of project load, and the amount of onsite solar generation for the analysis. The timing and ramp up of loads strongly affect the project economics. This suggests a possible mitigation option to defer staffing to align with lower customer requirements in the early years, and to add staffing as the requirements grow over time. With the cost driver data defined and entered in the model, it was used to estimate annual cost per kilowatt-hour of electricity under many scenarios. This information was used to compare the estimated costs of service against the cost of corresponding service from the existing IOU to determine if, and under which scenarios, a City-provided electric service would offer an economic benefit to customers.

Main Cost Drivers

As described above, cost drivers are specific factors that directly affect the estimated cost of service. The most consequential, or key cost drivers identified and used in the financial model are described below:

- **Annual Customer Energy Usage**– The amount of energy consumed annually by end-use customers within the DTW Project, net of planned on-site generation. This variable is important because a large portion of the costs to provide electric service are fixed, so the amount of load over which they are spread can have a significant impact on the average cost of delivering power to the DTW Project. The base case analysis used the latest project build out scenario and associated load forecast provided by the Developer. The analysis assumes that customer loads are first served beginning in 2027, with gradual increases in load until full buildout in 2044.

- **Staffing** – Includes cost of salaries, benefits and other employee compensation for personnel to manage and operate the utility. We assumed that staff positions would include senior leadership, office administration, legal, engineering, and field operations and maintenance. Most of these positions would be represented by existing unions as is the current structure of the City's workforce. See the Implementation Steps, Structural Growth and Operational Development Plan Implementation Steps, and Staffing sections for a more detailed discussion of the staffing plan. A formal Operations & Maintenance Plan will be completed following completion of the project design and formation of the City utility.

- **Departing Load Charges and Market Benchmark Escalation** – Retail customers within areas currently served by the IOU are responsible for certain charges under the Transferred Municipal Departing Load (E-TMDL) or New Municipal Departing Load (E-NMDL) tariff.[14] These charges include a Wildfire Fund charge,[15] a nuclear decommissioning charge, an Energy Cost Recovery Amount, a Competition Transition Charge and, in some cases, a PCIA". It is the Community Energy Department's view that the PCIA should not apply to the new DTW customers[16] because it only applies if the departing load meets a "large municipalization" standard, which does not appear to be the case with the DTW Project. Despite this view, forecast PCIA charges aligning with market benchmark escalation scenarios were included in the base case and sensitivity cases to provide a conservative estimate of the potential project benefits. Some sensitivity scenarios excluded PCIA charges to show the impacts should CED's view be realized.

- **Benchmark Delivery Rates** – For comparison purposes, the analysis uses forecasts of benchmark delivery rates, in conjunction with SJCE default CCA power supply, for each rate class expected to be served within the DTW Project to develop the benchmark rate. While the City electric service rates would be set based on the City's cost of service, the corresponding benchmark retail rates are useful for comparison purposes. Many sensitivity cases were run to identify key variables and their impact on the relative cost of service versus the benchmark rate. Stress testing scenarios also were developed as further described below.

- **Operational Consulting Costs** – In addition to staff field operations personnel, consulting resources would be required along with warehoused replacement parts to support operations. These costs were assumed to be a function of the total City-owned infrastructure installed costs as shown in Table 1 below.

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[14]TMDL is load at a premise that was served by bundled or direct access electricity service from the IOU and, on or after December 20, 1995, is replaced by electricity service from a Publicly-Owned Utility ("POU"). TMDL does not include "new load," as that term is defined in CPUC D.03-07-028. NMDL is electric load that has never been served by the IOU but locates within its service area as it existed on February 1, 2001 and is served by a POU.[15] Wildfire Fund charges apply to all load except load eligible for CARE and Medical Baseline. The analysis has not excluded Wildfire Fund charges for these loads because these charges also would be excluded for IOU delivery service

[15] Wildfire Fund charges apply to all load except load eligible for CARE and Medical Baseline. The analysis has not excluded Wildfire Fund charges for these loads because these charges also would be excluded for IOU delivery service

[16] Departing load customers pay the PCIA charges directly to the IOU, affecting their total cost of power, in addition to City utility bills.

- **City Utility Energy Cost** – The cost to purchase energy to serve the DTW Project load was estimated by the City and applied on a proportional basis dependent on the amount of annual load. Energy delivered to DTW is assumed to be carbon free for a minimum of 92% of hours in the year.

- **Onsite Solar Generation** – The amount of customer-owned solar generation produced and consumed by the DTW Project customers would reduce the net sales over which project costs would need to be recovered.

- **Uncollectibles** – the amount of annual revenues that are assumed to be unrecoverable from individual customers and thus must be recovered from other customers.

- **Resource Adequacy Costs** – The costs of obtaining generation and storage resources to meet the California Independent System Operator's ("CAISO") reliability requirements, likely to be based on the net DTW Project energy and capacity needs.

Base Case Assumptions and Sensitivity Case Assumptions

Base case assumptions represent the most likely estimate of the value for each cost driver using the best information available and engineering judgement. Sensitivity case assumptions represent reasonable upper and lower bounds scenarios, though not necessarily the most extreme scenarios. Table 2 below shows the base case and sensitivity case assumptions for the key cost drivers.

Table 2 – Base Case and Sensitivity Case Assumptions

Parameters	Base Case	Sensitivity Cases	Notes
Load (Annual Energy)	100%	66% & 120%	Applied to gross load net of solar generation per Developer Summer 2021 build out plan updated in July 2022.
Staffing (Labor) Cost	Base	25% lower and 100% higher	Startup staffing costs supported by Developer financing through 2032 in base case, 2036 in the high case, and 2030 in the low case.
Municipal Departing Load Charges	Incl. PCIA	NBC Only	Base case uses CSJ-provided forecast of PCIA charges through 2024, consistent with the benchmark escalation cases. PCIA charges are held constant beyond 2024. Low sensitivity cases include selected non-bypassable charges only. See E-NMDL Tariff
Analysis Period (Years)	50	30 and 10	50-year analysis aligns with expected life of most infrastructure.
Benchmark Rate	SJCE Default	NA	Use SJCE Default product as a proxy for a carbon-free product 92% of annual hours.
Power Mix	Carbon-free for 92% of hours	NA	Expected DTW Project product
Benchmark Other Rate Escalation (%)	2.5%	Double and Half CPUC 2025-2030 escalation[17]	Escalation rate for non-generation component of benchmark rate. CSJ-provided base forecast including current IOU General Rate Case requests through 2024, with CPUC distribution forecast through 2030. The escalation from 2022 through 2027 is 50%. High/Low cases have double/half CPUC escalation through 2030, with escalation at inflation thereafter.
Cost of Debt	5%	NA	Debt interest rate.
Solar (MW) and Storage	7.8 MW/15.6 MWh	7.8 MW/15.6 MWh and 10 MW/20 MWh	Customer-owned solar.
Operational Consulting Costs	2.50%	1.5% and 3.5%	Consulting costs as a function of City utility infrastructure installed cost.
Uncollectibles	1.10%	0.5% and 2.0%	Base reflects typical uncollectible levels. Lower levels could be realized for the DTW Project.
Grid Controller Replacement Period	16 yrs.	12 and 20 yrs.	Microgrid control hardware and software and field switch controllers.
Controllable Switch Replacement Period	30 yrs.	20 and 40 yrs.	Distribution system controllable relays/switches.

[17] Utility Costs and Affordability of the Grid of the Future, May 2021

Analysis Findings

Flynn's analysis found that with base case assumptions, the net present value of the cost for the City to provide utility service to the Development over the 50-year analysis is approximately 75% to 85% of benchmark rates, which equates to City electric rates being approximately 15% 25% lower than the benchmark rates. The projected ratepayer savings between possible City costs and benchmark rates is a weighted average accounting for the present value of all costs associated with operations and maintenance, staffing, resource procurement and all other costs of operating a municipal utility, including a 5% utility revenue payment to the City's General Fund in lieu of taxes and franchise fees. Figure 4 illustrates the comparison between expected City utility costs and benchmark rates on an annual basis. The forecast benchmark rates are shown as a dark red line, with the red striped area around the baseline rates representing the potential range of benchmark rates. The projected City utility rates are shown as a dark blue line, with the blue/gray shaded area representing the potential range in City utility rates. In the early years, City utility rates are expected to be set at levels competitive with the benchmark rates with Developer funding of startup costs, which would be reimbursed if and when DTW Project loads have grown to levels sufficient to support going forward operational costs, funding reserves and repayment of pre-operational startup costs at rates competitive with benchmark service.

Figure 4 – Illustrative City Rate vs. Benchmark Rate

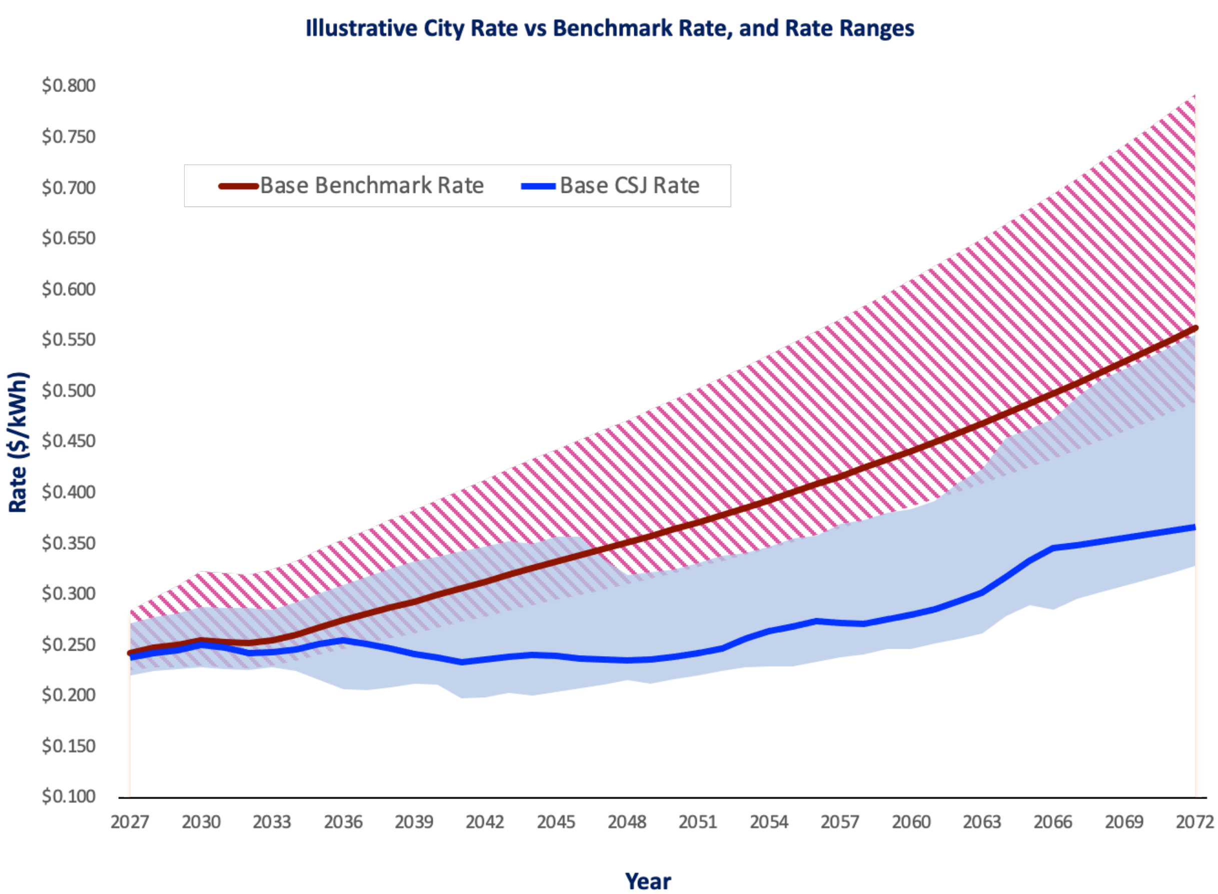

Table 3 shows the results of applying the sensitivity factors to help identify those factors that have the greatest impact on the cost of serving the DTW Project. Benchmark non-generation costs, amount of load, staffing costs and the escalation rates for the market benchmark impacting applicable PCIA charges are the most important sensitivity factors. For example, if benchmark non-generation costs escalate during 2025-2030 at half the CPUC-forecasted rate, savings for City utility service would decrease approximately 9%. Conversely, if benchmark non-generation costs increase at twice the CPUC-forecasted rate (such as could happen if greater than expected hardening of the benchmark distribution system takes place), savings for City utility service would increase 15%. If the actual energy consumed by the customers is only 66% of the base case assumption, the savings for City utility service would decrease approximately 14%. Conversely, should the actual energy consumption by the customers be 120% of the base case scenario, the overall savings would increase 4% percent. If staffing costs are double the expected level savings would decrease approximately 13%, whereas, if staffing costs are 25% lower than expected, savings would increase by a few percent.

The PCIA is also an important factor affecting the savings for City utility service. If the PCIA is applicable to the DTW Project customers, and the market benchmark is low, savings from City utility service decrease approximately 6%. Conversely, if the PCIA applies and the market benchmark is high, savings increase by approximately 4%. Other factors have a less significant impact on overall project costs. This type of analysis allows the City and the Developer to understand which cost drivers and uncertainties are more impactful on the rates to be charged under the City utility service option in comparison to benchmark utility service.

Table 3 – Selected Sensitivity Factors

Selected Sensitivity Matrix							
	Assumptions			Results (City Utility vs. Benchmark (%))			
Parameters	**Base**	**Low**	**High**	**Base**	**Low**	**High**	**Delta**
Benchmark Other Rate Escalation (%)	Base	Low	High	76%	85%	61%	24%
Load Sensitivity (%)	100.0%	66.0%	120.0%	76%	90%	72%	17%
Staffing Cost Contingency (%)	0.0%	-25.0%	100.0%	76%	73%	89%	16%
Market Benchmark Escalation	Base	Low	High	76%	82%	72%	10%
Consulting O&M Variable (%)	2.5%	1.5%	3.5%	76%	74%	79%	5%
Infrastructure Cost Contingency (%)	20.0%	-10.0%	40.0%	76%	74%	78%	5%
CSJ Other Rate Escalation (%)	2.5%	1.7%	3.3%	76%	75%	78%	3%
Energy Cost Escalation Rate (%)	0.00%	-0.24%	1.33%	76%	76%	79%	3%
PCIA Sensitivity	Incl. PCIA	Excl. PCIA	Excl. PCIA	76%	76%	74%	2%
Uncollectibles Factor (%)	1.1%	0.5%	2%	76%	76%	77%	2%
Controller Replace Frequency (Years)	16	20	12	76%	76%	77%	1%
Switch Replace Frequency (Years)	30	40	20	76%	76%	77%	1%
RA Cost Factor (%)	75.0%	50.0%	90.0%	76%	76%	77%	1%
Solar (MW)	7.8	7.8	10.0	76%	76%	77%	1%

Table 4 shows the results of applying the sensitivity factors and combining them into scenarios. Depending on which sensitivities are applied in the model, the cost-of-service savings for City-provided service increases or decreases compared to the base case scenario. Such increases or decreases would have a follow-on impact on the rates that would need to be charged to recover the costs. The scenario analysis shows that if several of the factors with medium impacts on the results have overlapping negative outcomes, the City rates would be approximately equal to the benchmark rates. But if the scenario includes nearly all of the most impactful negative factors, City utility rates would need to be approximately 5% to 10% higher than the benchmark rates to cover the cost-of-service. Conversely, with favorable outcomes for several of the most impactful sensitivities, the City rates could be 55% to 70% of the benchmark rates.

Table 4 – Scenario Analysis Results

Scenario Matrix -- Overlapping Sensitivities										
	Sensitivity Parameters									
Scenario	Load	Staffin g Cost	Infrastructure Cost	Consultin g O&M	PCIA	Market Benchmark	Benchmark Non-Gen Esc.	CSJ Non-Gen Esc.	Energy Cost Esc.	City Utility vs. Benchmar k
High CSJ Costs/Low Benchmark	Base	High	High	Base	Base	Low	Low	High	High	109%
Low CSJ Load/Low Benchmark	Low	Base	High	Base	Base	Low	Low	Base	Base	108%
High Staff, Infrastructure/Low Benchmark Distribution	Base	High	High	Base	Base	Base	Low	Base	Base	100%
Low Load and High CSJ Costs	Low	Base	High	High	Base	Base	Base	High	High	100%
High CSJ Costs	Base	High	High	High	Base	Base	Base	High	High	98%
High CSJ Energy and Distribution/Low Benchmark	Base	Base	Base	Base	Base	Low	Low	High	High	94%
High Staff and Infrastructure Costs	Base	High	High	Base	Base	Base	Base	Base	Base	91%
Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	76%
High CSJ Load and Low Infrastructure and O&M Costs	High	Base	Low	Low	Base	Base	Base	Base	Base	69%
Low CSJ Staff, Infrastructure O&M, and Energy Costs	Base	Low	Low	Low	Base	Base	Base	Base	Low	68%
High CSJ Load/High Benchmark	High	Base	Base	Base	Base	High	Base	Base	Base	68%
High CSJ Energy Cost/High Market Benchmark	Base	Base	Base	Base	Base	High	High	Base	High	60%
Exclude PCIA/High Benchmark Distribution	Base	Base	Base	Base	Low	Base	High	Base	Base	60%
Low CSJ Staff Costs/High Benchmark	Base	Low	Base	Base	Base	High	High	Base	Base	55%

While Flynn has been careful to use reasonable assumptions about the costs to build, own and operate the distribution utility, if the sensitivity assumptions prove to be wrong in more areas than shown above without corresponding favorable outcomes in other areas, the costs of City utility service could be higher than the benchmark rates. That being said, the other benefits of the project, including enhanced reliability, increased resiliency and greater use of renewable resources, among others, that are not necessarily directly reflected in a cost-of-service analysis, still provide additional value. Further investigation and stress testing of the key sensitivity variables would be conducted during the next phase in the investigation of City utility service. See the Key Risks and Mitigation Strategies section below for discussion of mitigation measures.

Key Risks and Mitigation Strategies

The sensitivity analysis and the scenario analysis described in the Economic Analysis section identified the most significant risk factors. This section further describes those risks and discusses potential mitigating factors and mitigation strategies.

Load Level Risks

Not achieving the planned amount of net load and delays in timing of achieving full buildout are potentially significant risks for the City utility. Each would result in lower-than-expected revenues, presenting challenges for keeping the City utility rates competitive. To mitigate these risks, the City and the Developer could work to resolve some of the load uncertainty before making major financial commitments. The City could also phase staffing to align with updated load projections.

The load uncertainty also creates risks related to power supply procurement since commitments for power supply could burden the utility if there are delays in the timing of load connections or loads are lower than expected. These risks can be mitigated by deferring long-term commitments until buildout timing is more certain. The current market for new renewable and storage resources for the near term (i.e., 2023 – 2026) is extremely competitive. Given that initial customer loads are not expected until the second half of 2027, ramping up approximately 4 MW per year over 5 years before reaching approximately 39 MW in 2044, there could be some benefits from deferring long-term resource commitments until more information is available about the timing and amount of the customer load connections.

Staffing Cost Risks

Because the City utility initially would be a relatively small utility, and because some of the costs of operating a utility are fixed and not dependent on the size of the distribution system, small changes in the level of staffing or unplanned equipment replacement can have a large impact. This could result in higher-than-expected rates. This risk can be mitigated by phasing staffing to align with changes in load projections and by relying on design-builder warranties and performance assurance for several years to address unplanned or emergency equipment replacement.

PCIA Risks

PCIA charges initially were excluded from the Case Study analysis based on the IOU's indication that they would not apply, but the IOU now has provided conflicting representations about the applicability of the PCIA to the DTW Project loads. To provide a conservative estimate of the project benefits, the PCIA charges were included in the analysis base case and in most stress testing scenarios. PCIA charges were excluded in some sensitivity cases and some low-cost scenarios to show the impacts if CED's view that these charges should not apply is realized.

Customer Satisfaction Risks

Higher rates relative to customers' perceived benchmark could result in customer dissatisfaction with City-provided service. This risk could be mitigated by working to control costs and implementing the risk strategies discussed above, including working to resolve some of the load uncertainty before making major financial commitments

Operational Cost Risks

The City substation and distribution facilities are important high-cost assets that would need to be operated, maintained, and eventually replaced. These costs would be at least partially controllable, so it would be important to implement risk management measures to reduce the financial exposure. These measures would include allocating industry standard annual budgets for O&M, establishing funds annually for equipment replacement, and ensuring procurement of equipment that comes with industry standard warranty and service level guarantees. This financial analysis includes the costs associated with implementing each of these risk management measures. Once the design of the distribution system has been completed, the City would develop a specific O&M plan during the construction phase and prior to the cost-of-service study. In collaboration with the Developer, the City could also explore lower cost alternatives to complex microgrid controls for portions of the distribution system (e.g., use SCADA as an alternative for isolating some transformers from the distribution system during islanded mode)

Key risks and potential mitigation measures to address the financial risks shown above in Table 3 and Table 4 are summarized in Table 5.

Table 5: Key risks and potential mitigation measures

Key Risk Factor	Potential Mitigation Strategies
Low load level and delayed timing	• Defer staffing and power procurement decisions to align commitments with loads. • Obtain Developer funding of startup costs and link reimbursement to ability to pay/sufficient load.
Higher Staff Costs	• Control costs and use higher end assumptions in financial analyses.
Applicability of PCIA Charges	• Oppose efforts by the IOU to impose PCIA charges for the DTW Project to reduce the administrative burden of tracking PCIA charges and the potential financial risks associated with such charges.
Lower than expected benchmark non-generation rates	• City and the Developer could work to resolve some of the load uncertainty before making major financial commitments. • The City could also phase staffing to align with updated load projections.
Distribution system O&M and replacement cost	• Explore lower cost alternatives to complex microgrid controls for portions of the distribution system (e.g., use SCADA and advanced metering control features as alternative for removing some transformers from grid during islanded mode). • Establish replacement reserve fund to smooth replacement cost impacts.
Microgrid controller replacement frequency	• The risk of having to replace the microgrid controllers frequently potentially can be mitigated by obtaining vendor warranties or by specifying more traditional distribution control systems.

Implementation Steps

Implementation Roadmap

To prepare to provide City utility service for new developments, the Council could form the City utility by adopting an ordinance, approve municipal code revisions and approve the Business Agreement. Design Standards would be approved by the Council in advance of Developer construction of the electric infrastructure. The City utility would develop rules and regulations for Council approval governing how electric service would be provided to the City's customers. Council then would approve the Interconnection Agreement for transmission service, receive the cost-of-service study and approve customer rates prior to the City utility providing retail service.

The cost-of-service study would be conducted by a third party with recognized expertise in electric utility accounting using standard utility practice. Cost categories would utilize the Federal Energy Regulatory Commission ("FERC") uniform system of accounts ("USOA") and costs would be benchmarked against the periodically published American Public Power Association Report *Financial and Operating Ratios of Public Power Utilities.*[18]

The City and Developer would also negotiate the terms of the facility transfer as part of the Business Agreement to address the transfer of Developer constructed assets to the City utility.[19]

[18] Financial and Operating Ratios of Public Power Utilities, APPA

[19] The term "Business Agreement" is provisional and provided for convenience and reference purposes only. The use of this term in this Case Study should not preclude the use of different terms or affect the interpretation of any potential future agreement(s) between developers and the City. Timing for the Business Agreement is subject to additional revisions, including potential execution after the formation of the utility. Multiple agreements could be presented to Council separately or as a single package that would be adopted in one or several meetings.

The City would need to undertake some actions over a multi-year period to provide electric service to new developments. Assuming a service date of 2027 for the Case Study, those actions include:[20]

- Council acceptance of Case Study (Summer 2022)
- Council ordinance forming the City Utility (Fall 2022/Winter 2023)
    - Municipal code revisions
    - Business Agreement[21]
        - Defines startup costs and facility transfer
- Council approval of Design Standards (2023)
- Council approval of Interconnection Agreement (2023/24)
- Council approval of Rules & Regulations (2023/24)
- Cost of service study (2026)
- Council approval of Rates/Tariffs (2027)

Formation Steps

The City Attorney's Office engaged outside counsel with extensive knowledge and experience in the energy and utility industry to evaluate the legal and regulatory feasibility of the City providing electric distribution service to new developments in the City. They confirmed that the City has a legal and regulatory path to provide electric service to the DTW Project by exercising its authorities under State Law, the City's Charter and Municipal Code to form a municipal utility department within the City. The City could provide electric service to new developments by building new electric distribution infrastructure without requiring the purchase of the incumbent IOU's existing infrastructure.

Agreements and Electric Rules & Regulations

Subject to Council approval, the City and Developer would need to negotiate agreement(s) to allocate responsibility for the Developer to fund the utility startup costs, transfer the Developer funded and constructed electric infrastructure to the City to serve the DTW Project, and fully fund any costs ultimately allocated to the City for the required interconnection facilities and applicable network upgrades (if any) to be owned by the IOU. This agreement would include terms and conditions for reimbursement to Developer of post utility formation non-capital costs if and when utility revenues support bill credits at rates comparable to IOU benchmark service. Additional agreements could be needed during the formation and implementation of the electric utility service to the DTW Project.

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[20] Utility formation steps would be taken only once. The dates shown are tentative and subject to change depending on the specific circumstances of the development.

[21] The term "Business Agreement" is provisional and provided for convenience and reference purposes only. The use of this term in this Case Study should not preclude the use of different terms or affect the interpretation of any potential future agreement(s) between developers and the City. Timing for the Business Agreement is subject to additional revisions, including potential execution after the formation of the utility. Multiple agreements could be presented to Council separately or as a single package that would be adopted in one or several meetings.

Other agreements with the IOU, the CAISO and third-party power suppliers ultimately would be necessary and are described below.

Business Agreement(s)

The City and Developer would negotiate the Business Agreement to address startup cost funding facility transfer, and reimbursement of post-formation costs The Business Agreement would address, but not be limited to, the following:

- Developer's responsibility for funding City staffing and outside services costs after formation of the City utility and any net costs not covered by operating revenues in the early years after starting electric deliveries to City customers. The startup costs would be reimbursed if and when net revenues from operations are sufficient to support going forward costs and reimbursement of the startup costs.
- City's responsibility for repayment of the startup costs, which would be reimbursed if and when net revenues from operations are sufficient to support going forward costs, reserve funding, and the reimbursement of the startup costs.
- Developer responsibility for constructing the infrastructure required to serve the DTW Project, and to transfer those facilities to the City to own and operate. Once transferred from the Developer, the City-owned infrastructure would include the City Substation and the distribution/microgrid facilities.
- Developer responsibility for funding any costs ultimately allocated to the City for IOU-owned infrastructure required to serve the DTW Project. The IOU-owned infrastructure required to serve the DTW Project is anticipated to include a switching station, potential upgrades to the IOU's Station A, and, potentially, upgrades to other network transmission facilities.
- Developer responsibility to conform with City-approved design standards; City-approved electric rules and regulations and associated performance requirements; asset commissioning and testing prior to transfer of title; easements; and any other applicable laws, regulations, and agreements.
- Developer responsibility to conform with: 1) City-approved design standards and the Conditions of Approval in the Vesting Tentative Map; and 2) City-approved electric rules and regulations and associated performance requirements.
- Developer and City responsibilities related to any other applicable laws, regulations, and agreements.

Electric Rules and Regulations

The City would need to develop and adopt electric rules and regulations and contract terms that address: i.) DTW Project Developer Business Agreement for providing and/or funding the cost of the City Substation and distribution facilities, ii.) DTW Project Developer Business Agreement for funding IOU-required network interconnection facilities and/or network upgrades, and iii.) the operational protocols to be used in coordinating the City's operation of the distribution facilities and the maintenance, operation and dispatch of the Developer/tenant-owned generation and storage resources. These rules and regulations would be developed after the formation of the City utility.

Microgrid Operating Modes

The rules and regulations can also be the vehicle for addressing several operating modes including but not limited to: i.) "blue sky" operations, ii.)"grey sky" operations and iii.) "islanded" operations.

Blue sky operations encompass normal operating conditions in which grid level power supply is available to the utility, with solar generation and storage resources available to meet selected carbon/cost/resilience objectives. In Blue Sky mode, the real time cost and carbon content of external resources would be passed on to customers based on their dispatch of loads and resources. The City utility would allow netting of all loads under common ownership regardless of whether they cross public rights of way. This added flexibility of City delivery service versus IOU delivery service is an important benefit of City service.

Grey sky operations would be invoked during periods in which grid level power is available, but reserve margins are projected to be insufficient. In this mode, the City utility would assume limited dispatch authority over, for example, a portion of the battery storage assets to ensure that it complies with CAISO emergency instructions during these periods of grid stress. In these circumstances, City utility's microgrid controls could initiate load shedding across the DTW Project to reduce stress on the grid as needed. DTW Project storage resource charging and discharging would be altered to reduce demand as needed to support critical operations, and potentially to increase storage charging in anticipation of islanded operations.

Islanded operations would occur if and when grid level power becomes unavailable. City utility's microgrid controls would initiate load shedding across all DTW Project assets to optimize storage run-time. The storage charging and discharging profiles would be altered to meet the reduced demand without the benefit of a grid connection.

Transmission Interconnection Agreement

Wholesale transmission service is available to the City pursuant to the IOU's Transmission Owner's Tariff ("TO Tariff"),[22] and is available to Eligible Customers as defined in Section 3.20 therein, which generally requires that such customer be an entity providing distribution services to third parties and not solely be the end- user. The TO Tariff is a FERC jurisdictional tariff. The City is in the process of obtaining this transmission level interconnection service.

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[22] IOU Transmission Owner Tariff

CAISO Agreements

To enable City utility participation in CAISO markets, the City would need to execute or put in place various agreements/arrangements.

Scheduling Coordinator/Scheduling Coordinator Agreement

The City became a CAISO certified scheduling coordinator ("SC") in 2021 to facilitate SJCE CCA participation in CAISO markets. This step also would allow the City utility to participate in the CAISO markets. Scheduling coordinators bid or self-schedule resources and handle the CAISO settlements process. The City would be able to create a separate Scheduling Coordinator Identification number for the DTW Project to compartmentalize the costs for serving the City utility load and the SJCE CCA load.

Meter Service Agreement

Section 10 of the CAISO Tariff requires the CAISO to establish meter service agreements with CAISO Metered Entities for the collection and transfer of Meter Data and requires each CAISO Metered Entity to certify its revenue quality meters and to make Meter Data available to the CAISO. Alternatively, Scheduling Coordinator Metered Entities must have an agreement with a Scheduling Coordinator responsible for providing Settlement Quality Meter Data and must adhere to the requirements and standards for Metering Facilities set forth in Section 10.3 of the CAISO tariff.

Congestion Revenue Rights Holder Agreement

The City would have the opportunity to be allocated Congestion Revenue Rights ("CRRs") to partially offset congestion costs between its resources and its load settlement point. The City already has qualified for and executed the required agreement for SJCE CRR activities, and the City would need to coordinate with CAISO to participate in the CRR allocation process on behalf of the City utility loads, including the DTW Project load.

Utility Distribution Company Operating Agreement[23]

The City would be a Utility Distribution Company ("UDC"), which is defined as an entity that owns a distribution system for the delivery of energy to and from the CAISO Balancing Authority, provides regulated retail electric service to eligible customers, and provides regulated procurement service to those end-user customers who are not yet eligible for direct access or who choose not to arrange services through another retailer. The UDC Operating Agreement establishes the rights and obligations of the UDC and the CAISO with respect to the UDC's Interconnection with the CAISO Controlled Grid and the UDC's cooperation and coordination with the CAISO to aid the reliability and the Operational Control of the CAISO Controlled Grid and the UDC's Distribution System.

[23] Because the City would not own transmission facilities, it would not need to entertain the possibility of becoming a CAISO Participating Transmission Owner.

Structural Growth and Operational Development Plan

To implement the City utility, the City would need to expand operations to support owning and operating electrical distribution infrastructure. Staff could be added to a new Distribution Division of the Community Energy Department or to another Department such as Public Works. Further analysis would be needed to determine the precise organizational structure of the new Division and how it would best fit into the existing City structure. The new operating division would be responsible for coordinating review and approval of the design, construction, commissioning, and ongoing operations and maintenance of the distribution system. The distribution system would include all equipment between the Point of Interconnection ("POI") with the IOU's transmission system to the Point of Common Coupling ("PCC") with each retail customer.

In addition to the electric rules and regulations, the City utility staff in collaboration with the Developer would need to develop a set of System Operational Diagrams and System Operating Procedures (collectively "Operational Documents") consistent with the design standards. These Operational Documents would be used by the Developer in soliciting design, engineering, and construction services for the microgrid. They would also be used to commission and operate the microgrid along with detailed design drawings and specifications.

Staffing

The Distribution Division would focus on operating and maintaining the distribution system. Energy supply for the development would be provided via a shared services agreement with the Community Energy Department resource management group. These services could include power supply during the transition to the stable operations phase, negotiation of long-term procurement resources, SC services, and optimization of Developer owned on-site generation and storage assets via price signals and, by agreement with the Developer, via direct control of dispatch.

The planned staffing needed for the new City utility service would grow over time. In the first phase (now through formation of the City utility), support from additions to existing staff levels and consultants funded by the Developer would be required for the formation of the utility and negotiating other various supporting agreements described in the Key Agreements Section. Planning for DTW Project loads would require preparation of Operational Documents, (including a comprehensive operations and maintenance plan) development of design standards and electric rules and regulations, contracting for engineering and design efforts, preparation of procurement packages for major equipment and preparation of construction plans and specifications. Additional personnel would be required for these efforts as described below.

It is expected that the minimum amount of management, technical, and administrative staff, along with legal support would be used to support the detailed design, construction, commissioning and initial operation of the distribution system. The minimum number of employees needed to operate and maintain the distribution system is expected to be approximately 13 Full Time Equivalent ("FTE") employees. These staffing levels might be expanded up to approximately 26 FTE as the distribution system expands and as load levels increase Following utility formation and completion of the distribution system design, a formal Operations & Maintenance Plan will be developed including budgeted staffing levels and operating expenses. In addition to these staff, the City utility is expected to obtain power procurement support services from the Community Energy Department and legal and administrative support services from other City departments.

Senior management and legal support staff would be needed to negotiate required agreements, to supervise the development of the design standards, and to develop the rules and regulations. After the formation of the City utility, engineering staff would be added to provide oversight for the design and construction of the distribution system by the Developer.

Staff Facilities

Although not yet determined, it is likely that management, engineering, and administrative staff would occupy spaces in or adjacent to the Community Energy facilities at City Hall. New facilities would need to be constructed for field staff, potentially located near the customer substation. Facilities for field staff should include a ready room, shop and warehouse space, and shower and bathrooms. It is also likely that these facilities would have an operations control room with a small backup control room and offices for the engineering staff. Also likely is the need for a computer room for SCADA, microgrid controls, and communications equipment with "critical infrastructure" limited access.

Equipment

Maintenance equipment and spare parts for the distribution system and the City Substation is expected to be recommended by vendors supplying the equipment. The City would need to acquire the maintenance equipment and adopt an appropriate maintenance plan consistent with warranty requirements.

General Support

The Distribution Division is expected to use the City's services whenever available. This would include purchasing, billing, collections, treasury from the Finance Department, as well as central garage and facility services for vehicles, rolling equipment, building mechanicals and janitorial support. The costs for such services were incorporated into the Case Study model via the application of an overhead factor to the staffing costs.

Distribution System Design Standards

Distribution system design standards should be based on Operating Documents, procurement specifications, and construction specifications as well as "Best Utility Practices" of surrounding utilities. The design standards would need to conform with state and federal standards. The City should consider using publicly available standards from leading utilities as part of its standards development process, following engineering studies and Council approval.

Transmission & Distribution Construction

This Case Study assumes that the Developer would fund any costs allocated to the City for the construction of the IOU-owned interconnection facilities, any required upgrades to the IOU's Substation A, and/or the development of a new substation to be owned by the City that would be dedicated to serving the project area, and any required transmission network upgrades, to the extent such costs are to be allocated to the City by the FERC. The Developer would also be responsible for funding and completing the construction of the distribution system. The Business Agreement would address the transfer of these electric infrastructure facilities and include terms and conditions for the transfer of the substation and distribution system to the City at no cost to the City. The Developer would construct the substation and the distribution system per a detailed plan to be incorporated in the facility transfer section of the Business Agreement.

The IOU-owned interconnection facilities are assumed to be constructed by the IOU in parallel with the Developer construction of the distribution facilities, along with the IOU undergrounding of the 115 kV transmission facilities, and the construction of required Network Upgrades, if any, by the IOU.

Funding/Financing

Because the first City utility customers would not be expected to take electric service until 2027, the City utility would need to obtain startup funding to cover staffing and consulting costs to negotiate required agreements, pursue the interconnection agreement with the IOU, develop distribution system design standards, monitor the design and construction of the electrical infrastructure, procure power supply resources, capitalize certain reserve fund accounts and develop proposed rates for Council approval. The Case Study analysis assumes Developer funding of startup costs. The costs incurred after formation of the City utility and execution of the Business Agreement would be reimbursed if and when revenues from operations are sufficient to support going forward costs and repayment of the startup costs.

The infrastructure needed to serve the DTW Project, including the distribution system, City Substation, IOU interconnection facilities and, if applicable, IOU transmission network upgrades would be funded by the Developer.

The development and implementation of a City electric utility has three distinct phases: investigation phase, startup phase, and stable operations phase. Each phase has different funding requirements.

To date, the Developer has been funding the staff and outside consultant time required for the investigation phase. This funding by the Developer is completely at risk and the City has no obligation to reimburse the Developer whether or not the City moves forward with the City utility option. The investigation phase is expected to continue until the City and the Developer have both agreed to proceed with the City utility option and have executed the Business Agreement.

The startup phase would commence following Council approval of the formation of the City utility and execution of the Business Agreement and would continue until the City utility revenues are expected to reliably exceed the annual operating costs of the utility. The initial startup phase funding requirements are expected to initially be relatively modest but would increase significantly once procurement of capital equipment and power supply resources is needed, and staffing levels increase in advance of City utility operations commencing. Because the City utility would have no revenues prior to commencing deliveries to its customers, and because the early year operating costs would be expected to exceed early year revenues, funding must be committed prior to the startup phase. Startup phase funding is assumed to be provided by the Developer and would be reimbursed if and when operating revenues are sufficient to cover operating costs plus the agreed startup phase cost reimbursement.

The City utility is expected to enter the stable operations phase several years after the electric utility infrastructure has been installed and electricity deliveries to end-use customers commence. The transition from the startup phase to the stable operations phase would be strongly affected by the rapidity with which the customer loads grow, and by the amount of any required repayments of startup costs. Once the utility has reached the stable operations phase, it is expected to be self-sustaining via revenues from customer rates, with cashflow needs potentially augmented with outside funding sources, such as from the sale of revenue bonds.

Revenue Requirements

During the startup phase prior to delivering energy to customers, the City utility's annual expenses are expected to grow from approximately $1 million in 2023 to $3.2 million in 2026. Because the City utility would not have customer revenues until 2027, the analysis assumed these costs would be funded by the Developer and would be reimbursed after the City utility has sufficient revenues after entering the stable operations phase, projected to begin between 2030 and 2036. This approach is recommended because it minimizes risk for the City by ensuring the City only reimburses these startup costs, expected to be approximately $25 million, following successful deployment of the electric utility infrastructure by the Developer, transfer of the assets to the City utility, and receipt of sufficient customer revenues to support ongoing operations and repayment of the startup funds.

During the transition from the startup phase into the stable operations phase starting 2027 and lasting through 2030 or 2036, the City utility costs would be expected to increase as additional utility staff are hired and as power is supplied to the DTW Project customers. The stable operations phase would align with growth of customer revenues to cover ongoing operating costs and reimbursement of Developer-funded startup costs. The annual revenue requirements between 2027 and 2032 would be expected to range from $12 million to $25 million. To mitigate risk during the transition, we have assumed $1 million working capital and $5 million of major equipment replacement reserves would be provided by the Developer as part of the Developer-funded startup costs in 2026 and 2027, respectively. The analysis assumes these funds would accrue interest at 5% per annum and would be repaid over 10 years if and when revenues are sufficient to cover costs, starting between 2031 and 2037. In the base case, the total reimbursable developer funding would be approximately $25 million. The actual amount and the timing for reimbursement would vary based on actual revenues and expenses. Working capital is assumed to be funded at 25% of the subsequent year's projected costs and replacement reserves are assumed to be funded at approximately 1.8% of the installed cost of the substation and distribution infrastructure. During the subsequent 10 years, annual revenue requirements, including reimbursement of Developer-funded startup costs, vary in the base case between $32 million and $44 million.

City Utility Rates Process

The City would need to adopt electric rates to cover the cost of service. The rates would be designed to recover the costs for providing electric service to the DTW Project. The initial Cost of Service Study to support the rate development process would need to be completed after more information is known about expected City utility costs and about the characteristics of each class of customer to be served by the utility. The City would need to adopt rules of service and, periodically adopt cost-based rates for each customer class compliant with State law.

Most utilities have retail tariffs or rules governing service for residential, small commercial, large commercial and industrial customers. The latter two can take service at primary voltage if they meet certain load size requirements. The DTW Project is expected to have a large amount of load concentrated at the CUP, adjacent to the City Substation. In addition to this customer, there would be a mix of commercial, residential and electric vehicle charging customers throughout the DTW Project. In compliance with California law, the City utility would need to develop a Net Energy Metering ("NEM") tariff at least for onsite generation below 5% of DTW Project demand. Beyond this requirement, the City utility would develop rate structures aligned with sending market price signals to minimize total customer peak demand and kWh consumption, to minimize the costs to serve the DTW Project. Council would need to consider and approve the electric rates and tariffs prior to customer deliveries.

Conclusion

This Case Study describes the economic, organizational and operational requirements for the City to establish and provide electric utility service to the DTW Project using a Developer-constructed enhanced distribution system that would be more reliable, more controllable and more resilient than a traditional electric utility distribution system. The Case Study is premised on the City adopting applicable design standards and electric service rules and regulations that would allow for an advanced microgrid to accommodate more on-site distributed energy resources and improve electric reliability and resiliency. These on-site solar generation and storage resources would be used to meet selected carbon/cost/resilience objectives, with the real-time benefits and cost and carbon content of external resources passed on to customers based on their dispatch of loads and resources. The City utility would allow netting of all loads under common ownership regardless of whether they cross public rights of way. This added flexibility of City delivery service versus IOU delivery service is an important benefit of City service.

The Case Study for the Downtown West Project demonstrates the opportunity for the City to partner with developers to achieve the shared objectives of providing reliable, resilient, carbon free power to customers within a new development at a competitive cost compared to traditional IOU service. While there could be scenarios with multiple, overlapping factors resulting in costs that could exceed benchmark service costs, these scenarios are unlikely and there are mitigation measures the City and the Developer could take to address the potential negative outcomes. There also are scenarios that would provide significant additional savings above the base case.

The approach described herein could be a model for the City to provide similar service to the DTW Project and other new developments within the City. By taking the step to form a City utility to provide electric service to new developments, the City would position itself to be able to realize the benefits exemplified in this Case Study of the DTW Project, significantly contribute to achievement of Climate Smart San Jose goals, increase onsite distributed energy resources and improve resiliency within new developments.