DRAFT

CleanPowerSF Integrated Resource Plan

CO-AUTHORED BY

San Francisco Public Utilities Commission

IN COLLABORATION WITH BLACK & VEATCH

JULY 2018

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1.0 Executive Summary

1.1 CleanPowerSF Background and Growth Trajectory

CleanPowerSF provides energy for residents and businesses within the City and County of San Francisco in a way that furthers its goals of affordability, reliability, clean energy growth and local investment, and long-term stability. A community choice aggregation (CCA) program housed within the San Francisco Public Utilites Commisison (SFPUC), CleanPowerSF started serving customers with an average demand of approximately 60 megawatts (MW) in 2016. After a growth planning process and regular updates on program progress to its Commission, CleanPowerSF plans to expand service to its remaining eligible customers in 2018 and 2019, and anticipates requiring energy supply to serve more than 400 megawatts (MW) average demand. The growth and maturation of CleanPowerSF necessitates significant new procurement of energy supply, to build an energy supply portfolio that serves CleanPowerSF's goals and minimizes risk.

1.2 Study Design Objectives and Methodology

This Integrated Resource Plan (IRP) analysis is designed to help CleanPowerSF make informed procurement decisions as the full subscription Community Choice Aggregation (CCA) is rolled out and to identify resources and actions required to meet state mandates and City of San Francisco (City) greenhouse gas (GHG) goals by 2030 and beyond. The analysis performed as part of this IRP has both near- and long-term objectives. In the near term, the analysis is meant to inform the procurement decisions that CleanPowerSF will be making as the full subscription to the CCA is rolled out in the next 3 years. Long term, the analysis will be used to forecast the resources and actions necessary to meet state and City goals for renewable and GHG free energy by 2030 and beyond.

To perform this analysis, CleanPowerSF's contractor, Black & Veatch, created a Net Short Model to determine CleanPowerSF's annual net short/long position, as well as a Procurement Impact Model that determines the hourly balance between supply and demand for the 2018-2030 analysis period. All state and City requirements are met at appropriate time durations (e.g., Renewable Portfolio Standard [RPS] requirements, resource adequacy, and GHG targets). The incremental cost was modeled for each case to compare them to each other; sensitivities were tested on specific variables. The cases and sensitivities performed were as follows:

- **Case 1:** Balanced Procurement (50 percent wind and 50 percent solar photovoltaic [PV] for incremental procurement).
- **Case 2:** High Wind Scenario (77 percent wind and 23 percent solar PV).
- **Case 3:** High Solar Scenario (77 percent solar and 23 percent wind).
- **Case 4:** Maximize Local Resources (33.7 megawatts [MW] of wind and 33.7 MW of solar in Case 1 were replaced with Bay Area resources).
- **Case 5:** Maximize Local Resources – High Wind Scenario (Combination of 67 MW of local resources from Case 4 and high wind to solar ratio from Case 2)
- **Sensitivity 1:** High and Low Wholesale Energy Market Prices.
- **Sensitivity 2:** Investment Tax Credit (ITC) Extension (30 percent through 2030).
- **Sensitivity 3:** Higher Local Wind Costs.

CleanPowerSF and Black & Veatch worked collaboratively to develop the IRP inputs on the basis of existing resource contracts, wind and solar PV resources identified in the SFPUC publicly-owned utility (POU) IRP, and state storage requirements. Generic California-based resources were procured in the analysis model to simultaneously meet the state RPS mandate, as well as the City GHG-free goals. Input assumptions that would be the same for all cases were ignored to allow a clear comparison between cases.

1.3 Findings

The analysis determined the amounts of projected CleanPowerSF supply required to meet the state RPS and additional City renewable requirements, SuperGreen customer signups, GHG-free, and resulting conventional purchases (shown in Figure 1-1). This amount of procurement is assumed to be needed in all cases and sensitivities and, thus, does not change with the generation portfolio used to meet the requirement.

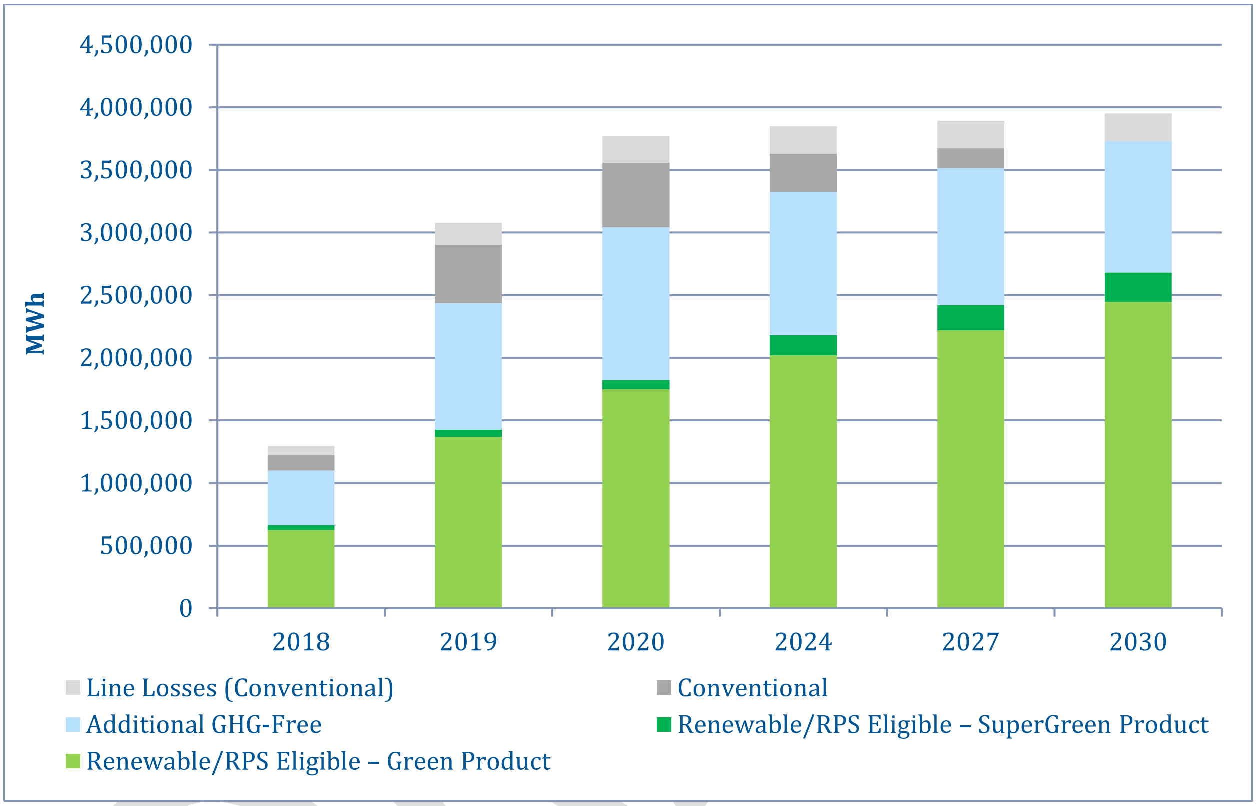

Figure 1-1 Projected CleanPowerSF Supply Types (MWh)

After the analysis was complete, the cases were compared as shown in Table 1-1. The incremental cost to CleanPowerSF is lowest for Case 2, where most of the renewable energy procured is wind. This is because of projected low cost Power Purchase Agreements (PPAs), a resource portfolio best meeting the expected load profile of CleanPowerSF, and expected market power expenditures occurring during low cost periods relative to other portfolios.

Table 1-1 Comparison of Results for Study Period Duration (2018 to 2030)

	Incremental Annual NPV Cost ($MM)	Total Annual Energy Purchases ($MM)	Total Annual Energy Sales ($MM)
Case 1: Balanced Procurement	$1,169	$505	$18
Case 2: High Wind Scenario	$1,119	$428	$22
Case 3: High Solar Scenario	$1,227	$613	$29
Case 4: Maximize Local Scenario	$1,179	$503	$17
Case 5: High Wind and Maximize Local Scenario	$1,131	$429	$21

To graphically demonstrate the advantages of the High Wind case, Figure 1-2 shows the projected energy balance on all hours for a specific date, 1 August 2021, for Case 2 and Case 3. The energy balance is the result after the existing resources are accounted for, and the new, California-based wind and solar purchases are taken into account; the remaining energy needed to meet the hourly load must be purchased from the market. In Case 2 (high wind, blue line), market purchases are highest during the middle of the day when the market pricing (green line) is projected to be low. By comparison, a Case 3 (high solar, purple line) is actually selling power to the market during the middle of the day, when pricing is low, and buying power during other, more expensive times of the day. In other words, in the High Wind case (Case 2), power is being purchased when the market price is low and being sold when the market price is high. Thus, it makes sense that the total incremental annual cost of the High Wind case has the lowest net present value (NPV) cost compared to the High Solar case. A similar trend was found for many of the other months of the year, although it was less pronounced in the winter.

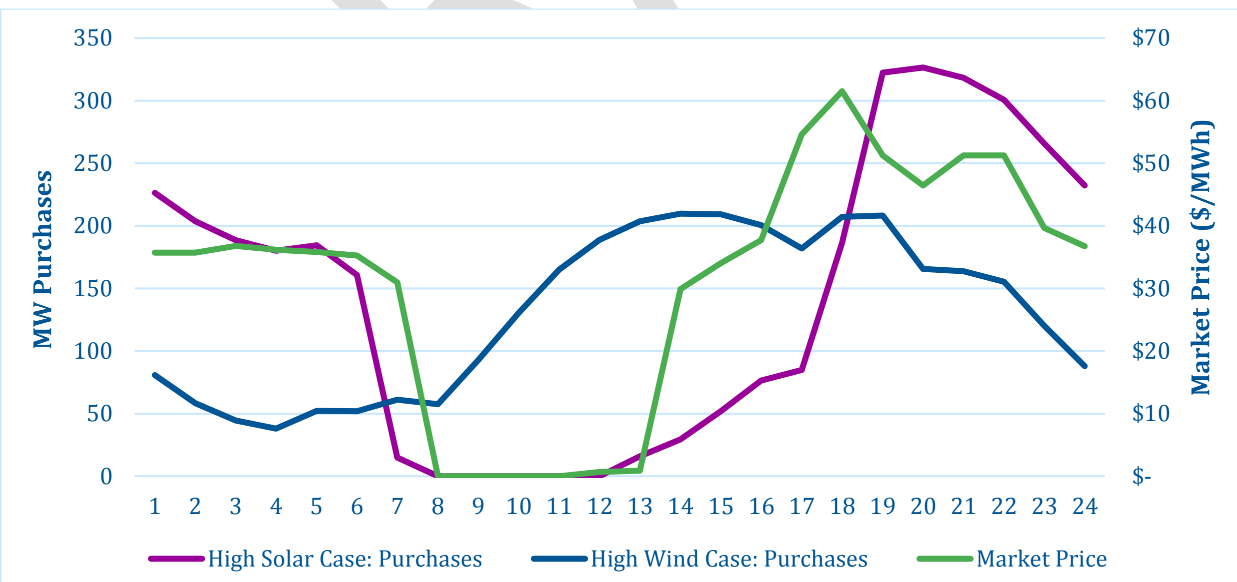

Figure 1-2 First of August 2021 Energy Balance, Case 2 and Case 3

The sensitivity analysis found the following:

- High and low market prices do not impact the relative advantages of the High Wind case (it is still most incrementally cost-effective, as shown in Table 1-2).
- Extending the federal ITC beyond its current expiration date, which reduces the cost of solar energy, has a small impact on the results (NPV costs change between 1 to 3 percent depending on the Case, as shown in Table 1-3).
- An increase in the cost of local wind resources by 10 percent yields a 0.3 percent difference in total incremental cost (this is due to the relative contribution of local wind to the the total incremental costs of the portfolios; results are shown in Table 1-4).

Table 1-2 Low and High Market Price Incremental NPV Cost Results (2018 to 2030)

	Case 1: Balanced Procurement ($MM)	Case 2: High Wind Scenario ($MM)	Case 3: High Solar Scenario ($MM)	Case 4: Maximize Local Scenario ($MM)	Case 5: High Wind and Maximize Local Scenario ($MM)
Low Market Price	$1,123	$1,073	$1,181	$1,133	$1,085
Base Market Price	$1,169	$1,119	$1,227	$1,179	$1,131
High Market Price	$1,341	$1,292	$1,399	$1,351	$1,304

Notes:
The changes in the market pricing impacts the Cases similarly; the high market price case is 115% of the base market price case and the low market price case is 96% of the base market price case

Table 1-3 Impact of a 30 Percent ITC Extension Through 2030 (2018 to 2030)

	Case 1: Balanced Procurement ($MM)	Case 2: High Wind Scenario ($MM)	Case 3: High Solar Scenario ($MM)	Case 4: Maximize Local Scenario ($MM)	Case 5: High Wind and Maximize Local Scenario ($MM)
Current ITC Schedule	$1,169	$1,119	$1,227	$1,179	$1,131
ITC Extension through 2030	$1,145	$1,108	$1,188	$1,156	$1,122
Change %	-2%	-1%	-3%	-2%	-1%

Table 1-4 Incremental NPV Cost Impact of Adjusted Altamont Wind Pricing (2018 to 2030)

	Case 4: Maximize Local Scenario ($MM)	Case 5: High Wind and Maximize Local Scenario ($MM)
Current Altamont Pricing	$1,179	$1,131
Revised Altamont Cost	$1,183	$1,135
Change %	0.3%	0.3%

A high-level estimate of jobs and local impacts from the five main cases was performed. To estimate the impact, the number of jobs created by wind and solar PV projects was estimated using values developed by the International Renewable Energy Agency (IRENA) from a 2013 Renewable Energy Jobs report (which applies US-specific factors as developed by the National Renewable Energy Laboratory). As shown in Table 1-5, the High Solar scenario has the highest estimated job creation. It should be noted that these are not necessarily new jobs, and the impact is not cumulative. Cases 4 and 5 include an estimate of local resources based on the number of local wind and solar capacity installed in 2020, and it is maintained every subsequent year.

Table 1-5 High Level Annual Jobs Estimate, by Case (2018 to 2030)

	Case 1: Balanced Procurement			Case 2: High Wind Scenario			Case 3: High Solar Scenario			Case 4: Maximize Local Resources					Case 5: High wind and Maximize Local Resources				
	Wind	Solar PV	TOTAL	Wind	Solar PV	TOTAL	Wind	Solar PV	TOTAL	CA Wind	Local Wind	CA Solar	Local Solar	TOTAL	CA Wind	Local Wind	CA Solar	Local Solar	TOTAL
2018	605	1,061	1,666	916	540	1,456	242	1,698	1,940	605		1,100		1,705	920		540		1,460
2019	1,155	2,094	3,248	1,806	839	2,645	486	3,350	3,836	767	408	1,420	674	3,269	1,302	408	405	674	2,789
2020	375	699	1,074	567	414	981	248	1,119	1,367	372	3	693	7	1,075	563	3	409	7	982
2021	501	754	1,255	571	418	989	250	1,061	1,311	438	3	747	7	1,195	567	3	413	7	991
2022	626	1,110	1,736	999	448	1,447	252	1,774	2,026	623	3	1,104	7	1,736	1,056	3	437	7	1,503
2023	26	656	682	402	26	428	12	688	700	265	3	450	7	724	399	3	22	7	431
2024	329	62	391	284	426	710	12	894	906	267	3	54	7	330	341	3	22	7	373
2025	477	62	539	286	30	316	12	602	614	269	3	454	7	732	283	3	222	7	515
2026	33	502	535	470	30	500	315	107	422	271	3	58	7	338	358	3	24	7	392
2027	275	466	741	50	430	480	15	707	722	273	3	458	7	740	348	3	224	7	582
2028	277	70	347	352	34	386	317	113	430	33	3	462	7	504	48	3	426	7	484
2029	218	356	575	240	344	584	17	909	926	380	3	66	7	456	427	3	30	7	467
2030	38	73	111	54	37	91	17	121	138	36	3	66	7	111	52	3	30	7	91

The load forecast for CleanPowerSF includes the initial views for the expected load at full buildout, taking into account statewide forecasted impacts of distributed energy resources (DERs) such as customer-sited solar PV, electric vehicles (EVs), energy efficiency (EE), and customer-sited energy storage (ES). Once CleanPowerSF reaches full enrollment, a better understanding of the actual load and customer types served will support a refined assessment of the impacts and potential contributions of DERs on the CleanPowerSF system in future IRPs. Future approaches and program opportunities that may be undertaken by CleanPowerSF in the future include the following:

- **Energy Efficiency:** Load growth projections developed by CleanPowerSF utilize future growth forecasts developed in the California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) taking into account the mid-AAEE (Additional Achievable Energy Efficiency) estimates, consistent with direction provided by the California Public Utilities Commission (CPUC) for IRP forecasting. While CleanPowerSF does not currently administer an EE program using CPUC funds for benefit of its customers, this arrangement will be evaluated in the future.

- **Solar PV:** Past work performed by Black & Veatch estimates that an achievable goal for citywide rooftop solar in San Francisco would be in the 50 to 70 MW range. Data from the GoSolarSF program show that San Francisco is well on its way to achieving this goal, with roughly 40 MW installed through mid-2017. Now that the CCA has begun in San Francisco, existing programs could be modified or additional programs could be rolled out (e.g., a community solar program could provide options for residents who may not be able to install solar themselves); the goal would be to provide additional incentives for customer-supported solar. As decisions are made on these types of programs, the load forecast will be modified to reflect the likely impacts.
- **Electric Vehicles:** The current penetration of EVs is taken into account in the current load forecast, and as more EVs are seen in the CleanPowerSF service territory, both the total amount of electric demand and the shape of the demand profile will be affected. CleanPowerSF will have the option in the future to provide customer incentives for the use of EVs if deemed useful to help meet City goals. Sonoma Clean Power has seen positive feedback from its recent pilot programs to support EV usage.
- **Customer-Sided Storage:** Currently, because of the high capital cost, customer-sided storage is limited and has little impact on net load. Given the low cost of market-based capacity and ancillary services to provide the benefits that storage can bring to CleanPowerSF, there is likely to be limited value to incentivizing customer-sided storage. However, customers will be adopting storage regardless of the actions of CleanPowerSF; the levels and impacts should be reviewed to determine the level that should be appropriately modeled in the load forecast.

1.4 Next Steps

On the basis of the analysis performed in the previous section, the following key proposed activities shall be undertaken by CleanPowerSF:

1. **Establish a regular and transparent procurement cycle to meet City and State electricity resource requirements and goals.** CleanPowerSF should implement regular power solicitation cycles so that it can continue to procure the energy and capacity it needs to meet its power content and reliability requirements and goals through 2030.
2. **Develop a portfolio featuring a technologically and geographically diverse mix of renewable resources, while prioritizing investment within the Greater Bay Area, to the extent technically and economically feasible.** CleanPowerSF's IRP analysis has shown that a mix of wind and solar resources is cost-effective. CleanPowerSF will consider these findings (balancing them with program goals such as job creation and local investment) as it continues to procure a diverse and reliable portfolio for its customers, and will review how these findings may change with developments in technology (e.g., increased affordability of energy storage) and evolving market costs.
3. **Procure energy from local wind resources as available and cost-effective.** From analysis performed as part of this IRP and expectations by Black & Veatch, local Altamont Pass wind resources appear to be cost competitive with other statewide options. CleanPowerSF should look to procure these resources where available because of their cost and alignment with the goals of CleanPowerSF to support local projects.
4. **Lock in near-term pricing for renewable resources.** On the basis of the PPA prices received in the most recent Request for Proposal (RFOP), the results of the market price analysis, and projections for changes in federal incentives, locking in near-term pricing for

an extended contract period makes economic sense. The benefits of these prices should be weighed against other risk factors facing CleanPowerSF, such as opt-out rates and regulatory changes.

5. **Active portfolio management to stay competitive in a rapidly evolving energy market.** As California moves toward 50% renewable energy by 2030 – and as some load-serving entities, such as CleanPowerSF, set goals to get there even sooner – we face a rapidly-changing set of procurement opportunities. New renewable generation, breakthroughs in renewable technology, and shifting CAISO market costs all may shift where the best procurement opportunities lie for pursuit of CleanPowerSF's program goals. CleanPowerSF will continue its practice of active portfolio management and regular market review to mitigate risks and review new opportunities.

2.0 CleanPowerSF Background and Growth Trajectory

Consistent with utility industry best practices, CleanPowerSF will conduct a biennial IRP process to identify near-term and mid-term power supply needs and inform annual power purchasing activities, taking into account demand reductions projected to result from EE and demand response activities. The IRP process will (1) quantify CleanPowerSF's energy resource needs over a 10 year planning period[1]; (2) prioritize resource acquisition preferences and set forth other relevant energy supply policies; and (3) provide guidance to programmatic purchases and activities, electricity purchasing, and resource development processes undertaken by CleanPowerSF staff. The IRP process will be conducted and presented to the Commission each year following the first year of service.

This IRP will be utilized to guide CleanPowerSF's long-term procurement and portfolio management planning as it expands to offer service to all of San Francisco. As this IRP comes at a time of program growth and the initiation of long-term contracts, its analysis focuses on optimal acquisition of bulk energy supply to serve CleanPowerSF's growing load over time. This IRP will also addresses initial analysis and planning on demand-side management, EE and local DERs; subsequent IRPs will do so in greater depth.

CleanPowerSF began offering service to its customers in May 2016 and, as of January 2018, serves an electricity load of approximately 60 MW average demand across more than 75,000 customers, representing approximately 20 percent of the accounts in San Francisco. CleanPowerSF has adopted a goal of completing customer enrollment citywide by 2019 and anticipates a large-scale enrollment to move toward this goal in July 2018. CleanPowerSF anticipates full customer enrollment will require the supply of over 400 MW average demand to more than 350,000 customers. Refer to Figure 2-1.

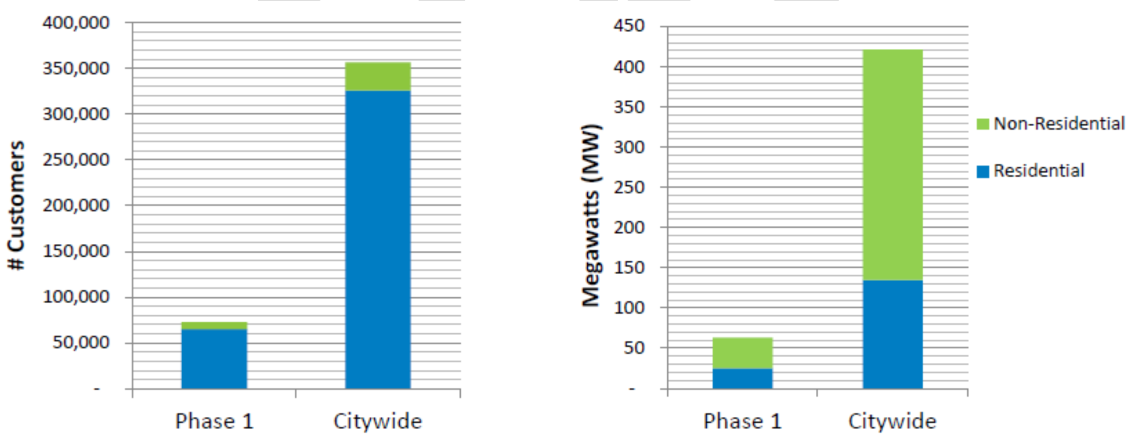

Figure 2-1 Customer and MW Enrollment Projections

[1] CleanPowerSF proposed a 10-year period in its Business Practice Policies; this report considers a 13-year period.

2.1 Guiding Program Growth

2.1.1 Program Goals

As CleanPowerSF plans its growing supply portfolio, it is guided by its Business Practice Policies, and the four following program goals adopted by its Commission:

- **Lead With Affordable and Reliable Service:** CleanPowerSF is committed to providing service that is reliable and affordable for all San Franciscans. To do so, CleanPowerSF pursues the lowest cost energy supply possible that also satisfies its other program goals. Sourcing the most affordable energy requires both execution of desirable, low-cost contracts, and strategic management of its position to allow CleanPowerSF to take advantage of market opportunities while minimizing risk.
- **Provide Cleaner Electricity Alternatives:** A critical element of CleanPowerSF's mission is to provide cleaner energy alternatives to San Francisco. Today, CleanPowerSF offers a "Green" default electricity supply product that is 40 percent renewable and 78 percent GHG-free (compared to Pacific Gas and Electric's [PG&E's] default offering that close to 33 percent renewable and 69 percent GHG-free). CleanPowerSF's second electricity supply product is called "SuperGreen" and features 100 percent renewable and GHG-free energy at a slight rate premium over the Green product. CleanPowerSF plans to increase the percentage of renewable energy and GHG-free energy in its default "Green" product to be at least 50 percent renewable by 2020 and 100 percent GHG-free by 2030.
- **Invest in Local Renewable Projects and Local Jobs:** Currently, close to half of CleanPowerSF's Green product renewable energy supply and 100 percent of the SuperGreen product renewable energy supply is sourced from renewable energy facilities located in the nine Bay Area counties. As it sources additional renewable energy supply to meet the demand of the program at full enrollment and the City's target of at least 50 percent renewable energy by 2020, CleanPowerSF anticipates procuring up to 500 to 600 MW of new (to-be-built) renewable energy capacity. This commitment to developing new renewable resources under (mostly) long-term (greater than 10 years) PPAs will spur clean energy job creation in plant construction and operations and maintenance.
- **Provide for Long-Term Rate and Financial Stability:** CleanPowerSF manages its program and its rates to minimize rate increases and provide a stable source of electricity for its ratepayers. CleanPowerSF's Business Practice Policies – specifically its Supply Management Policy, Reserves Policy, and its Rate Setting Policy – ensure prudent supply portfolio and position management to manage financial risk and back its rates with a robust rate stabilization reserve.

2.1.2 City Goals and Policies

The following City policies regarding energy supply product content continue to guide CleanPowerSF procurement planning:

- **Ordinance No. 81-08**: In Ordinance 81-08, the Board of Supervisors articulate the goal of having a GHG-free electric system by 2030 and meeting all City electricity needs with renewable and GHG-free sources.

- **Proposition H**: Passed in 2015, this proposition guides CleanPowerSF to prioritize serving its customers with electricity generated within California and San Francisco when possible and limit the use of Product Content Category 3 (PCC3) to the extent feasible.
- **50 Percent by 2020**. On Earth Day 2017, the mayor of San Francisco announced a new City goal of a 50 percent renewable electricity supply by 2020 – a goal made possible by the CleanPowerSF program's plans to increase its renewable supply purchases. This goal was adopted for the CleanPowerSF program in the SFPUC Resolution 17-0102, which directs that "renewable energy content of the Green (default) product from 35 percent to 50 percent by the end of 2020, or sooner if possible."

Since its launch, CleanPowerSF has utilized primarily Product Content Category 1 (PCC1) renewable energy – energy generated and/or delivered directly into California – in its renewable energy supply, and has not made any purchases of Product Content Category 3 (PCC3). As it approaches program expansion over the next 2 years, CleanPowerSF will continue to focus on procuring principally PCC1 resources to the extent cost-effective and feasible, given available renewable energy supply. CleanPowerSF has also set a policy limiting its purchases of nonrenewable energy to energy generated using natural gas and large hydro; CleanPowerSF will not purchase power directly from nuclear or coal fired generators.[2]

Using the guidance of the City's 100 percent GHG-free by 2030 and 50 percent renewable by 2020 policies, CleanPowerSF is planning its energy supply with the target annual product content trajectory for its Green product portfolio as shown in Table 2-1.

Table 2-1 Renewable and GHG-Free Goals

CONTENT GOALS	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Renewable	45%	48%	50%	52%	54%	56%	58%	60%	62%	64%	66%	68%	70%
GHG-Free	82%	83.5%	85%	86.5%	88%	89.5%	91%	92.5%	94%	95.5%	97%	98.5%	100%

2.1.3 Regulatory Requirements

Renewable Portfolio Standard

California's RPS program sets minimum procurement requirements for renewable energy within an electricity retail seller's portfolio. With the passage of Senate Bill 350 in 2015, the State Legislature increased the statewide RPS floor from 33 percent in 2020 to 50 percent by 2030. The CPUC, which oversees the implementation of the RPS program and compliance for investor-owned utilities, energy service providers, and community choice aggregation programs, has set procurement requirement floors for each compliance period and targets for each year within a compliance period. RPS requirements are defined in terms of a total RPS percent of an electricity seller's total procured supply, as well as percent breakdown within that RPS requirement. Refer to Table 2-2.

[2] "Product Content Policy." *CleanPowerSF Business Plan*, December 2015.

Table 2-2 RPS Compliance Periods and Amounts

COMPLIANCE PERIOD	CALENDAR YEAR	TOTAL PROCUREMENT REQUIREMENT	OF TOTAL:		
			% PCC1	% PCC2	% PCC3
1	2011-2013	20.0%	≥50.0%	≤50.0%	≤25.0%
2	2014-2016	21.7% to 25.0%	≥65.0%	≤35.0%	≤15.0%
3	2017-2020	27.0% to 33.0%	≥75.0%	≤25.0%	≤10.0%
	2021-2030	33% to 50%			

RPS Long-Term Contracting Requirement

In addition to increasing the amount of renewable energy that a retail seller of electricity must include in its portfolio between now and 2030, the Clean Energy and Pollution Reduction Act (SB 350) significantly increased the amount of renewable energy a retail seller must procure under long-term contracts. Starting in 2021, 65 percent of the RPS energy used to meet the RPS compliance period (2021 to 2024) must be from contracts of 10 years or more.

Energy Storage

The CPUC has established energy storage procurement targets for CCAs and other load-serving entities as a result of the California Energy Storage Bill (Assembly Bill [AB] 2514). CCAs must target energy storage procurement of at least 1 percent of their forecasted 2020 peak load. The applicable CPUC decision established an energy storage procurement target for CCAs and electric service providers equal to 1 percent of their forecasted 2020 peak load; this procurement target must also be satisfied by 2020. CleanPowerSF's peak load in 2020 as currently projected is 640 MW, which would require CleanPowerSF to procure 6.4 MW of energy storage.

Resource Adequacy

The CPUC requires all retail energy-providing load serving entities to demonstrate that they have procured in advance sufficient electric energy capacity for the California power system to reliably meet system coincident peak load. The following are three types of resource adequacy for which CleanPowerSF must procure and make annual monthly compliance filings on to meet CPUC requirements:

- **System requirements** are determined on the basis of each load serving entity's (LSE's) CEC adjusted forecast plus a 15 percent planning reserve margin.
- **Local requirements** are determined on the basis of an annual California Independent System Operator (CAISO) study using a 1 to 10 weather year and an N-1-1 contingency.
- **Flexible Requirements** are based on an annual CAISO study that currently looks at the largest 3 hour ramp for each month needed to run the system reliably.[3]

[3] "Resource Adequacy." California Public Utilities Commission website. http://www.cpuc.ca.gov/General.aspx?id=6307&cmsMode=Preview.

Resource adequacy may be purchased through long-term contracts but is more commonly purchased in shorter term transactions.

2.1.4 Projected CleanPowerSF Energy Use and Peak Demand

As CleanPowerSF grows, it must procure energy supply appropriate for its growing customer demand. CleanPowerSF's analysis of its future load potential contains its current customers and all remaining City of San Francisco customers not served by Hetch Hetchy Power or by Direct Access (DA).[4] Together these customer groups currently use approximately 4 million megawatt-hour (MWh) annually (or 460 MW of average demand).

CleanPowerSF has analyzed historical electricity consumption data for San Francisco to understand expected variations in peak demand by month and by time of day. CleanPowerSF expects its full customer load following citywide enrollment in 2020, to have peak demand of just over 600 MW (Figure 2-2).

CleanPowerSF's expected full-enrollment aggregate hourly average demand peaks in the late afternoon at approximately 480 MW. Peak demand is also highest in the late afternoon, peaking at just over 600 MW (Figure 2-3).

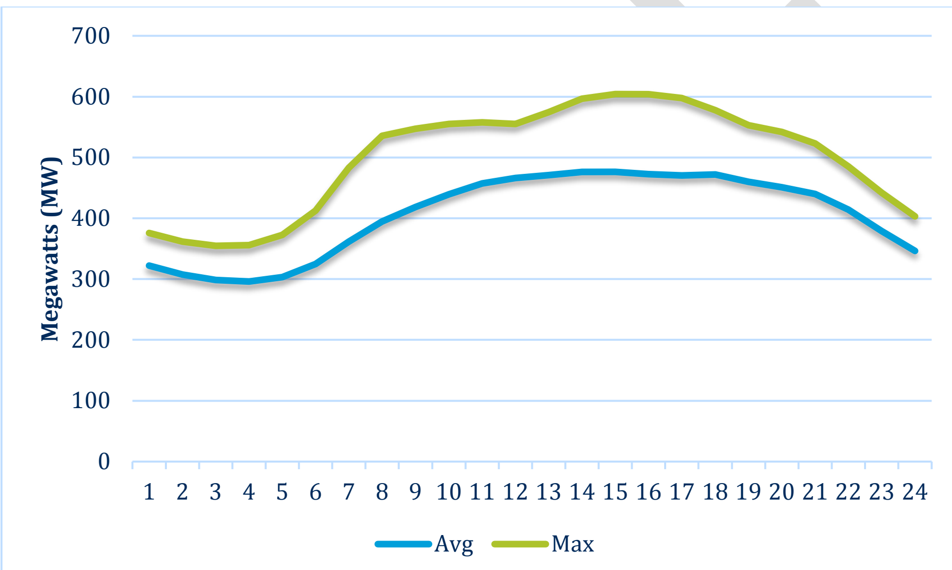

Figure 2-2 Projected Hourly Demand (Full Scale in 2020)

Through a growth planning process, CleanPowerSF has created a plan for Citywide expansion that includes auto-enrollment of new customers in 2018 and 2019, and anticipates to be offering service to all eligible customers by mid-2019. CleanPowerSF has built an hourly demand projection of the City's anticipated load following 2018 and 2019 program expansion.

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[4] POU customers are not eligible to become CCA customers under AB117. CleanPowerSF will consider engaging DA customers for enrollment in the future but will not be auto-enrolling DA customers under the current CleanPowerSF growth plan; auto-enrolling these customers could break its ESP supply contracts and may imperil its ability to return to DA service, participation that is capped and currently has a waiting list for new participants.

2.2 Current and Upcoming Program Offerings

2.2.1 Green and SuperGreen Products

The CleanPowerSF default energy offering (Green product) is currently 40 percent renewable and 78 percent GHG-free. CleanPowerSF also offers a SuperGreen product that is 100 percent renewable and GHG-free. CleanPowerSF's SuperGreen product is sourced from local resources.

CleanPowerSF plans on increasing the percentage of renewable energy and GHG-free energy in its default Green product to be 50 percent renewable by 2020 and 100 percent GHG-free by 2030.

2.2.2 Feed-in-Tariff Program

The CleanPowerSF Feed-in-Tariff (FiT) program, expected to be launched following full enrollment, is anticipated to invite offers of energy from San Francisco-sited, renewable, RPS-compliant projects sized up to 1 MW. The FiT program will support CleanPowerSF's goal to source greater renewable energy and promote diverse local energy development.

2.2.3 Net Energy Metering Program

CleanPowerSF's Net Energy Metering (NEM) program allows customers who install an on-site renewable energy system to receive bill credits when they generate more power than they need. CleanPowerSF offers customers credits at a Net Surplus Compensation rate 2 to 3 times greater than PG&E's comparable program. CleanPowerSF's NEM program, launched in May 2016, has, to date, auto-enrolled NEM rate customers in three City supervisory districts and made its programming available for signup citywide; additional NEM customers will be auto-enrolled quarterly (following customer true-up dates) as CleanPowerSF auto-enrollment continues under its growth plan. To date, CleanPowerSF has enrolled approximately 2,000 NEM customers, with a citywide NEM population of 8,577. Roughly 14 percent of the NEM population within San Francisco is projected to be net generators over the course of the year and be eligible for Net Surplus Compensation.

2.2.4 GoSolarSF Program

GoSolarSF is a City program that has helped residents and businesses install thousands of kilowatts of solar energy on rooftops across San Francisco, providing financial incentives on the basis of solar system size. GoSolarSF reduces participants' electricity bills and furthers the City's carbon-free goals.

2.3 Projected Procurement Needs

2.3.1 Current Supply Portfolio

CleanPowerSF launched its program sourcing its supply from two primary contracts. Calpine Energy Services is providing shaped conventional energy with a specified amount of renewable energy and a GHG emissions cap. This contract has served CleanPowerSF since its 2016 launch and concludes in 2019. CleanPowerSF receives renewable wind energy from Avangrid's Shiloh I Wind Project in the Montezuma Hills of Solano County. This contract has served CleanPowerSF since its 2016 launch and concludes in 2021.

Following its launch, CleanPowerSF also entered into a long-term contract to purchase a portion of the Sunset Reservoir Solar Project in San Francisco through 2026, and renewable energy from wind projects in the Tehachapi region. CleanPowerSF has also acquired short-term hydroelectric energy supplies from Hetch Hetchy Power.

In 2017, following approval of the CleanPowerSF Growth Plan by its Commission, CleanPowerSF began the process of procuring additional energy for growth through two separate request for offers (RFOs): in July 2017, CleanPowerSF issued an RFO seeking renewable energy products; in August 2017, CleanPowerSF issued a separate RFO seeking shaped and/or block conventional, renewable, and GHG-free energy products.

In spring of 2018, CleanPowerSF executed contracts for multiple types of energy products to supplement its existing contracts and in preparation for upcoming program expansion and growing renewable and GHG-free content goals. These products include:

- Renewable, geothermal energy (PCC1) provided by Calpine Energy Services from The Geysers geothermal plant in Lake/Sonoma Counties starting May 2018, contracted through 2022;
- Renewable, solar energy from new development in Lancaster, California provided by sPower starting in 2019 through 2031;
- Renewable, wind energy from both existing wind plants, and spurring new development at a repower project provided by Terra-Gen, LLC starting in 2018 through 2035; and
- Renewable, carbon-free and conventional energy products from various suppliers provided to 2021.

2.3.2 Projected Procurement Needs

For the purpose of long-term planning, CleanPowerSF has analyzed its growth to its full citywide potential customer base assuming enrollment of remaining customers in two large phases: one in July 2018 and one in Spring 2019 (this follows the two-stage scenario for program growth described in the CleanPowerSF Growth Plan). Using this assumption, the performance of the program's existing contracts, and the product content goals and anticipated load shape described above, CleanPowerSF is planning for procurement (and/or has procurement actively under way) to meet the unprocured energy need shown on Figure 2-4.

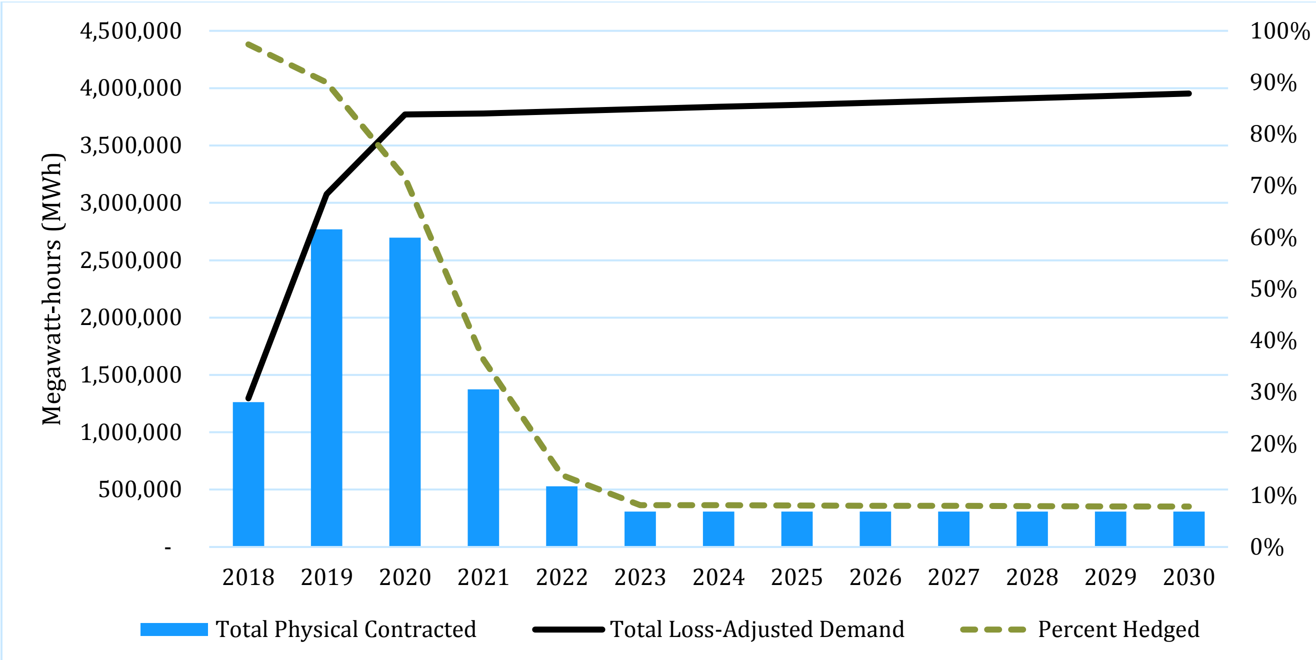

Figure 2-3 CleanPowerSF Demand Against Contracted Physical Energy

2.3.3 Forward Position Management

Energy supply required by customer demand but not yet procured for is considered a load-serving entity's "open position." Contracting for a long-term and narrowing a CCA's open position may appear to be a way to take care of securing supply at a favorable price – and shrinking market risk by hedging against CAISO prices. However, locking in a specific price and quantity for the long term in an evolving energy market may create other risks, such as being tied to an over-market price (where competitors such as PG&E may not be), or having to sell energy purchased in excess on an unfavorable spot market. As shared in the CleanPowerSF May 2017 Growth Plan, CleanPowerSF anticipates planning its procurement to leave a narrow open position 1 year out, but that strategic open position grows 2 and 3 years out from the present to represent more than 50 percent of its portfolio in the long term. This open position strategy may shift in response to market and/or regulatory shifts or unexpected procurement opportunities. .

3.0 Study Design

3.1 Objectives

The analysis performed as part of this IRP has both near- and long-term objectives. In the near term, the analysis is used to inform the procurement decisions that CleanPowerSF is making as the full subscription to the CCA is rolled out in 2018 and 2019. Long term, the analysis will be used to forecast the resources and actions necessary to meet state and City goals for renewable and GHG-free energy by 2030 and beyond, and inform CleanPowerSF's IRP Compliance Filing to the California Public Utilities Commission (CPUC). To cover these objectives, a variety of scenarios were performed that used different types of renewable procurement (i.e., High Wind, High Solar, balanced, and maximize local resources) to understand the impact on anticipated total procurement costs. Sensitivities were also performed to understand the impact of low- and high-market prices, an extension of the ITC, and higher local wind costs.

The modeling and approach that was taken as part of this IRP reflected the unique situation faced by a CCA. Since CleanPowerSF does not own its own generation or firming capacity to meet load, it is important to model the design to reflect the interactions with the market necessary to meet overall load and resource adequacy requirements. This was a driving factor behind the approach taken to the IRP.

In performing the work, CleanPowerSF utilized data and information gathered by the SFPUC from past work performed on future CCA needs and resources likely available to meet load. Information developed by Black & Veatch to support these activities was applied, along with Black & Veatch's market forecast for wholesale power and resource adequacy costs. Sensitivity cases, reflecting the greatest uncertainties in model inputs, were the final steps to providing the final recommendations for the activities to pursue.

3.2 Methodology

CleanPowerSF worked with Black & Veatch to assist with development of an IRP model that provides analysis for future investment and energy procurement options. Information about the model, approach, and cases is provided in the following subsections.

3.2.1 Modeling Tool

Black & Veatch created two Excel-based tools exclusively for CleanPowerSF. The first tool (Net Short Model) determined the yearly net short/net long position on the basis of load, existing resources, and projected renewable energy resources available to meet renewable energy and GHG-free energy procurement goals. During that time frame, compliance with several requirements and goals is assumed, including the following:

- The California RPS requirement.
- The demand for Supergreen (100 percent renewable energy) from customers.
- The City's goals for procuring additional RPS eligible renewables beyond state-mandated requirements, as well as for GHG-free power.

The second model (Procurement Impact Model) balanced load with existing and generic resources on an hourly basis from 2018 to 2030. This model tracks several key metrics to ensure compliance with critical California laws and regulations, and City goals, including the following:

- Hourly power sales.
- Hourly power purchases.
- Monthly resource adequacy (RA) needs.
- Renewable energy (RPS eligible, PCC1) power, including banking.
- Local resources procured (MWh and cost).
- Annual and long-term NPV incremental costs for each scenario.
- GHG emissions in metric tons.

3.2.2 Modeling Approach

The general goal of the modeling approach developed by CleanPowerSF and Black & Veatch was to identify the optimal combination of renewable resources to pursue program goals – including affordability, and local development – while meeting City renewable and GHG-free goals (and state RPS compliance requirements). The initial modeling to review procurement options was timed to coincide with CleanPowerSF's major procurement efforts in 2017 and 2018, as a way to inform which projects make the most sense to procure from the solicitation, particularly in terms of their relative benefits and costs. The modeling was then updated by Black & Veatch in May and June of 2018.

3.2.2.1 Costs and Emissions as Model Outputs

Black & Veatch developed an incremental cost approach to model development and for the purposes of cost analysis, focused on only those factors that change between cases. In other words, the goal was to identify how well these cases compared to each other, instead of estimating the total costs and total impact of any one case. Because of this, the following items were expressly not included in the modeling:

- Costs for existing resources already under contract.
- Cost for RA that will be the same for all cases (e.g., flex RA).
- Transmission access charges (not applicable for CCAs).

Energy storage costs are also excluded, as the same energy storage procurement was applied to all Cases. Incremental costs do include the net of new energy product purchases to fill CleanPowerSF's net short and System and Local RA obligations, and resulting sales from hourly excesses. Therefore, the economic results shown in this analysis do not reflect the total cost to CleanPowerSF to procure resources for its customers but, rather, are a metric for comparison between cases.

Greenhouse gas emissions associated with each portfolio mix are also presented; these emissions represent total emissions associated the portfolio, not incremental

3.2.2.2 CleanPowerSF Cases

It was determined that only solar and wind would be considered for new renewable procurement. While other renewable energy resources were considered, other resources were deemed to be too expensive relative to wind and PV to be included in this round of modeling, as discussed in the next section.

Three cases were developed with different levels of wind and PV to see which renewable resource combination is most advantageous by comparing the incremental cost of each case. Different levels of the most economic California wind and solar resources were added at appropriate levels on the basis of the case definition. Since CleanPowerSF and its stakeholders also have a goal to maximize local (Bay Area) projects, two other cases were added to assess the value of this option relative to the others considered. Finally, a set of sensitivities was run to help determine how robust the results are when key input assumptions change.

Case 1: Balanced Procurement Scenario

The first case examined procurement of a balanced renewable net short of wind and solar PV, with a composition of 50 percent wind and 50 percent solar. A total equivalent number of MWh from the most economic, generic wind and solar plants in California were assumed to meet the requirements. This was done on an energy volume basis because the RPS and City goals are based on a percentage of the total energy needed to meet load.

Case 2: High Wind Scenario

In the high wind case, approximately 77 percent of the energy produced to meet the program's renewable net short was assumed to come from wind resources, and 23 percent was from solar PV. The same resources investigated in Case 1 were applied to Case 2, just in a different ratio of total energy.

Case 3: High Solar Scenario

The majority of the energy (approximately 77 percent) produced to meet program's renewable net short in the high solar case was assumed to come from solar PV and 23 percent was from wind, using the most economic generic resources. As with Case 2, the same overall resource performance from Case 1 was applied to Case 3.

Case 4: Maximize Local Resources Scenario

This case considered the opportunity of procuring Bay Area resources to supplant a portion of the resources evaluated in Case 1. First, this analysis started from Case 1: Balanced Procurement, with 50 percent each of wind and solar. Then, 67 MW total of wind and solar PV resources in 2020 (33.7 MW each) were replaced with representative local resources. The resources were originally identified in the "Renewable Energy Assessment" that Black & Veatch completed for the SFPUC in 2014.[5] Local resources were assumed to come on line in 2020.

The cost and performance estimate inputs were updated for current 2017 conditions and are further detailed below. The solar projects selected were based on the most economic solar PV that could be developed on SFPUC-owned lands in the Bay Area (Sunol and three reservoir rooftop projects totaling 33.7 MW), alongside an equivalent amount of wind assumed to be from repowered projects in the Altamont Pass area. The technology-specific costs were adjusted to reflect technology improvements and long-term cost trajectories projected by Black & Veatch, with near-term wind and solar costs (2018 to 2020) adjusted to reflect the sample PPA prices from the August 2017 CleanPowerSF renewable energy RFO. The solar projects are estimated to cost more than solar resources further away, and the Altamont power repowering project is a competitive project,

[5] Olson, Scott et. al, (2014), "Renewable Energy Assessment," Black & Veatch, January 10 http://sfgov.org/lafco/ftp/uploadedfiles/lafco/RFP/18%20-%20SFPUC%20Renewable%20Energy%20Assessment%20%282014%29.pdf

expected to cost slightly more than wind projects further away, but will be limited by the total repowering opportunity.

Case 5: Maximize Local Resources Scenario / High Wind Resource Balance

This case combined the higher wind-to-solar resource balance ratio from Case 2, with the procurement of local resources in Case 4. Therefore, the same mix of resources is used in Case 5 as in Case 2, with the exception of the local resources input from Case 4.

Sensitivities

Sensitivities were conducted to test the impact of variation of inputs on the results. These included changes to the wholesale energy market price, ITC extension, and higher cost inputs for local wind projects.

High and Low Energy Market Price

As is customary for IRP analyses, the possibility that natural gas prices, and thus electricity prices, could vary from the base case projection was taken into account. To address this possibility, a low energy market price sensitivity and a high energy market price sensitivity were examined as outlined below.

The high and low market prices were developed using the following methodology. First, Black & Veatch produced a new base case California wholesale market price forecast so that it could be used in the analysis. Black & Veatch then estimated the adder that should be applied to the hourly base case to create the low and high market prices. The same absolute differences between the base, high, and low cases that were developed in the SFPUC POU IRP were used here,[6] using a bottoms-up estimate of wholesale market price impacts. Next, these absolute, incremental annual difference values were applied to the revised hourly wholesale market price forecast to determine the high and low hourly sensitivity values. In general, the energy market price for the low incremental cost case is about 10 percent lower than the base forecast, and the energy market prices for the high incremental cost case is about 20 percent higher. An adder for all hours in a given year was used to ensure that any zero market clearing price hours (or near zero hours) would be appropriately shifted in the sensitivity. This method still shifts the market price for any hour when the market price was zero; using a percentage adder instead was ruled out because it would still result in an energy market price of zero.

ITC Extension

Part of the goal of this IRP analysis is to help CleanPowerSF determine the opportunity presented by the ITC so that it can consider and leverage this opportunity in the timing of its long-term contracts. A sensitivity case was, therefore, performed that extended the current 30 percent ITC through 2030, instead of ramping down from 30 percent starting in 2020 (the current law). While this case is not to be expected in the current political climate, it does capture the impact of the ITC and informs procurement decisions.

Higher Local Wind Costs

To test the impact of potential higher costs for repowering Altamont wind projects, Black & Veatch adjusted Cases 4 and 5 (which feature local procurement). The levelized cost of electricity (LCOE) of

[6] http://sfwater.org/Modules/ShowDocument.aspx?documentid=10704

Altamont was adjusted up 10 percent from the 2020 cost of $44/MWh to test the impact of a higher cost local resource. The goal is to understand the impact of increased incremental cost and price for local wind.

3.2.2.3 Procurement Plan and Analysis Approach

With the cases defined, the next step was to determine the procurement plan using the Net Short Model. The focus was on the near-term years (2018 to 2020) to prepare for and target 2020 compliance with the RPS and the City's goals. After 2020, frequent procurements were added with the goal of managing the net short on an annual basis. The procurement target was to maintain a 1% or less variance of the renewable procurement to the annual renewable targets. A variety of California-specific, generic wind and solar resources were identified according to the overall goal of the cases. Wind and solar projects were identified in more than one location to provide the analysis with wind and solar that each had unique resource shapes and that were used to meet the procurement plan needs; this replicates the fact that the solar and wind resource are specific to particular locations. Different resource locations were assumed to come on line as needed to provide a variety of renewable resource shapes in the analysis.

Once the procurement plan was determined for all five cases, each was entered into the Procurement Impact Model, along with all other required assumptions. In turn, the model provided the results for each case, and key metrics were tracked to ensure compliance with California rules and regulations, as well as with City goals. Once the results were captured, they were compared to identify the preferred case after the sensitivities were applied.

3.2.2.4 Monthly Resource Adequacy

CCAs that serve retail load are required to comply with the CPUC's RA program.[7] The CPUC's RA program contains three distinct requirements: System RA, Local RA requirements, and Flexible RA requirements. System requirements are determined based on the each LSE's CEC adjusted forecast, plus a 15 percent planning reserve margin. Local requirements are determined based on an annual CAISO study using a 1 to 10 weather year and an N-1-1 contingency. Flexible requirements are based on an annual CAISO study that currently looks at the largest 3 hour ramp for each month needed to run the system reliably.[8]

Monthly peak values from the 8,760 load forecast with a 15 percent planning reserve margin were used as the monthly System RA requirement over the study period. Capacity from contracted resources was also tracked on a monthly basis using installed renewable nameplate values and the monthly capacity value factor from Table 3-1. Nameplate factors are based on the latest CPUC proposals on renewable RA capacity. [9,10]

Market RA purchases make up any deficit that remains in the monthly System RA after calculating contracted capacity. Market price is based on the Final 2016 RA Report Released by CAISO and CPUC specific to Northern California. RA capacity contracts covering the 2016 to 2020 compliance years were analyzed, and aggregated RA contract prices were reported for NP26 at around $2,000

[7] CPUC RA Website: http://www.cpuc.ca.gov/General.aspx?id=6307&cmsMode=Preview

[8] CPUC RA Website: http://www.cpuc.ca.gov/General.aspx?id=6307&cmsMode=Preview

[9] Solar based on CPUC R.14-10-010 "Monthly LOLE and ELCC Proposal" released 12/16/2016. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451952

[10] Wind based on CPUC D-Staff Proposal RA Obligations and Locational Monthly ELCC Results. Release: 3/25/2016. www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10599

$/MW per month.[11] Since long-term forecasts expect capacity to remain long through much of the analysis period, this value was escalated by 1 percent beyond 2020 for the remaining study period.

Flexible RA is based on CAISO ramp requirements. Because the ramping requirements were assumed to be consistent across all studied scenarios (the selected new renewable resources do not provide Flexible RA) and because the analysis was performed on an incremental basis, Flexible RA was ignored.

Table 3-1 Monthly Capacity Value of Renewable Resource (Nameplate Factor)

MONTH	WIND	SOLAR
1	0.096	0.031
2	0.123	0.019
3	0.149	0.062
4	0.144	0.237
5	0.186	0.287
6	0.175	0.299
7	0.140	0.287
8	0.135	0.249
9	0.118	0.175
10	0.107	0.187
11	0.094	0.037
12	0.102	0.012

To determine the value of Local RA required, local resources were given an RA credit in scenarios where local resources were procured, instead of estimating the total cost of Local RA for all resources. The Local RA credit was the same as the market capacity value assumed System RA market price. This methodology was used because the results show incremental costs relative to each other, which is the goal of informing case selection as part of the IRP process.

3.2.3 Assumptions

For the IRP period (2018 to 2030), hourly data was used every year for the analysis. Load data and existing contract characteristics were provided by CleanPowerSF on an hourly basis. This was supplemented in the model by information on generic wind and solar resources as procurement options, market power forecasts, GHG emissions from market purchases, and financial inputs to determine a recommended path forward for future procurement efforts.

[11] CPUC 2016 Resource Adequacy Report: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453942

3.2.3.1 Load Forecast

CleanPowerSF and Black & Veatch worked with CleanPowerSF's hourly retail load forecast covering 2018 through 2030 (updated and submitted to the California Public Utilites Commission in May 2018), and applied an line loss assumption of 6%. Figure 3-1 shows that the detailed load growth is based on the two-step phase expansion described in the CleanPowerSF Growth Plan (refer to Figure 2-1). The load data includes opt out and vacancy assumptions.[12] It should be noted that after July 2019, the program will be fully enrolled, with load growth forecasted on the basis of statewide projections.

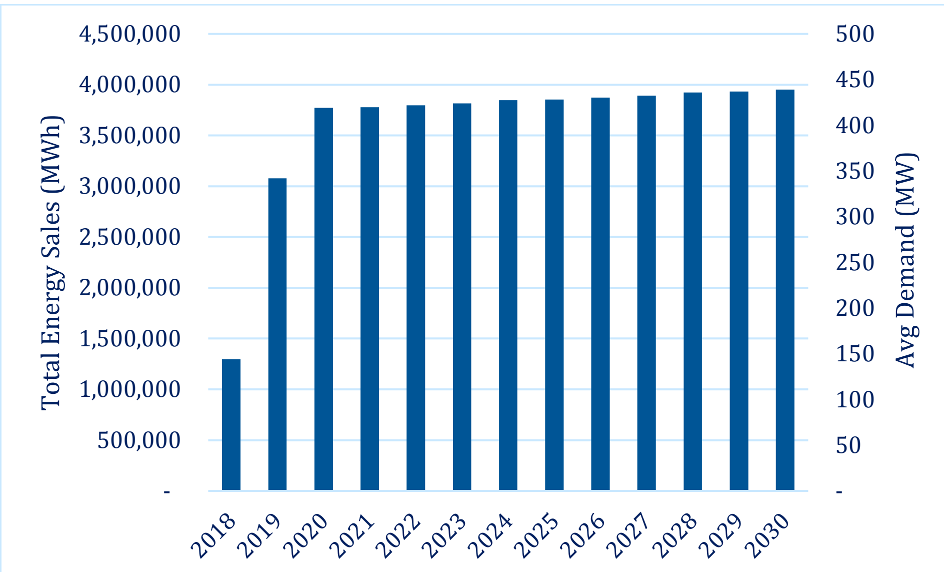

Figure 3-1 Annual Energy Sales and Average Demand (Two-Phase Expansion)

DERs are embedded in the load shape. Further discussion on the anticipated impact of DER is covered in Subsection 4.1.3.

3.2.3.2 Resources

3.2.3.2.1 Existing Resources

CleanPowerSF's existing, or contracted resources, were summarized by year to establish a total physical net short for each year, as well as a net short toward meeting CleanPowerSF's renewable and GHG-free goals for each year. CleanPowerSF's procurement to-date[13] shows procurement for 2018 as nearly complete, with its renewable content goals satisfied by short and medium-term contracts.

[12] A 7 percent opt-out plus vacancy rate was assumed for new customers entering the program as of May 2017, an 8 percent opt-out rate was assumed starting in May 2018, and a 10 percent opt-out rate was assumed starting in May 2019.

[13] This summary of CleanPowerSF procurement reflects CleanPowerSF's position at the time of the finalization of this report. CleanPowerSF maintains an actively managed portfolio in which resources may be bought or sold at any time to manage risk or further program goals.

3.2.3.2.2 Modeled Resources

Once the shape of CleanPowerSF's remaining net short against its long-term goal was verified, renewable resources were modeled by Black & Veatch to fill CleanPowerSF's renewable net short, using updated versions of generic new wind and solar resources that were used in the 2014 Renewable Energy Study[14] developed by Black & Veatch for the SFPUC. These generic resources are California-based, qualify for PCC1 Renewable Energy Credits (RECs), and are applied to model CleanPowerSF's meeting its RPS compliance and renewable and GHG-free goals. The goal with their selection was to represent a variety of locations and resource shapes. The larger generic resources were assumed to represent development in the general area of a particular location. These are incremented up in specific years to meet the RPS and City goals on the basis of the procurement plan.

For wind, two large-scale potential procurement locations were identified in the Solano area from the 2014 study: Montezuma Hills and Walnut Grove. The sites were selected for the combination of economics and uncorrelated production output. Resources in the Altamont Pass were also identified as a potential location for a refurbished wind project that also counts as a local Bay Area resource. The estimated hourly energy production of all three resources was updated using current (2017) wind resource and turbine performance information.

For solar PV, three large-scale resources locations were identified, along with four local solar resources. The three solar locations identified were Midway, Windhub, and Imperial Valley from the 2014 study; each was deemed to be economically competitive and representative of a generic bid that might be received for new resources to supply CleanPowerSF. Their locations also had uncorrelated production output. Performance was updated to reflect a current design basis and 2017 equipment. To assess the option to have local solar resource procurement as part of the CleanPowerSF portfolio, the cost and performance estimates were updated for the following Bay Area solar PV resources from the 2014 study: Sunol, Pulgas Reservoir, Sutro Reservoir, and University Reservoir.

Local wind and solar resources were identified from the 2014 study, and the technology costs were adjusted to reflect technology improvements seen in the market by Black & Veatch and inflation. In the case of local solar resources, the 2014 capital cost (CAPEX) assumption was updated based on National Renewable Energy Laboratory (NREL) CAPEX declines from 2013 to 2017 resulting in approximately 60 percent cost reduction for these resources since the time of the original analysis.[15] Local wind resources have not witnessed such CAPEX declines since 2014, however technological advancements leading to improved performance have occurred. Researchers from the Depeartment of Energy (DOE) attribute these improvements to the more widespread use of larger rotor turbines in conjunction with taller towers.[16]

Table 3-2 shows technology LCOE estimates for 2017. These are the initial basis for project costs for all generic wind and solar projects. The LCOEs below were adjusted using sample PPA prices

[14] http://sfgov.org/lafco/ftp/uploadedfiles/lafco/RFP/18%20-%20SFPUC%20Renewable%20Energy%20Assessment%20%282014%29.pdf

[15] http://www.nrel.gov/docs/fy17osti/68425.pdf

[16] https://www.energy.gov/sites/prod/files/2017/10/f37/2016_Wind_Technologies_Market_Report_101317.pdf

from the August 2017 CleanPowerSF renewable energy RFOand review of other recent industry PPA prices.[17]

Long-term costs (2021+) were based on wind-specific and solar-specific cost curves that were applied to the 2017 estimates in Table 3-2. Black & Veatch then applied technology cost decline assumptions to take into account changes in incentives, equipment pricing, equipment performance, and balance-of-plant cost estimates.

A description of the performance and cost assumptions used in the model is shown in Table 3-2.

[17] https://emp.lbl.gov/pv-ppa-prices

Table 3-2 Generic Wind and Solar Plant Characteristics Used in Modeling

LOCATION	TYPE	CAPACITY FACTOR (PERCENT)	2017 LCOE ($/MWH)
1. Altamont Pass	Local Wind	39.7	44.0
2. Montezuma Hills	Wind	37.5	42.0
3. Walnut Grove	Wind	34.5	42.0
4. Sutro Reservoir	Local Solar	21.9	96.9
5. University Reservoir	Local Solar	23.3	114
6. Pulgas Reservoir	Local Solar	23.4	114
7. Sunol	Local Solar	26.2	48.7
8. Imperial	Solar	33	33.8
9. Midway	Solar	32	34.9
10. Windhub	Solar	34	32.8

Notes:

1. Reflects incremental cost of new generation using typical industry development assumptions (with consideration for August 2017 CleanPowerSF bid responses).
2. LCOEs are at the site boundary and do not reflect delivered prices at load. These numbers are not necessarily what the CleanPowerSF will pay, because of market factors and CleanPowerSF development costs. Prices for future procurement years were adjusted to take into account technological changes and projected availability of federal tax credits.
3. The numbering shown matches the numbers on Figure 3-2.

The analysis assumed that the ITC for solar PV and the production tax credit (PTC) for wind are both available during the analysis period, according to laws in place as of June 2018. Thus, the ITC is taken as a percentage against the capital cost of a solar PV system, according to the cost basis defined by the IRS (85 percent for solar PV). The ITC schedule is shown in Table 3-3; it starts at 30 percent through December 2019 and then ramps down to 10 percent in January 2022.

Both the ITC and PTC can be claimed in the year the project "begins construction." According to recent Black & Veatch wind industry analysis, it appears all wind projects being installed in 2017 and most planned for 2018 have already "began construction" and, thus, secured the option for the 2016 PTC. Therefore, it is assumed that the PTC ramp down schedule is shifted by 2 years for what will be captured by new projects; this schedule is captured in Table 3-3. For solar, the IRP assumes the resource is online January 1 of procurement year. In the analysis, it is assumed that the plant will begin construction in the year prior to procurement year to take advantage of the ITC. For solar technology, the date in Table 3-3 represents the start of construction date (ITC eligibility driver) the plant is assumed to be online the following year.

Table 3-3 ITC and PTC Incentive Schedule Used in Analysis

TECHNOLOGY	12/31/18	12/31/19	12/31/20	12/31/21	12/31/22	FUTURE YEARS
Solar PV	30%	30%	26%	22%	10%	10%
Large Wind (PTC per kWh)	$0.023	$0.018	$0.014	$0.009	NA	NA

A summary of the resource locations, technology (blue is wind, orange is solar), and relative size of each project (based on size of the circle) is shown on Figure 3-2.

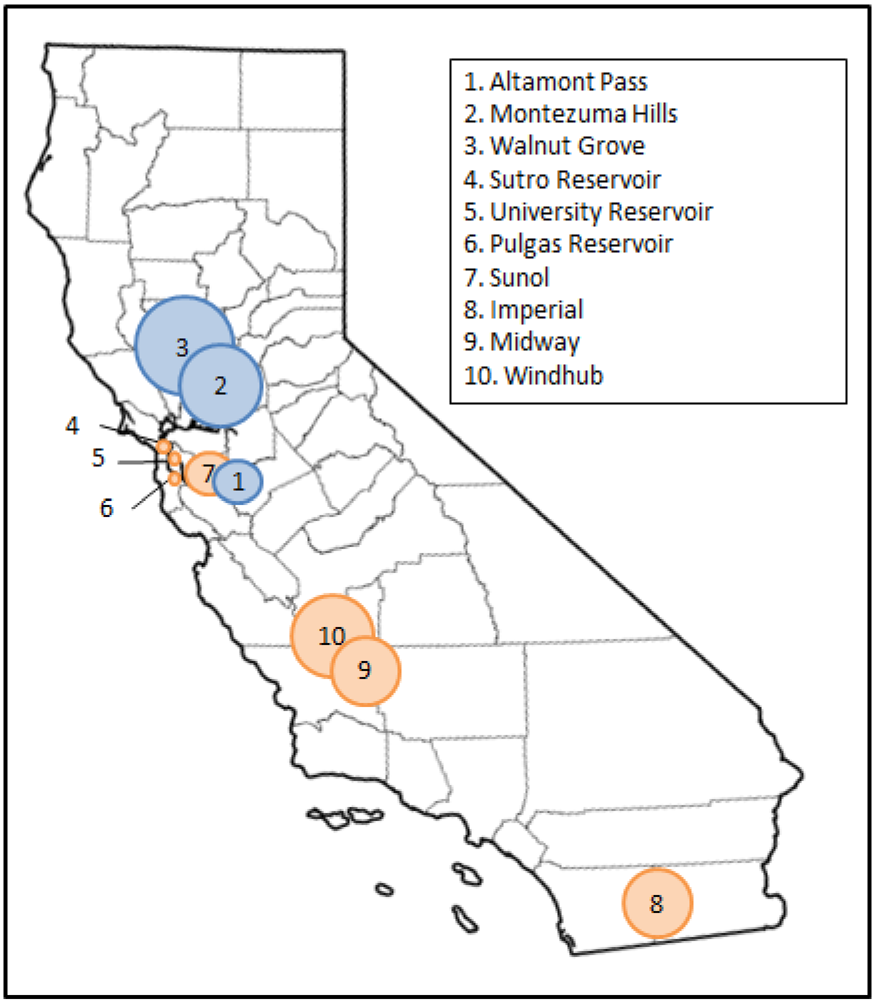

Figure 3-2 Wind and Solar Plant Locations Used in Modeling

Besides the use of wind and solar resources, biomass and geothermal renewable energy options were considered as part of the analysis but not carried through to the modeling phase. According to analysis performed by Black & Veatch for the CPUC's RPS Calculator, average geothermal PPA prices are expected to be around $90/MWh and biomass at $120/MWh. Given these large premiums relative to wind and solar, coupled with low cost capacity for providing RA and wholesale market prices typically much lower than what these baseload plants can provide, these resources were not included in the modeling analysis. This exclusion is for the purpose of limiting variables in this analysis and is not meant to suggest that CleanPowerSF may not leverage biomass and geothermal resources in its portfolio if the pricing of the resource were found desirable.

3.2.3.2.3 Storage

Storage targets for CleanPowerSF are established by AB 2514 (Skinner, Chapter 469, Statutes of 2010),[18] which requires procurement of 1 percent of annual peak load and a deadline for contracts to be in place by 2020 and projects commercially on line by 2024.

In the model, storage is expected to be procured from a lithium-ion battery ES system. Sizing to CleanPowerSF's requirement of 6.4MW per its peak load of 640MW, a total amount equivalent to 6.5 MW, 4 hour duration (26 MWh) is modeled starting in 2024.[19] The model logic uses the storage system state of charge to determine when to charge or discharge the device. The battery is charged when excess generation is available from contracted resources and discharges during a generation shortage.

3.2.3.3 Procurement Plans

The Net Short Model was used to develop the procurement plans shown in Table 3-4 and on Figure 3-3. Procurement starts in 2019 and 2020 (since there are sufficient renewable contracts in place for 2018), with the purpose of bringing CleanPowerSF into compliance with the 2020 state RPS mandate and City renewable and GHG-free goals, while also smoothing out purchasing over multiple years. After 2020, frequent procurements were added as needed, with the goal of managing the net short on an annual basis. The procurement target was to maintain a 1% or less variance between renewable procurement and the annual renewable targets. The table and figure show the amount of wind and solar PV capacity procured each year by case for the five cases. Cases 4 and 5 also shows the quantity of wind and solar resources procured, which are local. While the table is shown in MW, the values were calculated based on the MWh required to meet the RPS and City goals. The total capacity (MW) of wind and solar needed to supply the required energy (MWh) are affected by the capacity factor of each; they vary according to the assumed technology and location.

For all cases, the estimated procurement plan from the Net Short Model was entered into the Procurement Impact Model, and it was verified that enough purchases were made to meet annual requirements.

[18] http://www.energy.ca.gov/assessments/ab2514_energy_storage.html
[19] Batteries are generally modular so this procurement was sized to increments of 0.5MW.

Table 3-4 Procurement Plans by Case, Technology, Year, and Location (in MW)

In MW	Case 1: Balanced Procurement		Case 2: High Wind Scenario		Case 3: High Solar Scenario		Case 4: Maximize Local Scenario				Case 5: High Wind and Maximize Local Scenario			
	Wind	Solar PV	Wind	Solar PV	Wind	Solar PV	CA Wind	Local Wind	CA Solar	Local Solar	CA Wind	Local Wind	CA Solar	Local Solar
2019	50	53	76	27	20	85	50		55		76		27	
2020	95	104	149	42	40	167	63	34	70	34	107	34	20	34
2021	30	33	45	20	20	53	30		33		45		20	
2022	40	36	45	20	20	50	35		36		45		20	
2023	50	53	80	21	20	85	50		53		85		21	
2024		30	30			30	20		20		30			
2025	25		20	20		40	20				25			
2026	37		20			25	20		20		20		10	
2027		22	35		25		20				26			
2028	20	20		20		30	20		20		25		10	
2029	20		25		25				20				20	
2030	15	14	16	16		40	29				31			
TOTAL	**382**	**366**	**540**	**185**	**170**	**605**	**356**	**34**	**328**	**34**	**515**	**34**	**148**	**34**

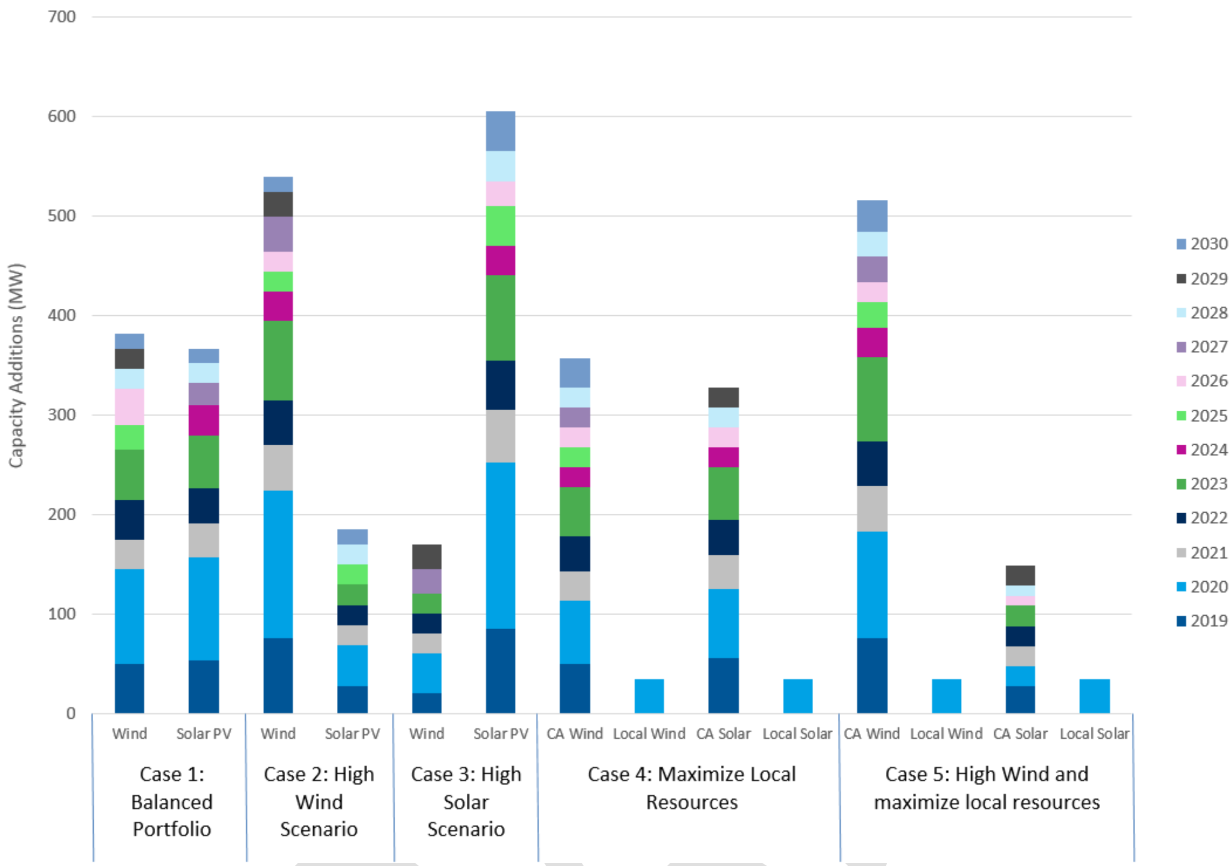

Figure 3-3 Procurement Plan Capacity Additions by Year, Case, Technology, and Location

3.2.3.4 Market Power Costs

The Black & Veatch fundamental market price forecast was developed considering the issues and perspectives facing a wide range of energy industry participants including investors, developers, lenders, utilities, and energy users; this is shown on Figure 3-4. By providing a careful consideration of the multiplicity of factors impacting today's energy markets, the Black & Veatch fundamental market price forecast uses an integrated, iterative analytical process to develop a comprehensive view of the energy industry and how it can evolve in light of multiple dynamic factors.

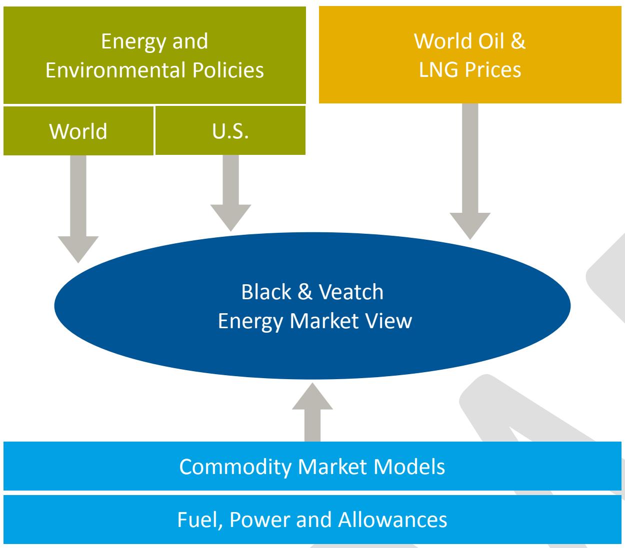

Figure 3-4 Fundamental Energy Price Forecasting

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

The combination of fundamental assumptions characterized above was used to develop the market price forecast of California and western US electricity prices. These forecast prices provide a benchmark against which to evaluate CleanPowerSF supply resource options and also a benchmark to characterize market purchase options. Figure 3-5 illustrates the forecasted energy prices for northern California. Forecasted prices follow a cyclical pattern because of seasonal demand in California; prices tend to be higher during peak summer season.

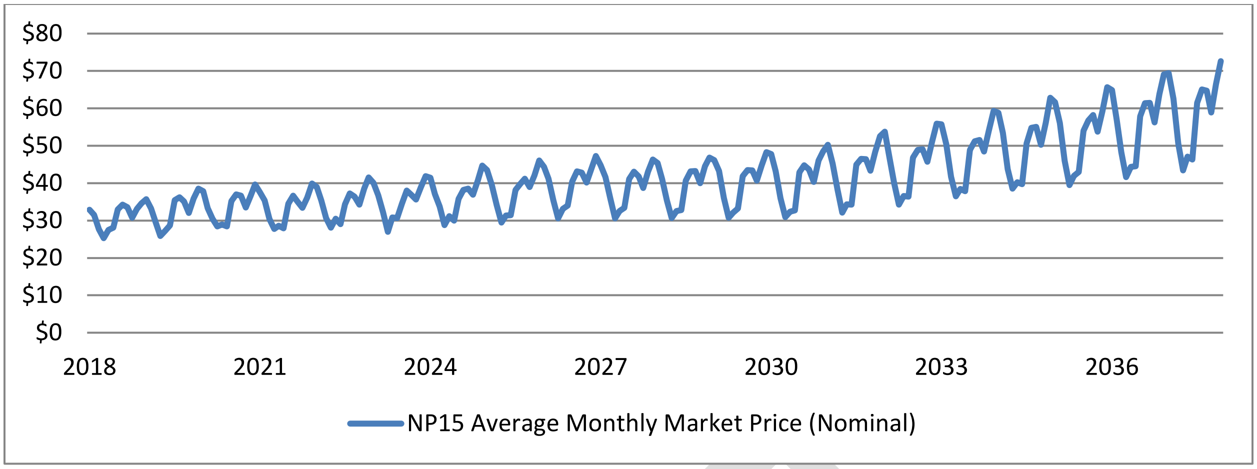

Figure 3-5 Northern California Actual and Forecasted Average Monthly Market Prices

While Black & Veatch has used all available market information to develop a reasonable projection for planning purposes, the actual prices could differ from these forecasts. Due to this uncertainty, different market prices were tested as sensitivities during the analysis.

The pricing forecasts performed by Black & Veatch reflect the impact of considerable solar PV entering the California market. As a reflection of this impact, Figure 3-6 shows the average hourly prices by month in 2030. Prices are forecasted to drop considerably during the middle of the day when solar PV generation is at its peak, then ramp in the late afternoon when load grows and solar PV generation drops off. Each line on the figure shows the different months. Figure 3-7 shows the 12 x 24 of the average hourly market price for each month of the year for 2030. These differences in monthly and hourly prices are especially important for CleanPowerSF when choosing which resources to sign up for PPAs and when to buy from the market.

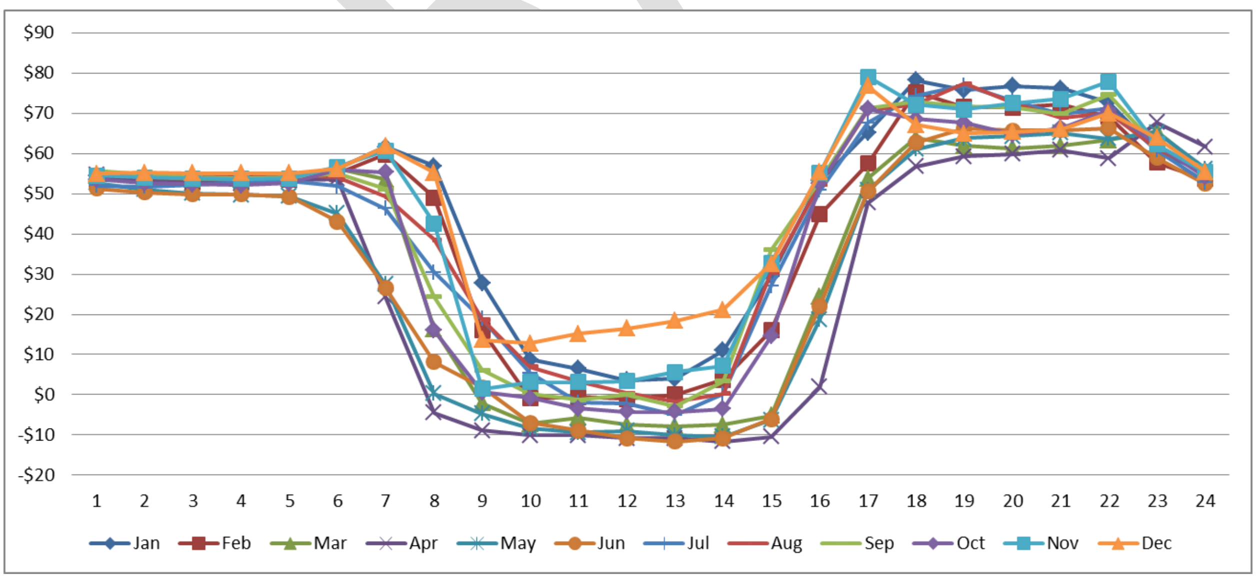

Figure 3-6 Average 2030 Hourly NP15 Market Prices, By Month

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	$54	$53	$53	$53	$53	$56	$62	$57	$28	$9	$6	$4	$4	$11	$29	$53	$65	$78	$76	$77	$76	$73	$60	$55
Feb	$54	$53	$53	$53	$54	$55	$60	$49	$16	-$1	-$1	-$1	$0	$4	$16	$45	$58	$75	$72	$71	$72	$69	$58	$54
Mar	$54	$54	$54	$53	$54	$56	$53	$16	-$2	-$7	-$6	-$7	-$8	-$7	-$5	$24	$54	$64	$62	$61	$62	$63	$66	$56
Apr	$55	$53	$53	$53	$53	$54	$24	-$4	-$9	-$10	-$10	-$11	-$11	-$12	-$10	$2	$48	$57	$59	$60	$61	$59	$68	$62
May	$53	$51	$50	$50	$49	$45	$27	$0	-$5	-$8	-$9	-$9	-$10	-$10	-$6	$19	$51	$61	$64	$64	$65	$64	$65	$56
Jun	$51	$50	$50	$50	$49	$43	$27	$8	$2	-$7	-$9	-$11	-$12	-$11	-$6	$22	$51	$63	$66	$66	$66	$66	$59	$52
Jul	$52	$52	$52	$53	$53	$52	$46	$30	$19	$5	-$2	-$2	-$5	$0	$27	$51	$68	$74	$77	$73	$70	$71	$61	$53
Aug	$55	$54	$54	$55	$55	$54	$49	$39	$19	$7	$3	$0	-$2	$0	$30	$52	$71	$72	$77	$73	$69	$70	$61	$55
Sep	$56	$55	$54	$54	$54	$55	$51	$24	$6	$0	-$1	$0	-$3	$3	$36	$53	$71	$73	$72	$71	$70	$75	$62	$56
Oct	$54	$53	$52	$52	$53	$56	$55	$16	$1	-$1	-$3	-$4	-$4	-$4	$15	$52	$71	$69	$68	$65	$66	$71	$62	$54
Nov	$55	$54	$54	$54	$54	$57	$61	$43	$1	$3	$3	$3	$6	$7	$33	$55	$79	$72	$71	$72	$74	$78	$62	$55
Dec	$55	$55	$55	$55	$55	$56	$62	$55	$14	$13	$15	$17	$18	$21	$33	$55	$77	$67	$65	$65	$66	$70	$64	$55

Figure 3-7 Average 2030 Northern CA (NP15) Market Price, 12 x 24 (Nominal $)

For analysis purposes, it is assumed that if excess power is expected to be generated in any hour, it is sold into the spot market at the wholesale market price. If power must be purchased in any hour to meet load, it was assumed to be purchased on the spot market at the wholesale market price. While CleanPowerSF will hedge its exposure to market pricing through purchases of blocks of power during certain times of the day, modeling purchases and sales in this fashion is representative of the pricing likely to be obtained.

3.2.3.5 Other Assumptions

3.2.3.5.1 Transmission

Since CleanPowerSF will need to pay similar transmission and distribution charges regardless of the resources procured, these costs were ignored as part of this analysis when the relative ranking between cases (using incremental costs) was identified. When assessing specific options as part of the procurement effort, CleanPowerSF will take into account any locality-specific congestion costs or transmission issues that may be unique to that site.

As discussed in Load Forecast assumptions, a line loss assumption of 6% was applied to CleanPowerSF's retail demand forecast.

3.2.3.5.2 Discount Rate

For the NPV incremental cost calculation, a discount rate of 5 percent was used, in line with assumptions used for the latest SFPUC IRP.

3.2.3.5.3 GHG Emissions

The model assumes that all purchases of conventional energy, and purchases on the market to supplement energy shortages with an assumed emissions rate of 0.432 metric tons/MWh; this rate is assumed constant over the study period.

4.0 Findings

4.1.1 Findings Common to All Cases

The total amount of energy procured in each of the five cases is virtually identical; minor differences are due to rounding and technical characteristics of the different technologies. For all cases, to meet the requirements laid out by the state RPS, the SuperGreen customer demand, and the City goals, minimum amounts of procurement of each type of resource are required, as shown in Table 4-1, and on Figure 4-1 and Figure 4-2. It should be noted that the state's RPS is met first, since it is a percentage of total sales. The SuperGreen bars on Figure 4-1 and Figure 4-2 denote additional purchases for ratepayers that sign up for SuperGreen 100 percent renewable energy product. The GHG-free amount is based on the city's goals, after the RPS and SuperGreen purchases are taken into account. This procurement schedule was estimated so that the amount needed in any requirement year is available no later than January 1 of that year. To achieve these requirements, CleanPowerSF will need to begin procurement before the requirement is in effect.

Table 4-1 Total Supply Recommended to Meet City Goals

	Renewable/RPS Eligible – Green Product	Renewable/RPS Eligible – SuperGreen Product	Additional GHG-Free	Conventional	Line Losses (Conventional)	TOTAL
2018	625,000	37,000	439,000	122,000	73,000	1,296,000
2019	1,369,000	58,000	1,010,000	466,000	174,000	3,077,000
2020	1,749,000	75,000	1,219,000	515,000	213,000	3,771,000
2024	2,019,000	160,000	1,145,000	306,000	218,000	3,848,000
2027	2,220,000	202,000	1,093,000	158,000	220,000	3,893,000
2030	2,447,000	233,000	1,048,000	0	224,000	3,952,000

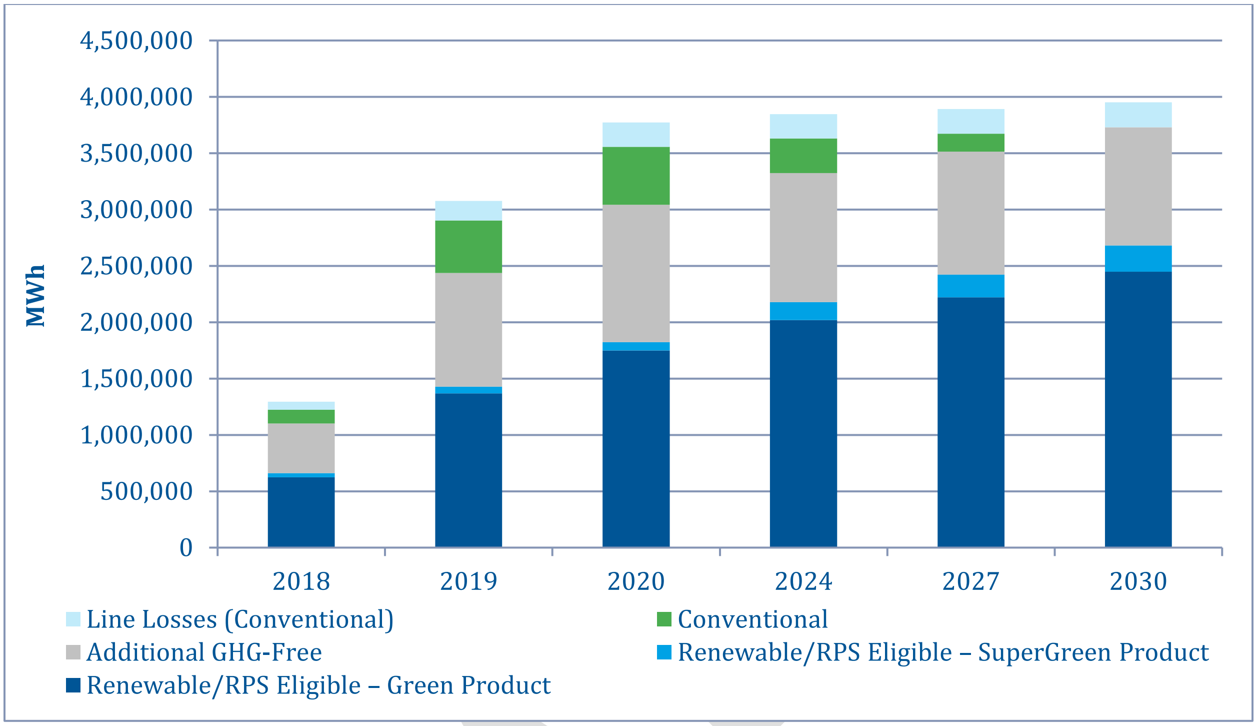

Figure 4-1 Projected CleanPowerSF Supply Types (MWh)

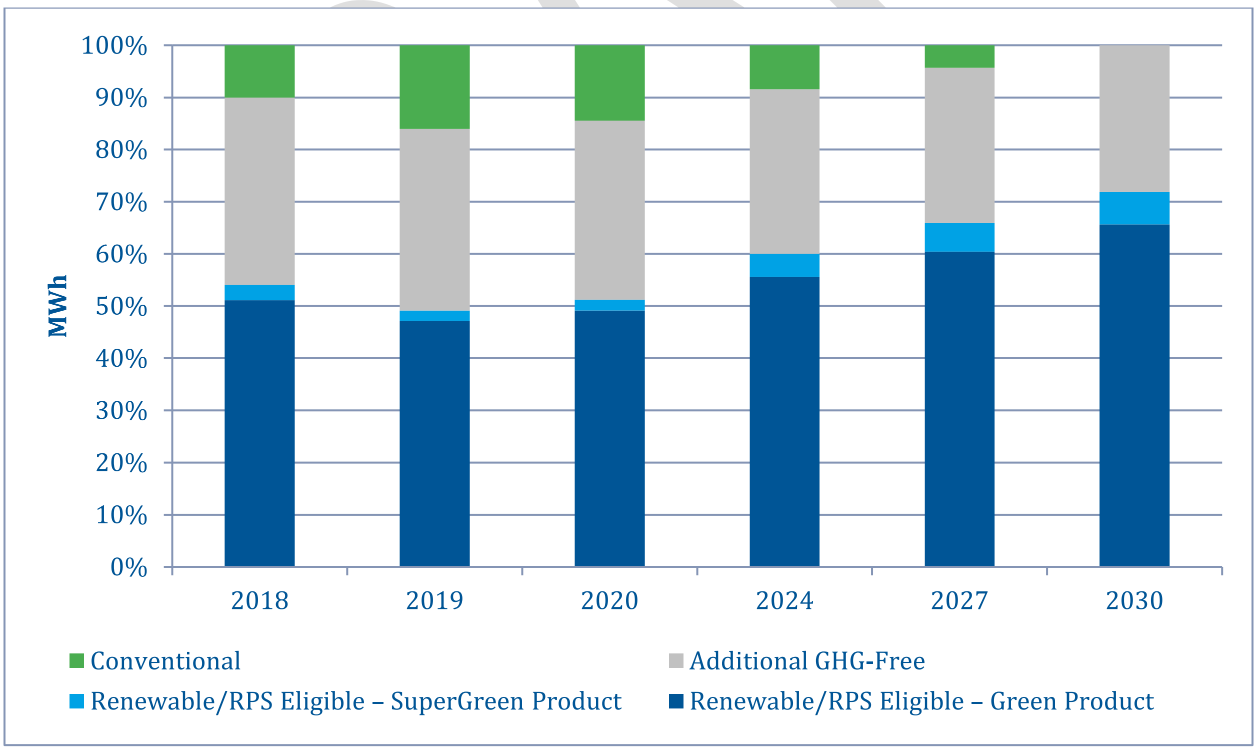

Figure 4-2 CleanPowerSF Supply Types, Percentage of Total (Excluding Line Losses)

The following sections include detailed results for each portfolio. The incremental procurement (in MWh), incremental cost, total annual purchases and sales[20], and GHG emissions are captured. The first four columns of Tables 4-2 through 4-6 also show the incremental MWh procured and NPV incremental cost that is estimated across the entire 2018-2030 period. The smaller the NPV, the less incremental money CleanPowerSF has to pay to procure resources in each case. Thus, when comparing across cases in Table 4-10, the lower dollar values should be preferred.

4.1.2 Case 1: Balanced Procurement Scenario

In the balanced procurement scenario, half of the incremental renewable energy needs (not yet contracted for at the time of this study) are provided by solar PV, and half by wind. Table 4-2 shows several results from Case 1: Balanced Procurement Scenario. First, the total incremental annual cost (above static costs that are consistent across all cases), are shown in the second column of results. The first year's annual incremental cost is significantly smaller than other years, since the CleanPowerSF program will not be fully launched until midway through 2019; this is true for all cases and can be seen in the tables for the other cases as well. The incremental NPV cost is $1.169 billion; this incremental cost will be compared to the other cases in Section 4.2.

To determine which case results in the most annual purchases of power from the wholesale market (outside of power supply contracts), the next column of Table 4-2 captures the total annual purchases. The NPV of the purchases over the 2018-2030 period is $505 million. A discussion of market strategies to procure this power and reduce the market open position can be seen in Section 4.2.

The column "Total Annual Sales" in Table 4-2 shows the total annual sales executed due to deliveries from energy supply contracts that exceed CleanPowerSF customer demand; the NPV of these sales totals $18 million. Purchases of power to meet hourly requirements are significantly greater than sales because of the procurement strategy.

Finally, the total GHG emissions of the procured energy are shown in the last column. In all five cases, emissions increase through 2020 as CleanPowerSF expands in 2018 and 2019, and then reduce to represent only the emissions from line losses in 2030 (since, as directed by the City's GHG-free goals, the City's delivered energy in 2030 is made up of 100% GHG-free content). While developing the annual procurement plan for wind and solar, the goal was to target a 1% or less variance between procurement and the annual renewable targets. The difference in GHG emissions between cases are due to minor variances between renewables procured each year (within the 1% described earlier) and the target.

[20] Total Annual Purchases and Total Annual Sales refer to market transactions conducted to net out long or short hours that results after application of the procurements shown in Table 3-4.

Table 4-2 Case 1: Balanced Portfolio Results (2018 to 2030)

	Incremental MWh	Incremental Annual Cost ($MM)	Total Annual Energy Purchases ($MM)	Total Annual Energy Sales ($MM)	GHG Emissions (metric tons)
2018	32,000	$7	$3.3	$2.7	85,000
2019	307,000	$36	$7.2	$5.3	277,000
2020	1,073,000	$66	$17.7	$5.4	315,000
2021	2,259,000	$107	$51.5	$2.1	296,000
2022	3,118,000	$139	$71.1	$0.2	261,000
2023	3,356,000	$157	$73.6	$0.3	243,000
2024	3,386,000	$164	$77.1	$0.4	226,000
2025	3,394,000	$169	$77.7	$0.5	207,000
2026	3,413,000	$174	$76.4	$0.6	175,000
2027	3,432,000	$176	$76.1	$0.8	163,000
2028	3,463,000	$180	$74.5	$1.3	129,000
2029	3,472,000	$183	$74.1	$1.3	119,000
2030	3,491,000	$187	$73.7	$1.4	96,500
NPV Cost ($MM)		**$1,169**	**$505**	**$18**	

4.1.3 Case 2: High Wind Scenario

This case utilized a much higher percentage of wind in CleanPowerSF's future portfolio: approximately 77 percent of the incremental renewable energy from wind and 23 percent from solar PV.

Table 4-3 shows several results from Case 2: High Wind Scenario. The total incremental annual cost (second column of results) show an NPV cost of $1.119 billion, or $50 million lower than Case 1. The "Total Annual Purchases" column of Table 4-3 captures the total annual purchases; the NPV cost of the purchases is $428 million, or $77 million lower than Case 1. This result is the main reason why this case has lower incremental cost than Case 1. The results are due to low PPA prices for wind and a generation profile that better matches the CleanPowerSF load, which leads to more purchases of market power when prices are lower.

Total annual sales ($22 million) are also higher than Case 1 because of the reasons previously discussed. Although less contracted power is being sold (due to a better match of generation profiles with program demand, particularly outside of the mid-day, lower market priced hours), CleanPowerSF is getting higher prices for exported power, due to the hours of the day in which overgeneration is occurring.

Table 4-3 Case 2: High Wind Scenario Results (2018 to 2030)

	Incremental MWh	Incremental Annual Cost ($MM)	Total Annual Energy Purchases ($MM)	Total Annual Energy Sales ($MM)	GHG Emissions (metric tons)
2018	32,000	$7	$3.3	$2.7	85,000
2019	307,000	$36	$6.7	$5.5	277,000
2020	1,073,000	$65	$15.4	$6.4	315,000
2021	2,259,000	$105	$47.1	$2.8	292,000
2022	3,118,000	$136	$65.4	$0.0	270,000
2023	3,356,000	$151	$64.2	$0.1	251,000
2024	3,386,000	$157	$64.2	$0.4	228,000
2025	3,394,000	$162	$64.3	$0.6	192,000
2026	3,413,000	$166	$65.0	$1.0	179,000
2027	3,432,000	$167	$60.4	$1.7	149,000
2028	3,463,000	$169	$60.5	$1.8	141,000
2029	3,472,000	$171	$59.0	$2.7	120,000
2030	3,491,000	$174	$58.1	$3.4	96,500
NPV Cost ($MM)		**$1,119**	**$428**	**$22**	

4.1.4 Case 3: High Solar Scenario

Case 3 reversed the percentage of wind and solar energy procured in Case 2; Case 3 procured approximately 77 percent of the incremental renewable energy from solar PV and 23 percent from wind.

Table 4-4 shows several results from Case 3: High Solar Scenario. The total incremental annual cost shows a NPV cost of $1.227 billion, or $58 million greater than Case 1. With a larger NPV, CleanPowerSF would pay more to procure this portfolio relative to Cases 1 and 2. The next two columns of Table 4-4 demonstrate why this case is more expensive than Cases 1 and 2. The NPV cost of market purchases is $613 million, while the total annual sales have an NPV cost of $29 million.

Table 4-4 Case 3: High Solar Scenario Results (2018 to 2030)

	Incremental MWh	Incremental Annual Cost ($MM)	Total Annual Energy Purchases ($MM)	Total Annual Energy Sales ($MM)	GHG Emissions (metric tons)
2018	32,000	$7	$3.3	$2.7	85,000
2019	307,000	$37	$8.2	$5.6	275,000
2020	1,073,000	$67	$22.9	$7.1	315,000
2021	2,259,000	$110	$56.6	$2.9	285,000
2022	3,118,000	$143	$78.7	$0.9	261,000
2023	3,356,000	$163	$85.5	$1.5	244,000
2024	3,386,000	$171	$90.0	$1.5	228,000
2025	3,394,000	$179	$93.1	$2.1	193,000
2026	3,413,000	$184	$96.6	$2.9	181,000
2027	3,432,000	$187	$94.8	$2.8	163,000
2028	3,463,000	$192	$96.9	$3.3	145,000
2029	3,472,000	$196	$96.9	$3.1	130,000
2030	3,491,000	$203	$99.0	$3.0	96,500
NPV Cost ($MM)		**$1,227**	**$613**	**$29**	

To graphically demonstrate this, Figure 4-3 shows the projected energy balance on all hours for a specific date, 1 August 2021, for Case 2 and Case 3. The energy balance is the result after the existing resources are accounted for, and the new, generic, California-based wind and solar purchases are taken into account; the remaining energy needed to meet the hourly load must be purchased from the market. In Case 2 (High Wind, blue line), market purchases are highest during the middle of the day when the market pricing (green line) is low. By comparison, Case 3 (High Solar, purple line), is actually selling power to the market during the middle of the day when pricing is low and buying power during the most expensive times of the day. In other words, in the High

Wind case (Case 2), power is being purchased when the market price is low and being sold when the market price is high. Thus, it makes sense that the total incremental annual cost of the High Wind case has a lower NPV cost than the High Solar case.

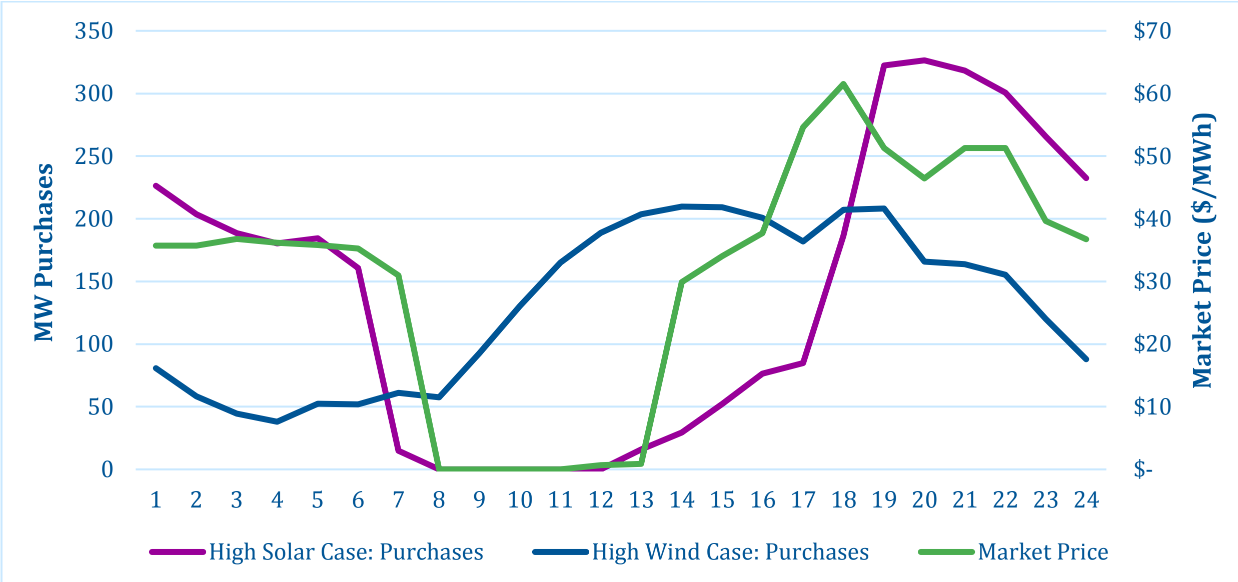

Figure 4-3 First of August 2021 Energy Balance, Case 2 and Case 3

A similar trend was found for many of the other months of the year, although it was less pronounced in the winter. In the winter, the market pricing does not drop to zero during peak solar periods, and the production from the wind facilities is flatter. For these months, the High Solar and High Wind cases economically look similar. For the rest of the months, the High Wind case looks clearly better; this is predominantly because of the projection for the hourly costs showing zero pricing for more months of the year than what is seen today. Even if this level of zero pricing does not come to fruition, the winter price results demonstrate that, at worst, a high wind procurement strategy would be break even with a more solar heavy portfolio.

4.1.5 Case 4: Maximize Local Resources Scenario

The split of resources utilized for Case 4 was similar to that of Case 1 and, thus, balanced the procurement of solar and wind: half of each was provided to meet generation requirements. As previously discussed, 33.7 MW of solar PV in this case is from four Bay Area locations on land owned by the SFPUC, while 33.7 MW of wind was from a repowered Altamont Pass wind project. While larger amounts of local resources could potentially be procured, the intent of this analysis was to demonstrate the incremental costs and economic outcome associated with procurement of resources likely to be most readily available to CleanPowerSF. Procuring different resources in the Bay Area would require a more detailed, site-specific cost and performance estimate.

Table 4-5 shows several results from Case 4: Maximize Local Resources. The total incremental annual cost shows an NPV cost similar to that of Case 1. The reasons for this is the relative cost of the procured local resources when compared to Case 1. The local solar resources are more expensive ($45/MWh in 2020 compared to $34/MWh for other solar options on a cumulative weighted average) because of size, labor costs, and lower output than the Central Valley projects. Local Altamont Pass wind has a slightly higher PPA price than the other wind resources in Case 1. So it does not displace other wind resources, but is competitive. Since the total local procurement is only a total of 67MW, this case has only a slightly higher NPV than Case 1.

Table 4-5 Case 4: Maximize Local Resources, Balanced Solar-Wind Results (2018 to 2030)

	Incremental MWh	Incremental Annual Cost ($MM)	Total Annual Energy Purchases ($MM)	Total Annual Energy Sales ($MM)	GHG Emissions (metric tons)
2018	32,000	$7	$3.3	$2.7	85,000
2019	307,000	$36	$7.2	$5.4	274,000
2020	1,073,000	$67	$17.6	$5.2	315,000
2021	2,259,000	$109	$51.5	$2.0	297,000
2022	3,118,000	$141	$71.8	$0.1	269,000
2023	3,356,000	$158	$74.3	$0.3	251,000
2024	3,386,000	$166	$75.5	$0.4	218,000
2025	3,394,000	$170	$76.9	$0.3	208,000
2026	3,413,000	$176	$76.7	$0.6	170,000
2027	3,432,000	$177	$74.7	$0.7	161,000
2028	3,463,000	$181	$72.9	$1.1	127,000
2029	3,472,000	$185	$74.7	$1.2	117,000
2030	3,491,000	$188	$72.9	$1.2	96,500
NPV Cost ($MM)		**$1,179**	**$503**	**$17**	

4.1.6 Case 5: Maximize Local Resources with High Wind Scenario

After identification of Case 2's High Wind case as a lower-cost option to meet the CleanPowerSF's renewable targets (and comply with RPS requirements), a new Case, Case 5, was developed to combine Case 2 (77% of renewable net short filled with wind, and 23% with solar PV) with local procurement. As in Case 4, 33.7 MW of solar PV in this case is from four Bay Area locations on land owned by the SFPUC, while 33.7 MW of wind was from a repowered Altamont Pass wind project. While larger amounts of local resources could potentially be procured, the intent of this analysis was to demonstrate the incremental costs and economic outcome associated with procurement of resources likely to be most readily available to CleanPowerSF. Procuring different resources in the Bay Area would require a more detailed, site-specific cost and performance estimate.

Table 4-5 shows several results from Case 5: Maximize Local Resources, High Wind. The total incremental annual cost shows an NPV cost of $1.131 billion; this is $12 million greater than Case 2, but $48 million less than Case 4. Total Annual Energy Purchases in NPV for the 2018-2030 period are $429 million, and annual sales are $21 million.

Table 4-6 Case 5: Maximize Local Resources, High-Wind Results (2018 to 2030)

	Incremental MWh	Incremental Annual Cost ($MM)	Total Annual Energy Purchases ($MM)	Total Annual Energy Sales ($MM)	GHG Emissions (metric tons)
2018	32,000	$7	$3.3	$2.7	85,000
2019	307,000	$36	$6.7	$5.5	276,000
2020	1,073,000	$66	$15.5	$5.9	316,000
2021	2,259,000	$107	$47.6	$2.7	294,000
2022	3,118,000	$138	$66.1	$0.0	272,000
2023	3,356,000	$153	$64.4	$0.1	247,000
2024	3,386,000	$159	$64.4	$0.3	224,000
2025	3,394,000	$163	$64.8	$0.5	206,000
2026	3,413,000	$168	$65.1	$0.9	181,000
2027	3,432,000	$168	$61.5	$1.4	163,000
2028	3,463,000	$170	$59.0	$2.3	132,000
2029	3,472,000	$173	$59.7	$2.4	121,000
2030	3,491,000	$176	$57.6	$3.5	96,500
NPV Cost ($MM)		**$1,131**	**$429**	**$21**	

4.1.7 Sensitivity 1: Low and High Market Price

Error! Reference source not found. shows the impact of high and low wholesale energy market prices for all fives cases. As described in Subsection 3.2.2, the average of the hourly energy market price for the low incremental cost case is approximately 10 percent lower than the base forecast, and the average of the hourly energy market prices for the high incremental cost case is approximately 20 percent higher.

As can be seen on the table, the high wind case has the lowest NPV cost in all instances, since the incremental costs for most hours of the year are adjusting up (high market price) or down (low) by a similar amount. However, if the spread of pricing between peak and off-peak periods was to change significantly, the ranking between cases would be affected.

Table 4-7 Low and High Market Price Incremental NPV Cost Results (2018 to 2030)

	Case 1: Balanced Procurement ($MM)	Case 2: High Wind Scenario ($MM)	Case 3: High Solar Scenario ($MM)	Case 4: Maximize Local Scenario ($MM)	Case 5: High Wind and Maximize Local Scenario ($MM)
Low Market Price	$1,123	$1,073	$1,181	$1,133	$1,085
Base Market Price	$1,169	$1,119	$1,227	$1,179	$1,131
High Market Price	$1,341	$1,292	$1,399	$1,351	$1,304

Notes:
The changes in the market pricing impacts the cases similarly; the high market price case is 115% of the base market price case and the low market price case is 96% of the base market price case

4.1.8 Sensitivity 2: Investment Tax Credit Extension

Table 4-8 shows the difference between the current ITC, where it ramps down from 30 percent in 2019 to 10 percent in 2022, and the ITC extension case, where the ITC is assumed to hold at 30 percent through 2030. As shown, the impact is minimal – between 1 to 3 percent (depending on the Case) on an NPV cost basis. This result shows that the projected improvements in technology performance and incremental cost reductions will make up for the reduction of the ITC to 10 percent starting in 2022. This means that the ITC becomes less important as the technology improvements increase performance and the cost improvements decrease costs. It also indicates that it is a low-risk proposition to procure more capacity and power in the near-term, instead of waiting for the longer term.

Table 4-8 Impact of a 30 Percent ITC Extension Through 2030 (2018 to 2030)

	Case 1: Balanced Procurement ($MM)	Case 2: High Wind Scenario ($MM)	Case 3: High Solar Scenario ($MM)	Case 4: Maximize Local Scenario ($MM)	Case 5: High Wind and Maximize Local Scenario ($MM)
Current ITC Schedule	$1,169	$1,119	$1,227	$1,179	$1,131
ITC Extension through 2030	$1,145	$1,108	$1,188	$1,156	$1,122

Change %	-2%	-1%	-3%	-2%	-1%

4.1.9 Sensitivity 3: Higher Altamont Wind Costs

As shown in Table 4-9, increasing the expected technology cost of Altamont wind projects by 10 percent shows a $4 million incremental change from the base case assumptions, or a 0.3 percent difference. This relatively small shift is not surprising since the Altamont project is 33.7 MW and the total wind additions is 390 MW in Case 4 and 549 MW in Case 5. The Altamont wind resource is only a small portion of the total incremental costs, and changing the technology costs for that one project would not affect the total costs for the planning horizon by a substantial amount.

Table 4-9 Incremental NPV Cost Impact of Adjusted Altamont Wind Pricing (2018 to 2030)

	Case 4: Maximize Local Scenario ($MM)	Case 5: High Wind and Maximize Local Scenario ($MM)
Current Altamont Pricing	$1,179	$1,131
Revised Altamont Cost	$1,183	$1,135
Change %	0.3%	0.3%

4.1 Selected Portfolio

4.1.1 Summary of Results and Selected Portfolio

Reflecting upon the five cases under investigation, it is clear that Case 2 (High Wind) is lowest cost. As shown in Table 4-10, the incremental cost to CleanPowerSF is lowest for Case 2, where most of the renewable energy procured is wind. This is due to projected low cost PPAs, a resource portfolio best meeting the expected load profile of CleanPowerSF, and expected market power expenditures lowest because of purchases occurring during lower cost period times relative to other portfolios.

Taking into consideration CleanPowerSF's core program goal to engage in local development, Case 5, which combines Case 2's high level of wind energy with local procurement, may be the preferred portfolio for planning purposes.

Table 4-10 Comparison of Results for Study Period Duration (2018-2037)

	Incremental Annual NPV Cost ($MM)	Total Annual Energy Purchases ($MM)	Total Annual Energy Sales ($MM)
Case 1: Balanced Procurement	$1,169	$505	$18
Case 2: High Wind Scenario	$1,119	$428	$22
Case 3: High Solar Scenario	$1,227	$613	$29

Case 4: Maximize Local Scenario	$1,179	$503	$17
Case 5: High Wind and Maximize Local Scenario	$1,131	$429	$21

When current and predicted market conditions are considered in more detail, moving toward higher wind procurement makes sense for several reasons. Figure 4-4 shows the average California wholesale market prices for the NP-15 zone on a 12 month by 24 hour basis (12 x 24). The 12 x 24 graphically depicts low market prices (red) and high market prices (green). As shown, during the middle of the day when solar is peaking, wholesale market prices are low, and even go to zero or negative, depending on the month and year. Therefore, the system already has a large amount of solar PV, and incremental solar PV sales from excess production during the middle of the day will not generate much additional revenue. Likewise, adding solar PV will offset midday purchases of market power; however, that is when the price is lowest because of oversupply. Instead, it makes sense to purchase wholesale power when it is least expensive, during the middle of the day, and to offset the more expensive power in the evening hours.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	38	38	38	38	38	39	42	41	33	27	25	24	24	26	32	39	43	55	60	58	53	47	41	39
Feb	38	38	38	38	38	39	42	39	28	15	13	11	10	15	21	36	40	52	61	59	55	46	40	38
Mar	38	38	37	37	37	38	39	28	5	2	1	1	0	4	14	32	39	50	57	57	55	49	40	37
Apr	38	39	38	38	39	39	35	11	(1)	(5)	(8)	(8)	(6)	(0)	7	30	39	50	54	56	56	54	42	38
May	38	37	36	36	36	34	31	20	1	1	2	(0)	1	7	23	36	40	53	57	56	58	54	41	37
Jun	37	36	35	35	35	33	28	15	1	1	1	0	2	7	18	35	39	49	57	54	55	50	39	37
Jul	36	36	36	36	36	35	34	25	15	13	14	10	15	25	34	37	39	55	66	53	52	48	37	36
Aug	37	37	37	37	37	37	36	29	18	15	21	23	27	31	36	39	42	57	62	56	55	47	39	38
Sep	39	39	39	39	39	39	38	24	6	6	7	12	20	30	37	41	51	60	59	59	58	49	41	40
Oct	39	39	39	39	39	40	40	23	5	2	3	4	9	14	34	40	49	56	60	61	58	50	42	39
Nov	39	39	39	39	39	40	43	38	18	15	13	13	15	26	37	41	48	64	65	63	58	49	41	40
Dec	40	40	40	40	40	41	43	42	32	29	28	27	28	31	38	42	46	58	61	60	58	50	42	41

Figure 4-4 Average California NP-15 Wholesale Market Prices in 2022 (Nominal dollars)

Figure 4-5 shows the average hourly wholesale market energy purchases for the high wind case. The highest amounts of wholesale purchases are shown in green, and the lowest are shown in red. When Figure 4-4 and Figure 4-5 are compared, the lack of correlation between when energy purchases are made (during the middle of the day) and high market prices (early evening hours, especially during the summer) is clear. While market purchases during early evening hours in the winter time when prices are high is necessary, this is true for all portfolios examined. The key benefit of the high wind case is the ability to buy low priced power in the middle of the day and avoid buying expensive early evening power in the summer.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	260	244	238	240	252	278	327	340	283	295	311	313	302	295	286	295	373	437	435	418	400	369	324	280
Feb	238	229	225	226	239	269	318	302	260	280	296	300	296	291	279	274	319	395	417	403	378	342	303	264
Mar	181	166	157	159	166	193	211	168	173	182	196	200	198	192	180	173	199	266	274	284	284	261	226	195
Apr	140	129	127	131	142	161	145	142	162	181	201	209	208	202	190	169	163	219	225	221	235	212	181	154
May	77	64	60	63	74	73	52	71	101	130	154	165	163	158	143	118	102	139	180	158	167	151	120	93
Jun	62	52	46	45	56	47	34	60	99	137	171	187	193	194	178	149	125	137	191	167	152	141	104	78
Jul	27	18	17	20	31	38	38	61	97	136	173	193	198	195	181	157	134	139	167	133	116	100	71	47
Aug	65	53	50	55	68	84	68	83	129	171	211	236	248	251	239	219	203	228	219	179	172	148	114	87
Sep	119	112	110	117	135	165	150	121	161	199	232	258	272	283	277	267	281	316	260	240	223	195	165	139
Oct	168	158	154	154	166	192	205	148	164	200	230	247	253	255	249	256	327	341	308	300	283	254	220	188
Nov	232	217	211	215	230	260	295	248	224	260	285	293	289	282	277	302	392	423	406	386	365	331	293	259
Dec	228	214	208	205	216	243	286	293	246	261	281	283	277	274	265	285	362	401	383	364	348	322	289	254

Figure 4-5 Average Hourly Energy Purchases (MW) for High Wind Case in 2022

Using the average hourly energy purchases on Figure 4-5, an estimate of the block market purchase opportunities needed to meet the remaining needs is shown in Table 4-11. Block purchase estimates were based on the minimum requirements and were broken out into four categories: (1) 24 x 7 block purchases, (2) superpeak purchases (1:00 p.m. to 8:59 p.m. for June to August), (3) on-peak purchases (7:00 a.m. to 10:59 p.m.), and (4) off-peak purchases (1:00 a.m. to 6:59 a.m. and 11:00 p.m. to 12:59 a.m.). The amount of 24 x 7 block purchases needed was estimated for the smallest average wholesale energy purchase across all hours in that month. For example, January 24 x 7 block purchases were based on the minimum amount of 238 in Hour 3. From these, the minimums were subtracted from the average hourly energy purchases on Figure 4-5 to identify the residual amount of energy needs. From that residual amount, the superpeak purchases and on-peak purchases estimates were based on the remaining minimums during the appropriate hours and months. After these were subtracted from the residual amount, the average minimum in each month was zero as shown – meaning that no specific off-peak purchases would be recommended.

This analysis was based on generic solar and wind projects in a variety of California locations and, thus, are indicative. To determine the actual block market purchases that would be required, additional analysis is needed. Once actual wind and solar projects are identified and procured, the block market purchase analysis should be rerun using the expected production of those project resources and expected production. There will be differences between the indicative estimates in Table 4-11 and the actual production needed to meet load because the actual resources will differ.

Table 4-11 2022 High Wind Case Block Market Purchases: Potential Opportunities (MW)

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
24x7 Block	238	225	157	127	52	34	17	50	110	148	211	205
Superpeak						92	116	130				
On Peak	45	36	11	15	0	0	21	18	12	0	13	41
Off Peak	0	0	0	0	9	11	0	0	0	6	0	0

With regard to the length of contracts recommended for near-term projects, the projected ramp down of the federal tax credits, coupled with the sensitivity analysis about the impact of market pricing in the CleanPowerSF portfolio, appears to make locking in wind PPAs for an extended period of time low risk. Even if load projections vary relative to this IRP, the profile and technology cost of the wind resources would likely be attractive to others in the market.

4.1.2 Jobs and Local Impacts

A high-level estimate of jobs and local impacts from the five main cases was developed. To estimate the impact, the number of jobs created by wind and solar PV projects as estimated by the International Renewable Energy Agency (IRENA) from a 2013 Renewable Energy Jobs report (which applies US-specific factors as developed by the National Renewable Energy Laboratory) was applied.[21] IRENA estimates management, construction, and installation (MCI) jobs as well as operations and maintenance (O&M) jobs for both land-based wind and solar PV, as shown in Table 4-12. It should be noted that this does not reflect new or permanent job creation, but simply an estimate of the staff that would be employed for a project.

Table 4-12 IRENA Renewable Energy Jobs Estimates per MW

	MANAGEMENT, CONSTRUCTION, AND INSTALLATION (JOBS / MW)	OPERATIONS & MAINTENANCE (JOBS / MW)
Land-Based Wind	12.1	0.1
Solar PV	20.0	0.2
Source: IRENA 2013 Renewable Energy Jobs report.		

The IRENA figures were used to estimate the annual jobs impact for the five main cases examined, on the basis of total capacity installment estimates. It was assumed that, on average, it takes 1 year to install the total amount of solar PV and wind in each year, and that MCI will be performed in the year before the capacity and generation are needed to meet requirements. Each year of the study, the previous years' cumulative wind and solar projects are operated and maintained throughout the analysis period.

Table 4-13 shows a high-level estimate of the annual jobs that each case could create, according to the IRENA estimates and indicative capacity estimates found in Table 4-2, Table 4-3, Table 4-4, Table 4-5, and Table 4-6. As shown, the High Solar scenario has the highest estimated annual job creation; both MCI and O&M jobs are higher for solar than for wind. Cases 4 and 5 includes an estimate of local resources on the basis of the number of local wind and solar capacity installed in 2020 and maintained every subsequent year.

[21] "Renewable Energy and Jobs," (2013), International Renewable Energy Agency, Table 2.2, http://www.irena.org/rejobs.pdf.

Table 4-13 High Level Annual Jobs Estimate, by Case

	Case 1: Balanced Procurement			Case 2: High Wind Scenario			Case 3: High Solar Scenario			Case 4: Maximize Local Resources					Case 5: High wind and Maximize Local Resources				
	Wind	Solar PV	TOTAL	Wind	Solar PV	TOTAL	Wind	Solar PV	TOTAL	CA Wind	Local Wind	CA Solar	Local Solar	TOTAL	CA Wind	Local Wind	CA Solar	Local Solar	TOTAL
2018	605	1,061	1,666	916	540	1,456	242	1,698	1,940	605		1,100		1,705	920		540		1,460
2019	1,155	2,094	3,248	1,806	839	2,645	486	3,350	3,836	767	408	1,420	674	3,269	1,302	408	405	674	2,789
2020	375	699	1,074	567	414	981	248	1,119	1,367	372	3	693	7	1,075	563	3	409	7	982
2021	501	754	1,255	571	418	989	250	1,061	1,311	438	3	747	7	1,195	567	3	413	7	991
2022	626	1,110	1,736	999	448	1,447	252	1,774	2,026	623	3	1,104	7	1,736	1,056	3	437	7	1,503
2023	26	656	682	402	26	428	12	688	700	265	3	450	7	724	399	3	22	7	431
2024	329	62	391	284	426	710	12	894	906	267	3	54	7	330	341	3	22	7	373
2025	477	62	539	286	30	316	12	602	614	269	3	454	7	732	283	3	222	7	515
2026	33	502	535	470	30	500	315	107	422	271	3	58	7	338	358	3	24	7	392
2027	275	466	741	50	430	480	15	707	722	273	3	458	7	740	348	3	224	7	582
2028	277	70	347	352	34	386	317	113	430	33	3	462	7	504	48	3	426	7	484
2029	218	356	575	240	344	584	17	909	926	380	3	66	7	456	427	3	30	7	467
2030	38	73	111	54	37	91	17	121	138	36	3	66	7	111	52	3	30	7	91

4.1.3 Distributed Energy Resources

The load forecast for CleanPowerSF developed by the SFPUC includes the initial views for the expected load at full buildout, taking into account statewide forecasted impacts of DERs such as customer-sided solar PV, EVs, EE, and customer-sided ES. After CleanPowerSF reaches full capacity, a better understanding of the actual load and the impacts of DERs on the CleanPowerSF system will be able to be refined for future IRPs. In addition, more detailed analysis on the likely impacts of DERs in San Francisco relative to the CleanPowerSF load can be performed at that time.

Future approaches and program opportunities that may be undertaken by CleanPowerSF in the future include the following:

- **Energy Efficiency:** Consistent with direction provided by the CPUC for IRP forecasting, load growth projections developed by CleanPowerSF utilize future growth forecasts developed in the CEC IEPR and take into account the mid AAEE estimates. As of the development of this IRP, the CEC is still working to determine what level, if any, of additional EE savings should be taken into account by LSEs to meet the Clean Energy and Pollution Reduction Act (SB 350) targets. When this becomes finalized, CleanPowerSF will review these goals and determine the appropriate targets to include in the IRP and what programs should be considered to help meet these goals. While CleanPowerSF does not currently administer an EE program using CPUC funds for benefit of its customers, this arrangement will be evaluated in the future.

- **Solar PV:** Past work performed by Black & Veatch estimates that an achievable goal for citywide rooftop solar in San Francisco would be in the 50 to 70 MW range. Data from the GoSolarSF program shows that San Francisco is well on its way to achieving this goal, with roughly 40 MW installed through mid-2017. CleanPowerSF also has the NEM program, as described in Subsection 2.2.3. The past analysis for achievable potential did not take into account the emergence of the CCA and how new rate structures may impact local consumer's choice to install solar. Data from the GoSolarSF program that is administered by the CPUC provides insight into current consumer behavior, given the current rate and incentive structure. Now that the CCA has begun in San Francisco, existing programs could be modified or additional programs could be rolled out (for example, a community solar program could provide options for residents who may not be able to install solar themselves); the goal would be to provide additional incentives for customer-supported solar. As decisions are made on these types of programs, the load forecast will be modified to reflect the likely impacts.

- **Electric Vehicles:** The current penetration of EVs is taken into account in the current load forecast, and as more EVs are seen in the CleanPowerSF service territory, both the total amount of electric demand and the shape of the demand profile will be affected. Because of current uncertainties about the impact on the overall load, a detailed investigation has yet to be performed. In general, more EVs in San Francisco will increase load largely during the nighttime, which will be consistent with a procurement approach that stresses wind over solar. As more data are gathered on customer EV adoption as CleanPowerSF completes its full customer rollout, this information will be incorporated into future forecasts.

  CleanPowerSF will have the option in the future of providing customer incentives for the use of EVs if deemed useful to help meet City goals. Sonoma Clean Power has seen positive feedback from its recent pilot programs to support EV usage by reducing barriers due to financing and overall cost. The applicability and need for a program of this nature should be considered as San Francisco continues in the future toward its GHG and renewable energy goals.

- **Customer-Sided Storage:** Currently, customer-sided storage is limited and has little impact on net load because of the high capital cost. Given the low cost of market-based capacity and ancillary services to provide the benefits that storage can bring to CleanPowerSF, there is likely to be limited value to incentivizing customer-sided storage. However, customers will be adopting storage regardless of the actions of CleanPowerSF; the levels and impacts should be reviewed to determine the level that should be appropriately modeled in the load forecast.

5.0 Next Steps

On the basis of the analysis performed in the previous section, key proposed activities to be undertaken by CleanPowerSF include the following.

1. **Establish a regular and transparent procurement cycle to meet City and State electricity resource requirements and goals.** CleanPowerSF should implement regular power solicitation cycles so that it can continue to procure the energy and capacity it needs to meet its power content and reliability requirements and goals through 2030.
2. **Develop a portfolio featuring a technologically and geographically diverse mix of renewable resources, while prioritizing investment within the Greater Bay Area, to the extent technically and economically feasible.** CleanPowerSF's IRP analysis has shown that a mix of wind and solar resources is cost-effective. CleanPowerSF will consider these findings (balancing them with program goals such as job creation and local

investment) as it continues to procure a diverse and reliable portfolio for its customers, and will review how these findings may change with developments in technology (e.g., increased affordability of energy storage) and evolving market costs.

3. **Procure energy from local wind resources as available and cost-effective.** From analysis performed as part of this IRP and expectations by Black & Veatch, local Altamont Pass wind resources appear to be cost competitive with other statewide options. CleanPowerSF should look to procure these resources where available because of their cost and alignment with the goals of CleanPowerSF to support local projects.
4. **Lock in near-term pricing for renewable resources.** On the basis of the PPA prices received in the most recent Request for Proposal, the results of the market price analysis, and projections for changes in federal incentives, locking in near-term pricing for an extended contract period makes economic sense. The benefits of these prices should be weighed against other risk factors facing CleanPowerSF, such as opt-out rates and regulatory changes.
5. **Active portfolio management to stay competitive in a rapidly evolving energy market.** As California moves toward 50% renewable energy by 2030 – and as some load-serving entities, such as CleanPowerSF, set goals to get there even sooner – we face a rapidly-changing set of procurement opportunities. New renewable generation, breakthroughs in renewable technology, and shifting CAISO market costs all may shift where the best procurement opportunities lie for pursuit of CleanPowerSF's program goals. CleanPowerSF will continue its practice of active portfolio management and regular market review to mitigate risks and review new opportunities.

Appendix A. CleanPowerSF's Integrated Resource Plan Compliance Filing