Attachment C

Technical Study for Community Choice Aggregation Program in Alameda County

Appendices

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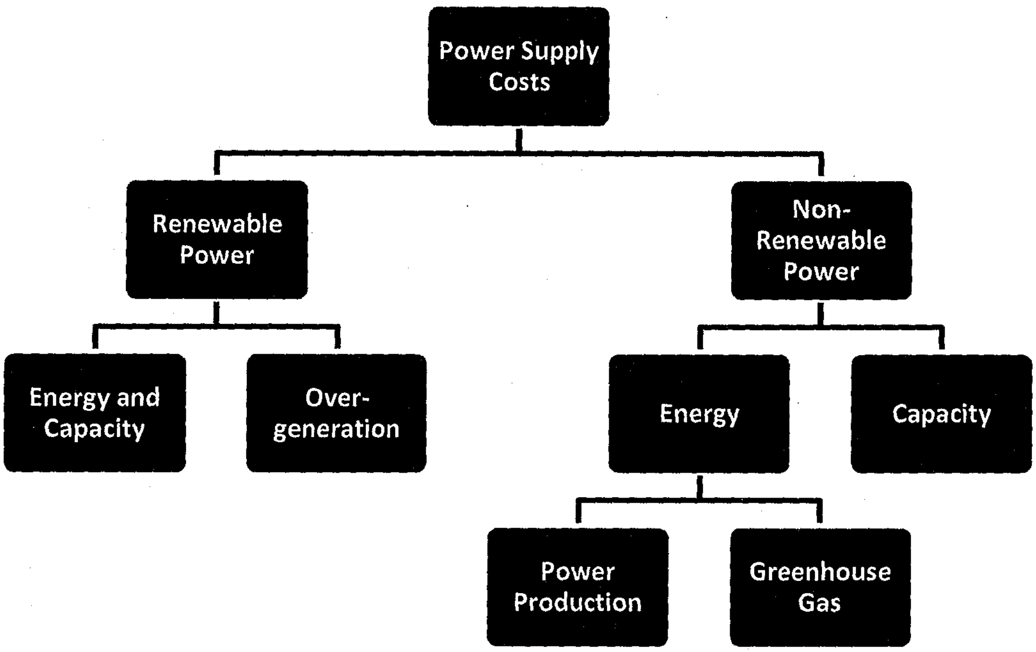
Appendix A. Loads and Forecast

2014 Load (MWh)	Residential	Commercial	Industrial	Public	Street lights + Pumping
OAKLAND	660,782	741,932	415,045	167,285	20,345
FREMONT	392,214	676,908	185,178	47,987	4,427
HAYWARD	240,909	444,599	71,270	30,672	25,598
BERKELEY	159,531	206,825	86,752	227,612	3,734
PLEASANTON	185,564	272,979	42,262	22,162	6,147
SAN LEANDRO	155,124	228,047	91,569	38,709	3,381
UNINCORPORATED	271,869	123,148	82,804	31,308	4,788
LIVERMORE	211,533	236,038	26,615	23,171	862
UNION CITY	114,258	175,482	6,194	54,684	5,401
DUBLIN	113,425	129,981	26,134	25,465	2,214
NEWARK	75,030	144,879	21,720	15,670	1,421
EMERYVILLE	21,608	132,815	44,507	3,637	1,024
ALBANY	23,494	13,997	15,602	2,855	1,778
PIEDMONT	27,774	1,622	0	3,044	328

Appendix B. Power Supply Cost

MRW has developed a bottoms-up calculation of Alameda CCA's power supply costs, separately forecasting the cost of each power supply element. These elements are renewable energy, non-renewable energy (including power production costs and greenhouse gas costs), resource adequacy (RA) capacity (both renewable and non-renewable supplies) and related costs (e.g., CAISO expenses and broker fees).[1] Figure 1 illustrates the components of Alameda CCA's expected supply costs.

Figure 1: Power Supply Cost Forecast



Renewable Power Cost Forecast

MRW developed a forecast of renewable generation prices starting from an assessment of the current market price for renewable power. For the current market price, MRW relied on wind and solar contract prices reported by California municipal utilities and Community Choice Aggregation (CCA) entities in 2015 and early 2016, finding an average price of $52 per MWh for these contracts.[2]

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[1] MRW included a 5.5% adder in the power supply cost for CAISO costs (ancillary services, etc.), and a 5% premium for contracted supplies to reflect broker fees and similar expenses.

[2] MRW relied exclusively on prices from municipal utilities and CCAs because investor-owned utility contract prices from this period are not yet public. We included all reported wind and solar power purchase agreements, excluding local builds (which generally come at a price premium), as reported in California Energy Markets, an

To forecast the future price of renewable purchases, MRW considered a number of factors:

- Researchers from the National Renewable Energy Laboratory (NREL) and Lawrence Berkeley National Laboratory (LBNL) developed a set of forecasts of utility-scale solar costs based on market data and preliminary data from other research efforts.[3] Their base case forecast predicts a 3.8% annual decline in utility-scale solar capital costs on a nominal basis, from $1,932/kW-DC in 2016 to $1,652/kW-DC in 2020, with costs then remaining roughly constant in nominal dollars through 2030.[4] Additional scenarios predict even steeper price declines, with the most aggressive scenario predicting an 11% annual nominal decline through 2020, with increases at the rate of inflation after that.
- The federal Investment Tax Credit (ITC), which is commonly used by solar developers, is scheduled to remain at its current level of 30% through 2019 and then to fall over three years to 10%, where it is to remain.[5] The federal Production Tax Credit, which is commonly used by wind developers, is scheduled to be reduced for facilities commencing construction in 2017-2019 and eliminated for subsequent construction.[6] The loss of these credits would put upward pressure on prices.
- NREL and LBNL researchers predicted in 2015 that the cost increase associated with an ITC reduction would be roughly offset by other solar cost reductions even if the full reduction to 10% were to be implemented by 2018, rather than spread out through 2022 as is currently planned.[7]
- The production tax credit has been extended six times from 2000-2014,[8] and the solar ITC has been extended three times since 2007.[9] Further tax credit extensions are therefore plausible.
- The major California investor-owned utilities have significantly slowed their renewable procurement because lower-than-expected customer sales and higher-than-expected contracting success rates have led to procurement in excess of the RPS requirements

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independent news service from Energy Newsdata, from January 2015-January 2016 (see issues dated July 31, August 14, October 16, October 30, 2015, and January 15, 2016).

[3] National Renewable Energy Laboratory. Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions, September 28, 2015, Slide 16. http://www.nrel.gov/docs/fy16osti/65014.pdf

[4] Ibid. Costs converted to nominal dollars using the inflation forecast used throughout the rate forecast model (U.S. EIA's forecast of the Gross Domestic Product Implicit Price Deflator).

[5] U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). http://energy.gov/savings/business-energy-investment-tax-credit-itc

[6] U.S. Department of Energy. Electricity Production Tax Credit (PTC). http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc

[7] National Renewable Energy Laboratory. Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions, September 28, 2015, Slide 28.

[8] Union of Concerned Scientists. Production Tax Credit for Renewable Energy. http://www.ucsusa.org/clean_energy/smart-energy-solutions/increase-renewables/production-tax-credit-for.html

[9] Solar Energy Industries Association. Solar Investment Tax Credit. http://www.seia.org/policy/finance-tax/solar-investment-tax-credit; and U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). http://energy.gov/savings/business-energy-investment-tax-credit-itc

through 2020. When the utilities start ramping their procurement back up to meet the 50%-by-2030 RPS requirement, the supply-demand balance in the market may shift, resulting in higher-than-expected prices unless an increase in suppliers and development opportunities matches the increase in demand.

Given the potential upward price pressures from tax credits that are currently expected to expire and from higher demand for renewable power to meet the 50%-by-2030 requirement and the potential downward price pressures from falling renewable development costs, the possibility for lower cost procurement through the use of RECs, and the possibility that the expiry of the tax credits will be further delayed, it is unclear whether renewable prices will continue to fall (as NREL, LBNL, and others are predicting) or will start to stabilize and rise. MRW has addressed this uncertainty by considering two scenarios. In the base renewable cost forecast, MRW used the $52 per MWh average price of recent municipal utility and CCA wind and solar contracts as the price through 2022 (in nominal dollars), increasing the price with inflation in subsequent years. This results in a price of $59 per MWh in 2030. In the high renewable cost scenario, MRW increased the base case renewable prices to account for the expected expiration of the tax credits, resulting in a price of $77 per MWh in 2030. These scenarios provide a reasonable window of renewable price projections based on current market conditions and analysts' expectations.

MRW used these same renewable prices to calculate PG&E's renewable power costs. However, as described in Appendix B in the PG&E forecast, these renewable energy prices are used only for incremental power that is needed above PG&E's existing RPS contracts. For Alameda CCA, these prices are used as the basis for its entire RPS-eligible portfolio.

MRW additionally included a premium for the portion of Alameda CCA's RPS portfolio assumed in each scenario to be located in Alameda County. While solar energy is anticipated to provide the largest share of incremental supply located in-county, the solar resource in Alameda is not as strong as in the areas being developed to supply the contracts discussed above. As a result, the cost of solar generation in Alameda is expected to be higher than the contract prices we have assumed for non-Alameda supplies. Additionally, there are economies of scale in solar power development that mean small, local solar projects will cost more than the utility-scale projects upon which the average contract prices were derived. Based on information provided in the CPUC's current RPS calculator, which provides cost estimates for renewable energy projects located around California, large solar projects in Alameda are expected to have a 15% premium over projects in areas with the best solar resource. Generation from smaller projects (<3 MW) in Alameda are assumed to cost 55% more than the base contract price assumed in our forecast.

Given the high levels of renewable energy assumed in each of the scenarios, and the variable patterns of renewable energy production, there are likely to be periods during which the renewable energy projects with which the Alameda CCA has contracted are producing more than its customers require.[10] This excess supply must be managed by the Alameda CCA and will likely add to its overall supply costs. For the purpose of this assessment, MRW assumed that the excess renewable supply would be sold at 10% of the cost of additional renewable purchases

[10] The annual oversupply is equal to the sum of positive hourly differences between RPS generation and load.

made at other times to make up for the annual shortfall.[11] The cost of managing excess renewable energy supply could be reduced through the use of unbundled RECs. For example, in hours when the CCA is long on renewable energy, it could simply resell the energy in the spot market and keep the REC rather than selling the bundled REC at a discount in one hour when it has excess supply and purchasing a bundled REC in another hour.

Non-Renewable Energy Cost Forecast

MRW separated the costs of non-renewable energy generation into two components: power production costs and greenhouse gas costs. The forecast methodologies for these cost elements, described below, are consistent with the forecast methodologies used for these cost elements in the PG&E rate forecast.

Since natural gas generation is typically on the margin in the California wholesale power market, power production costs for market power are driven by the price for natural gas. MRW forecasted natural gas prices based on current NYMEX market futures prices for natural gas, projected long-term natural gas prices in the EIA's *2015 Annual Energy Outlook,*[12] and PG&E's tariffed natural gas transportation rates.[13] MRW used a standard methodology of multiplying the natural gas price by the expected heat rate for a gas-fired unit and adding in variable operations and maintenance costs to calculate total power production costs.

In addition to power production costs, the cost of energy generated in or delivered to California also includes the cost of greenhouse gas allowances that, per the state's cap-and-trade program, must be procured to cover the greenhouse gases emitted by the energy generation. MRW developed a forecast of the prices for these allowances based on the results of the California Air Resources Board's (ARB's) auctions for Vintage 2015 allowances,[14] increased annually in proportion to the auction floor price increases stipulated by the ARB's cap-and-trade regulation.[15] MRW estimated the emissions rate of Alameda CCA non-renewable power supply based on an estimated heat rate for market power multiplied by the emissions factor for natural gas combustion.[16]

Capacity Cost Forecast for Non-Renewable Power

[11] This is because it is likely that other potential buyers of renewable energy at times when Alameda has excess supply will also have lower need for additional renewable energy.

[12] U.S. Energy Information Administration. "2015 Annual Energy Outlook," Table 13.

[13] Pacific Gas & Electric, Burnertip Transporation Charges. Tariff G-EG, Advice Letter 3664-G, January 2016 and Tariff G-SUR, Advice Letter 3699-G, April 2016.

[14] Auction results available at http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

[15] California Code of Regulations, Title 17, Article 5, Section 95911.

[16] U.S. EIA. Electric Power Annual (EPA), February 16, 2016, Table A.3. https://www.eia.gov/electricity/annual/html/epa_a_03.html

To estimate Alameda CCA's capacity requirements, MRW developed a forecast of Alameda CCA's peak demand in each year and subtracted the net qualifying capacity credits provided by Alameda CCA's renewable power purchases. This is appropriate because the renewable energy prices used in this analysis reflect prices for contracts that supply both energy and capacity. If Alameda CCA purchases renewable energy via energy-only contracts, Alameda CCA's need for capacity will be greater than forecasted here, but these higher costs will be fully offset by the lower costs for the renewable energy.

MRW estimated current peak demand for Alameda CCA's load using the 2013-2014 monthly bills for all the current PG&E clients in Alameda county[17] and PG&E's class-average load profiles. We forecasted changes to this peak demand based on the California Energy Commission's forecast of changes to peak demand in PG&E's planning area.[18] We calculated capacity requirements as 115% of the expected peak demand in order to include sufficient capacity to fulfill resource adequacy requirements. We applied a consistent methodology to obtain the peak demand growth rates and capacity requirements for PG&E.

To estimate the cost of Alameda CCA's capacity needs, MRW priced capacity purchases at the median price of recent Resource Adequacy purchases, escalated with inflation.[19]

[17] Monthly bills corresponding to 2013 and 2014 for all the clients in Alameda county provided by PG&E.

[18] California Energy Commission. Demand Forecast. PG&E Forecast Zone Results Mid Demand Case, Sales Forecast, Central Valley Region. December 14, 2015.

[19] CPUC 2013-2014 Resource Adequacy Report Final, August 5, 2015, page 23 Table 11.

Appendix C. Forecast of PG&E's Generation Rates

MRW developed a forecast of PG&E's generation rates for comparison with the rates that Alameda CCA will need to charge to cover its costs of service. MRW developed the forecast for the years 2017-2030 using publicly available inputs, including cost and procurement data from PG&E, market price data, and data from California state regulatory agencies and the U.S. Energy Information Administration. The structure of the rate forecast model and the basic assumptions and inputs used are described below.

Generation Charges

PG&E's generation costs fall into four broad categories: (1) renewable generation costs, (2) fixed costs of non-renewable utility-owned generation, (3) fuel and purchased power costs for non-renewable generation, and (4) capacity costs. Each of these categories is evaluated separately in the rate forecast model, and underlying these forecasts is a forecast of PG&E's generation sales.

Sales Forecast

PG&E's generation cost forecast is driven in large part by the amount of generation that PG&E will need to obtain to meet customer demand. To forecast PG&E's electricity sales, MRW started with the 2016-2030 sales forecast that PG&E provided in its January 2016 Renewable Energy Procurement Plan ("RPS Plan") filing with the CPUC.[20] This forecast predicts 4% annual sales reductions through 2020 and anemic sales growth of 0.2% per year from 2020-2025, before increasing to close to 1% per year from 2025-2030.[21]

Renewable Generation

The starting point for MRW's analysis is PG&E's "RPS Plan," in which PG&E discusses its plan for meeting California's Renewable Portfolio Standard (RPS) targets and provides the annual amount and cost of renewable generation currently under contract through 2030. PG&E's RPS Plan shows that PG&E's current renewable procurement is in excess of the RPS requirement in each year through 2022. After 2022, PG&E's renewable generation from current contracts falls below the RPS requirements, but PG&E is projected to have enough banked Renewable Energy Credits (RECs) from excess renewable procurement in prior years to meet the RPS requirements until 2025.

MRW adopted PG&E's RPS Plan forecast of the amount and cost of renewable generation that is currently under contract. For the period starting in 2026 when PG&E's RPS Plan shows a need

[20] Pacific Gas & Electric. *Renewables Portfolio Standard 2015 Renewable Energy Procurement Plan (Final Version).* January 14, 2016. Appendix D.

[21] The near-term decline in sales in PG&E's forecast is likely attributable to the growth in CCA, in which a municipality procures electric power on behalf of its constituents instead of having them purchase their power from PG&E. While customers in the jurisdictions of these municipalities have the option to opt-out of CCA and to continue to procure power from PG&E, so far, most CCA-eligible customers have not elected for this option. CCA customers continue to procure electricity delivery services from PG&E; it is only generation services that they obtain through the CCA.

for incremental renewable procurement to meet RPS requirements, MRW added in the necessary renewable generation to meet current statutory requirements (i.e., 33% of procurement in 2020, increasing to 50% of procurement in 2030).[22] To project PG&E's cost of this incremental renewable generation, MRW used the same renewable prices used for Alameda CCA's renewable power cost forecast (see 0).

Fixed Cost of Non-Renewable Utility-Owned Generation

PG&E's rates include payment for the fixed costs of the PG&E-owned non-renewable generation facilities, which are primarily natural gas, nuclear, and hydroelectric power plants. Because these costs are not tied to the volume of electricity that PG&E sells, their annual escalation is not driven by the price of fuel and other variable inputs. Instead, they escalate at a rate that stems from a combination of cost increases and depreciation reductions. These escalation rates are determined in General Rate Case (GRC) proceedings, which occur roughly every three years.

As a starting point for the forecast, MRW used the adopted 2016 fixed costs for these facilities.[23] For the period between 2017 and 2019, MRW estimated escalation rates based on PG&E's proposal in its 2017 GRC application,[24] estimating in the base case that PG&E would receive 2/3 of its requested GRC increases and in an alternate scenario that PG&E would receive 50% of its requested increases in order to evaluate a window of potential GRC outcomes. For subsequent years, MRW estimated in the base case that PG&E's generation fixed costs would increase by the 6.2% annual average growth rate approved and implemented for these cost over the last ten years. In the alternate scenarios, we instead applied a 4.9% annual average growth rate, calculated as 20% discount off the base case growth rate.[25] These escalation rates are in nominal dollars (i.e., some of the escalation is accounted for by inflation).

[22] MRW additionally allowed for the purchase of additional renewable generation when renewable prices are below market prices, subject to some purchase limits, including a 50% cap on renewable generation relative to the entire generation portfolio. This leads to additional renewable purchases from 2027-2029 in the Low Renewable Price scenario. Starting in 2030, the RPS requirement is 50%, and no additional renewable purchases are allowed, per the rules of the model, in order to maintain grid reliability.

[23] Pacific Gas & Electric. Annual Electric True-Ups for 2016. Advice Letter 4696 E-A. January 4, 2016. Table 2.

[24] Pacific Gas & Electric 2017 GRC Request, A.15-09-001, Exhibit PG&E-10, Tables E-3 and E-4.

[25] Historic growth rates calculated from Pacific Gas & Electric Advice Letters 2706-E-A, AL 3773-E, 4459-E, 4647-E, and 4755-E. New power plant costs were excluded from these calculations since costs of new plants are offset, at least in part, by a reduction in fuel and purchased power costs.

Table 1: PG&E's Generation Fixed Costs, 2011-2016[26]
(Nominal $ Million)

	2011	2012	2013	2014	2015	2016
Generation Fixed Costs	1,400	1,530	1,550	1,710	1,860	1,840
Annual Cost Increase		9%	1%	10%	9%	-1%

MRW made adjustments to this GRC forecast to account for the likely retirement of the Diablo Canyon nuclear units at the end of the units' current licenses in 2024 and 2025. As of April 2015, PG&E was undecided as to whether it would pursue a license extension for the Diablo Canyon units.[27] There is ample reason for this uncertainty. For example, the CPUC has stated that PG&E will be required to present a thorough assessment of the cost-effectiveness of relicensing, including a number of studies exploring reliability, security, and safety implications;[28] PG&E will also be required to undertake a massive cooling system modification project before operating the nuclear plant past 2024 (per state regulations implementing the Federal Clean Water Act, Section 316(b));[29] an independent panel of peer reviewers to recent federal- and state-required PG&E seismic studies has unresolved concerns over these studies;[30] and the U.S. Nuclear Regulatory Commission is requiring PG&E to conduct additional earthquake hazard analysis because initial post-Fukushima studies showed a hazard level above the original design basis for the plant.[31] Given the uncertainties surrounding the continued operation of the plant, MRW assumed in the base case that the Diablo Canyon units would be shut down at the end of their current licenses.

In an alternate relicensing scenario, MRW included costs for the cooling system modification project that would be required.[32] To estimate annual ratepayer costs from this project, we conservatively used PG&E's $4,489 million cost estimate for a closed cycle cooling system,[33]

[26] 2011-2013: CPUC Decision 11-05-018, pages 2 and 15; and 2014-2016: CPUC Decision 14-08-032, Appendix C, Table 1 and Appendix D, Table 1.

[27] California Energy Commission. "2015 Integrated Energy Policy Report," February 24, 2016 ("2015 IEPR"), pages 177-178. http://www.energy.ca.gov/2015_energypolicy/

[28] 2015 IEPR, page 178.

[29] California State Water Resources Control Board. "Fact Sheet: Once-Through Cooling Policy Protects Marine Life And Insures Electric Grid Reliability," http://www.swrcb.ca.gov/publications_forms/publications/factsheets/docs/oncethroughcooling.pdf

[30] 2015 IEPR, pages 180-183.

[31] 2015 IEPR, page 184.

[32] California State Water Resources Control Board. "Fact Sheet: Once-Through Cooling Policy Protects Marine Life And Insures Electric Grid Reliability,"

[33] Subcommittee Comments on Bechtel's Assessment of Alternatives to Once-Through-Cooling for Diablo Canyon Power Plant. November 18, 2014, page 10.

depreciated over a 20-year period. MRW did not include costs for the CPUC-required cost-effectiveness study or for the investments that, based on the finding of the study, may be required to shore up the safety and reliability of the plant and its spent fuel management program because these costs are not well defined at this point.

Fuel and Purchased Power Costs for Non-Renewable Generation

Each spring, PG&E files a forecast with the CPUC of its fuel and purchased power costs for the upcoming year in its "ERRA" filing, which PG&E updates and finalizes in November. MRW relied on PG&E's November 2015 ERRA testimony,[34] adjusted to remove renewable generation costs, as the starting point for the forecast of fuel and purchased power costs for PG&E's non-renewable generation.

To escalate these costs through the forecast period, MRW forecasted changes to natural gas prices and greenhouse gas cap-and-trade program compliance costs, which are the major drivers of change to these costs. The natural gas price forecast is based on current NYMEX market futures prices for natural gas, forecasted natural gas prices in the U.S. EIA's *2015 Annual Energy Outlook*, and PG&E's tariffed natural gas transportation rates. This forecast is the same forecast used in the forecast of Alameda CCA's wholesale power costs (see 0).

Cap-and-trade program compliance costs are estimated based on (1) PG&E's forecast of carbon dioxide emissions in 2016;[35] (2) a forecast of PG&E's fossil generation supply, developed by subtracting expected renewable, hydroelectric, and nuclear generation from PG&E's projected wholesale power requirement; and (3) a forecast of greenhouse gas allowance prices. The greenhouse gas allowance price forecast is the same as used in the forecast of Alameda CCA wholesale power costs and is based on the results of the California Air Resources Board's (ARB's) most recent allowance auctions, increased annually in proportion to the auction floor price increases stipulated by the ARB's cap-and-trade regulation (see 0).

The MRW rate model calculates total fuel and purchased power costs by escalating natural gas prices based on the natural gas price forecast described above, escalating nuclear fuel prices based on the EIA forecast of fuel costs for nuclear plants, escalating water costs for hydroelectric projects and the capacity costs of power purchase contracts with inflation, and pricing market power at the same market power price used for Alameda CCA's purchases. The model then sums the cost for each of these resources and adds in projected cap-and-trade compliance costs to this total cost.

[34] PG&E Update To Prepared 2016 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation, filed with the CPUC in proceeding A.15-06-001 on Nov 5, 2015, pages 14 and 24.

[35] PG&E Update To Prepared 2016 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation, filed with the CPUC in proceeding A.15-06-001 on Nov 5, 2015, Table 11-2.

Capacity Costs

PG&E must procure capacity to meet 115% of its anticipated peak demand in order to fulfill its resource adequacy requirement. PG&E's own power plants can be used to meet this requirement, as can power plants with which PG&E has contracts.

To estimate PG&E's capacity requirements, MRW started with the Capacity Supply Plan that PG&E submitted to the California Energy Commission in 2015,[36] which forecasts PG&E's peak demand and existing capacity resources for each of the years 2013-2024. With limited exception,[37] MRW used PG&E's data where publicly available and extended the forecasts to 2030. In extending these forecasts, we used assumptions that are consistent with those used in our assessments of energy sales and costs, including load growth escalation and the projected retirement of PG&E's nuclear plant. We also added in anticipated capacity from new renewable procurement and from new energy storage and adjusted the calculation to account for the portion of Resource Adequacy credits that is allocated to non-bundled customers.

As with the Alameda CCA's capacity cost forecast, MRW priced capacity at the median price of recent Resource Adequacy capacity sales, escalated with inflation.[38]

Rate Development

Following the methodologies described above, MRW developed a forecast of PG&E's generation revenue requirement and divided these expenses by the expected PG&E sales in order to obtain a forecast of the system-average generation rate. We calculated annual escalators based on these system-average rates and applied them to the generation rates that are currently in effect for each customer class.[39]

[36] California Energy Commission, Energy Almanac, Utility Capacity Supply Plans from 2015. September 4, 2015

[37] The main exception is that we increased energy efficiency and demand response growth to comply with SB 350 requirements to double energy efficiency by 2030 and the anticipated continuation of CPUC demand response initiatives.

[38] CPUC 2013-2014 Resource Adequacy Report Final, August 5, 2015, page 23 Table 11.

[39] PG&E Advice Letter AL-4805-E, effective March 24, 2016.

Appendix D. Detailed Pro Forma and CCA Rates

Case-Legend	
Base	B
High natural gas price	G
High PCIA	P
Diablo Canyon relicensed	D
High renewable prices	R
Low PG&E portfolio costs	L
Stress Scenario	S

Scenario	Case	Rates ($/MWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	B	CCA generation	6.0	6.2	6.1	6.2	6.4	6.6	6.6	6.8	7.0	7.2	7.4	7.7	7.9	8.1
1	B	Exit fees	2.1	2.1	2.0	1.9	1.5	1.5	1.4	1.2	1.1	1.2	1.1	1.0	0.9	0.8
1	B	CCA Reserve Fund	0.9	0.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	B	PG&E generation	9.7	9.8	9.9	10.3	10.6	10.9	10.9	10.8	10.2	9.9	10.1	10.4	10.6	10.9
1	G	CCA generation	6.8	7.2	7.3	7.7	7.9	8.0	8.1	8.2	8.4	8.7	8.9	9.0	9.2	9.4
1	G	Exit fees	2.0	2.0	1.9	1.9	1.5	1.5	1.5	1.5	1.3	1.2	1.1	1.0	0.9	0.8
1	G	CCA Reserve Fund	1.0	0.6	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	G	PG&E generation	9.9	10.2	10.2	10.7	10.9	11.1	11.2	10.9	10.6	10.7	10.9	11.2	11.4	11.7
1	P	CCA generation	6.0	6.2	6.1	6.2	6.4	6.6	6.6	6.8	7.0	7.2	7.4	7.7	7.9	8.1
1	P	Exit fees	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
1	P	CCA Reserve Fund	0.9	0.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	P	PG&E generation	9.7	9.8	9.9	10.3	10.6	10.9	10.9	10.8	10.2	9.9	10.1	10.4	10.6	10.9
1	D	CCA generation	6.0	6.2	6.1	6.2	6.4	6.6	6.6	6.8	7.0	7.2	7.4	7.7	7.9	8.1
1	D	Exit fees	2.1	2.1	2.0	1.9	1.5	1.5	1.4	1.3	1.2	1.3	1.2	1.1	1.0	0.9
1	D	CCA Reserve Fund	0.9	0.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	D	PG&E generation	9.7	9.8	9.9	10.3	10.6	10.9	10.9	11.2	12.8	13.1	13.3	13.7	14.0	14.3
1	R	CCA generation	6.0	6.2	6.2	6.4	6.8	7.0	7.2	7.5	7.7	8.0	8.2	8.5	8.8	9.0
1	R	Exit fees	2.1	2.1	2.0	1.9	1.5	1.4	1.3	1.1	0.9	1.0	1.0	0.9	0.8	0.7
1	R	CCA Reserve Fund	0.9	0.5	0.3	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	R	PG&E generation	9.7	9.8	9.9	10.3	10.6	10.9	11.0	10.8	10.2	10.2	10.5	10.8	11.0	11.3
1	L	CCA generation	6.0	6.2	6.1	6.2	6.4	6.6	6.6	6.8	7.0	7.2	7.4	7.7	7.9	8.1
1	L	Exit fees	2.1	2.1	2.0	1.9	1.5	1.5	1.4	1.2	1.1	1.2	1.1	1.0	0.9	0.8
1	L	CCA Reserve Fund	0.6	0.6	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	L	PG&E generation	8.7	8.8	8.9	9.3	9.5	9.8	9.8	9.7	9.2	8.9	9.1	9.4	9.6	9.8
1	S	CCA generation	6.8	7.3	7.4	7.8	8.2	8.4	8.7	8.9	9.1	9.5	9.7	9.9	10.1	10.4

1	S	Exit fees	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
1	S	CCA Reserve Fund	0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	S	PG&E generation	9.0	9.2	9.3	9.7	9.9	10.3	10.4	10.4	10.1	10.1	10.3	10.5	10.7	10.9
2	B	CCA generation	6.5	6.6	6.4	6.5	6.7	6.8	6.8	6.9	7.1	7.3	7.5	7.7	7.9	8.1
2	B	Exit fees	2.1	2.1	2.0	1.9	1.5	1.5	1.4	1.2	1.1	1.2	1.1	1.0	0.9	0.8
2	B	CCA Reserve Fund	1.0	0.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	B	PG&E generation	9.7	9.8	9.9	10.3	10.6	10.9	10.9	10.8	10.2	9.9	10.1	10.4	10.6	10.9
2	G	CCA generation	7.1	7.4	7.3	7.6	7.8	7.9	7.9	8.1	8.3	8.6	8.8	9.0	9.2	9.4
2	G	Exit fees	2.0	2.0	1.9	1.9	1.5	1.5	1.5	1.5	1.3	1.2	1.1	1.0	0.9	0.8
2	G	CCA Reserve Fund	0.9	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	G	PG&E generation	9.9	10.2	10.2	10.7	10.9	11.1	11.2	10.9	10.6	10.7	10.9	11.2	11.4	11.7
2	P	CCA generation	6.5	6.6	6.4	6.5	6.7	6.8	6.8	6.9	7.1	7.3	7.5	7.7	7.9	8.1
2	P	Exit fees	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
2	P	CCA Reserve Fund	1.0	0.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	P	PG&E generation	9.7	9.8	9.9	10.3	10.6	10.9	10.9	10.8	10.2	9.9	10.1	10.4	10.6	10.9
2	D	CCA generation	6.5	6.6	6.4	6.5	6.7	6.8	6.8	6.9	7.1	7.3	7.5	7.7	7.9	8.1
2	D	Exit fees	2.1	2.1	2.0	1.9	1.5	1.5	1.4	1.3	1.2	1.3	1.2	1.1	1.0	0.9
2	D	CCA Reserve Fund	1.0	0.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	D	PG&E generation	9.7	9.8	9.9	10.3	10.6	10.9	10.9	11.2	12.8	13.1	13.3	13.7	14.0	14.3
2	R	CCA generation	6.5	6.7	6.6	6.8	7.2	7.4	7.6	7.8	8.0	8.2	8.4	8.6	8.8	9.0
2	R	Exit fees	2.1	2.1	2.0	1.9	1.5	1.4	1.3	1.1	0.9	1.0	1.0	0.9	0.8	0.7
2	R	CCA Reserve Fund	1.0	0.5	0.3	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	R	PG&E generation	9.7	9.8	9.9	10.3	10.6	10.9	11.0	10.8	10.2	10.2	10.5	10.8	11.0	11.3
2	L	CCA generation	6.5	6.6	6.4	6.5	6.7	6.8	6.8	6.9	7.1	7.3	7.5	7.7	7.9	8.1
2	L	Exit fees	2.1	2.1	2.0	1.9	1.5	1.5	1.4	1.2	1.1	1.2	1.1	1.0	0.9	0.8
2	L	CCA Reserve Fund	0.1	0.9	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	L	PG&E generation	8.7	8.8	8.9	9.3	9.5	9.8	9.8	9.7	9.2	8.9	9.1	9.4	9.6	9.8
2	S	CCA generation	7.1	7.4	7.5	7.9	8.3	8.5	8.8	9.0	9.2	9.5	9.7	9.9	10.1	10.4
2	S	Exit fees	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
2	S	CCA Reserve Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	S	PG&E generation	9.0	9.2	9.3	9.7	9.9	10.3	10.4	10.4	10.1	10.1	10.3	10.5	10.7	10.9
3	B	CCA generation	6.5	6.9	7.0	7.4	7.9	8.0	8.0	8.2	8.3	8.5	8.7	8.9	9.1	9.2
3	B	Exit fees	2.1	2.1	2.0	1.9	1.5	1.5	1.4	1.2	1.1	1.2	1.1	1.0	0.9	0.8
3	B	CCA Reserve Fund	1.0	0.5	0.4	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	B	PG&E generation	9.7	9.8	9.9	10.3	10.6	10.9	10.9	10.8	10.2	9.9	10.1	10.4	10.6	10.9
3	G	CCA generation	7.1	7.5	7.6	8.0	8.4	8.5	8.5	8.6	8.8	9.0	9.2	9.4	9.6	9.8
3	G	Exit fees	2.0	2.0	1.9	1.9	1.5	1.5	1.5	1.5	1.3	1.2	1.1	1.0	0.9	0.8
3	G	CCA Reserve Fund	0.9	0.7	0.4	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	G	PG&E generation	9.9	10.2	10.2	10.7	10.9	11.1	11.2	10.9	10.6	10.7	10.9	11.2	11.4	11.7
3	P	CCA generation	6.5	6.9	7.0	7.4	7.9	8.0	8.0	8.2	8.3	8.5	8.7	8.9	9.1	9.2
3	P	Exit fees	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1

3	P	CCA Reserve Fund	1.0	0.5	0.4	0.1	0.1	0.0	0.0	0.0	-0.2	-0.7	-0.3	0.0	0.0	0.0
3	P	PG&E generation	9.7	9.8	9.9	10.3	10.6	10.9	10.9	10.8	10.2	9.9	10.1	10.4	10.6	10.9
3	D	CCA generation	6.5	6.9	7.0	7.4	7.9	8.0	8.0	8.2	8.3	8.5	8.7	8.9	9.1	9.2
3	D	Exit fees	2.1	2.1	2.0	1.9	1.5	1.5	1.4	1.3	1.2	1.3	1.2	1.1	1.0	0.9
3	D	CCA Reserve Fund	1.0	0.5	0.4	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	D	PG&E generation	9.7	9.8	9.9	10.3	10.6	10.9	10.9	11.2	12.8	13.1	13.3	13.7	14.0	14.3
3	R	CCA generation	6.5	7.0	7.2	7.8	8.8	9.0	9.3	9.5	9.7	9.9	10.1	10.3	10.5	10.7
3	R	Exit fees	2.1	2.1	2.0	1.9	1.5	1.4	1.3	1.1	0.9	1.0	1.0	0.9	0.8	0.7
3	R	CCA Reserve Fund	1.0	0.6	0.4	0.1	0.1	0.0	0.1	0.0	-0.4	-0.8	-0.3	0.0	0.0	0.0
3	R	PG&E generation	9.7	9.8	9.9	10.3	10.6	10.9	11.0	10.8	10.2	10.2	10.5	10.8	11.0	11.3
3	L	CCA generation	6.5	6.9	7.0	7.4	7.9	8.0	8.0	8.2	8.3	8.5	8.7	8.9	9.1	9.2
3	L	Exit fees	2.1	2.1	2.0	1.9	1.5	1.5	1.4	1.2	1.1	1.2	1.1	1.0	0.9	0.8
3	L	CCA Reserve Fund	0.1	-0.1	0.0	0.0	1.2	0.0	0.0	0.0	-0.2	-0.7	-0.3	0.0	0.0	0.0
3	L	PG&E generation	8.7	8.8	8.9	9.3	9.5	9.8	9.8	9.7	9.2	8.9	9.1	9.4	9.6	9.8
3	S	CCA generation	7.1	7.6	7.8	8.4	9.2	9.4	9.8	10.0	10.2	10.4	10.6	10.8	11.1	11.3
3	S	Exit fees	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
3	S	CCA Reserve Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	S	PG&E generation	9.0	9.2	9.3	9.7	9.9	10.3	10.4	10.4	10.1	10.1	10.3	10.5	10.7	10.9

Appendix E. Greenhouse Gas Emissions and Costs

In Chapter 3 of the report, MRW provided an estimate of Alameda CCA's annual Greenhouse Gas (GHG) emissions and compared these with the emissions for the same load under the PG&E supply portfolio. The methodology used to calculate both figures is included in this appendix, along with an estimate of Alameda CCA's cost of emissions from purchased power ("indirect emissions").

Methodology for calculating Alameda CCA's indirect GHG emissions

GHG emissions for Alameda CCA will be indirect since the CCA does not plan to generate its own power (*i.e.,* the emissions are embedded in fossil-fuel power that the CCA purchases). These emissions are estimated based on (1) a forecast of the emissions rate for Alameda CCA's fossil generation supply and (2) a forecast of the amount of Alameda CCA's fossil generation supply, developed by subtracting expected renewable and hydroelectric generation from the projected wholesale power requirement to serve the CCA's load.[40]

MRW calculated the emissions rate for Alameda CCA's fossil generation supply by estimating the amount of natural gas that will need to be burned to generate the CCA's fossil generation and the GHG emissions rate for natural gas combustion.[41] The amount of natural gas needed was estimated based on the average heat rate for the marginal generation plants on the CAISO system. MRW used public data from CAISO's OASIS platform and Platt's Gas Daily reports to calculate this average heat rate for 2015.[42] MRW extended the forecast to 2030 using the expected changes to the average heat rate in California from the EIA's *2015 Annual Energy Outlook*.[43]

MRW estimated the total annual GHG emissions for the Alameda CCA program as a product of the total energy purchased at wholesale electric market (kWh) and the rate of GHG emissions (tonnes $CO_{2\text{-equivalent}}$/kWh).

[40] MRW assumed no GHG emissions for the renewable and hydroelectric supply.

[41] The GHG emissions rate for natural gas combustion is obtained from U.S. EIA. Electric Power Annual (EPA), February 16, 2016, Table A.3. https://www.eia.gov/electricity/annual/html/epa_a_03.html

[42] MRW calculated the average heat rate of the marginal generation plants in 2015 by dividing the monthly average wholesale electric market price, net of operations and maintenance costs and GHG emissions costs, by the monthly average natural gas price. For the electricity prices, we used the average of the 2015 hourly locational marginal price for node TH_NP15_GEN-APND; for the natural gas prices, we used the average of burnertip natural gas price for PG&E.

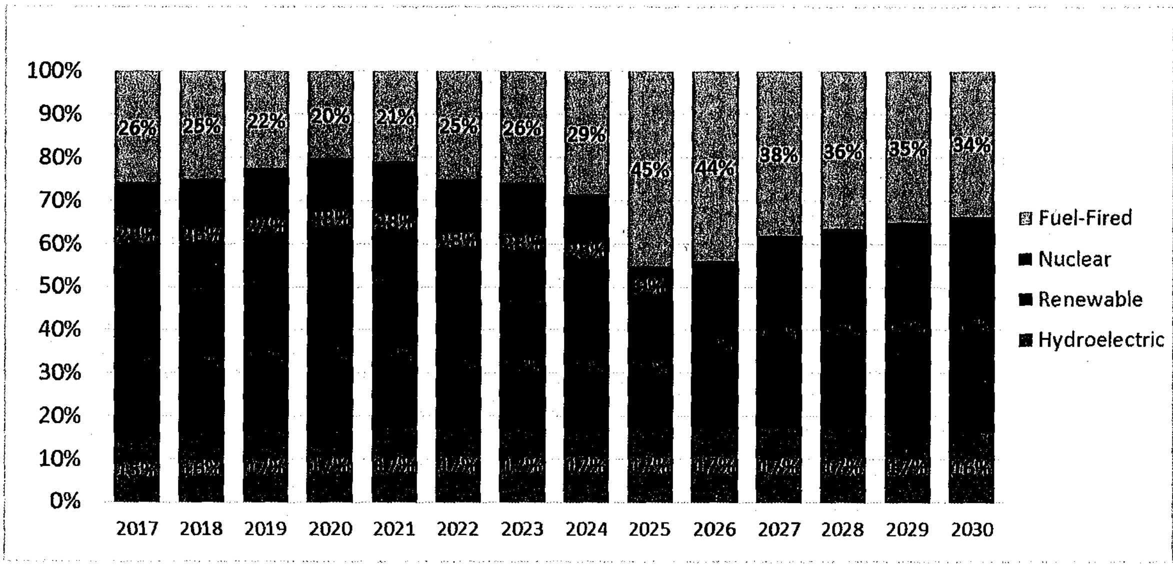
[43] U.S. Energy Information Administration. "2015 Annual Energy Outlook," Table 55.20, Western Electricity Coordinating Council. (Note that EIA does not provide a forecast of the marginal heat rate.)

Methodology for calculating GHG emissions under PG&E's supply portfolio

MRW calculated the GHG emissions for the Alameda CCA load under the PG&E supply portfolio by summing the emissions from all resources in PG&E's portfolio. MRW assumed no GHG emissions from renewable power, hydroelectric power, or nuclear generation. In order to maintain a consistent comparison, MRW used the same emissions rate to calculate the emissions from PG&E's fossil-fuel power as used for the Alameda CCA wholesale market purchases.

In order to support the analysis on Chapter 3 of the report, Figure 2 shows the PG&E portfolio. Before the closure of the Diablo Canyon, MRW estimated more than 70% of PG&E's generation portfolio based on non-fuel-fired resources. After 2025, the non-fuel-fired resources share falls to 65% according MRW estimates.

Figure 2 PG&E's generation portfolio



GHG allowance prices and GHG indirect costs

MRW developed a forecast of the prices for GHG allowances based on the results of the California Air Resources Board's (ARB's) auctions for Vintage 2015 allowances,[44] increased annually in proportion to the auction floor price increases stipulated by the ARB's cap-and-trade regulation.[45]

[44] Auction results available at http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

[45] California Code of Regulations, Title 17, Article 5, Section 95911.

Table 2 GHG Allowances price, $ per allowance

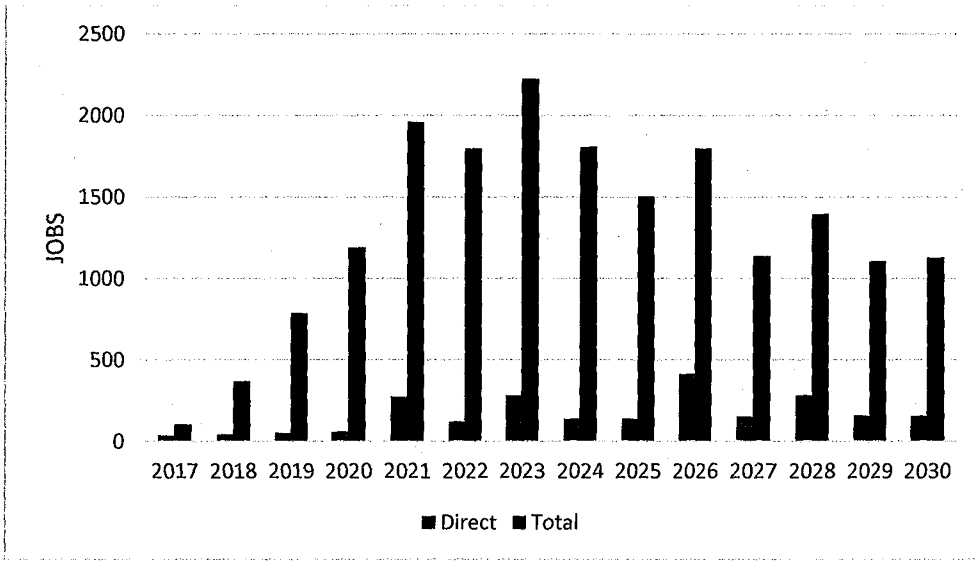
2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
14.0	15.0	16.0	17.2	18.4	19.6	21.0	22.4	24.0	25.6	27.4	29.3	31.3	33.5

MRW used these GHG allowances prices to calculate both PG&E's GHG allowances costs (direct and indirect), which are included in the PG&E rate forecast, and Alameda CCA's indirect GHG costs. The indirect GHG costs for Alameda CCA will be included in the cost of the wholesale market energy purchases. MRW estimated that these costs will be, on average, $5 per MWh delivered over the 2017-2030 period.

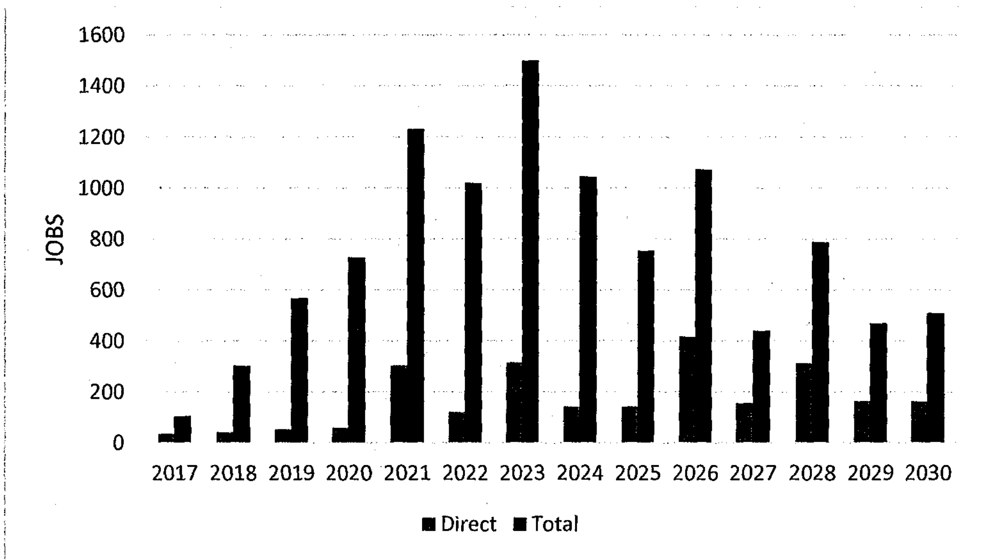
Appendix F. Macroeconomic Analysis

Additional results are provided for scenario 2 and 3 to match those presented in Chapter 5 for scenario 1. High-level results are provided for the *rest of California* region. Overview information on the REMI Policy Insight model is provided in the last section.

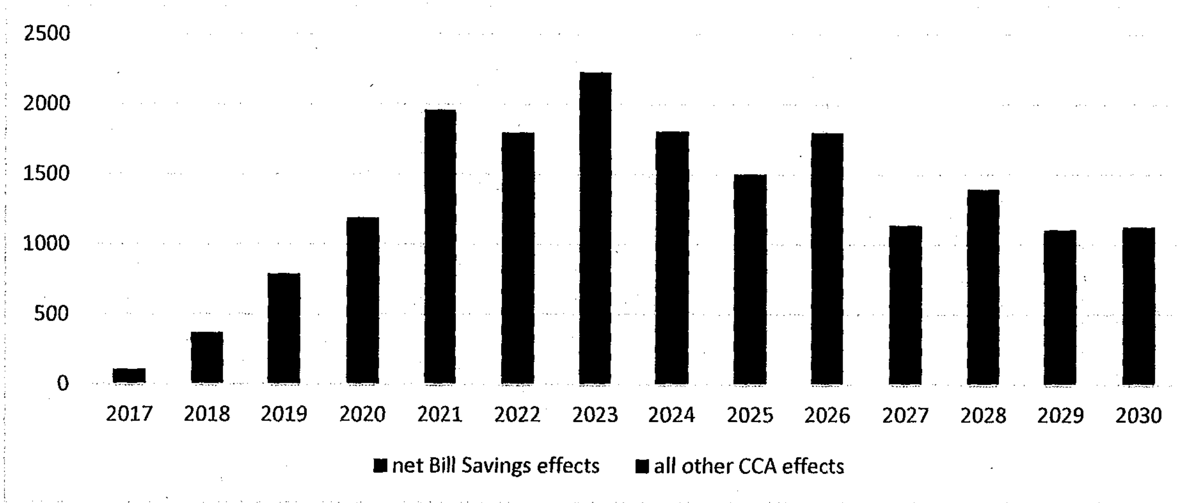
CCA Scenario 2 County Job Impacts



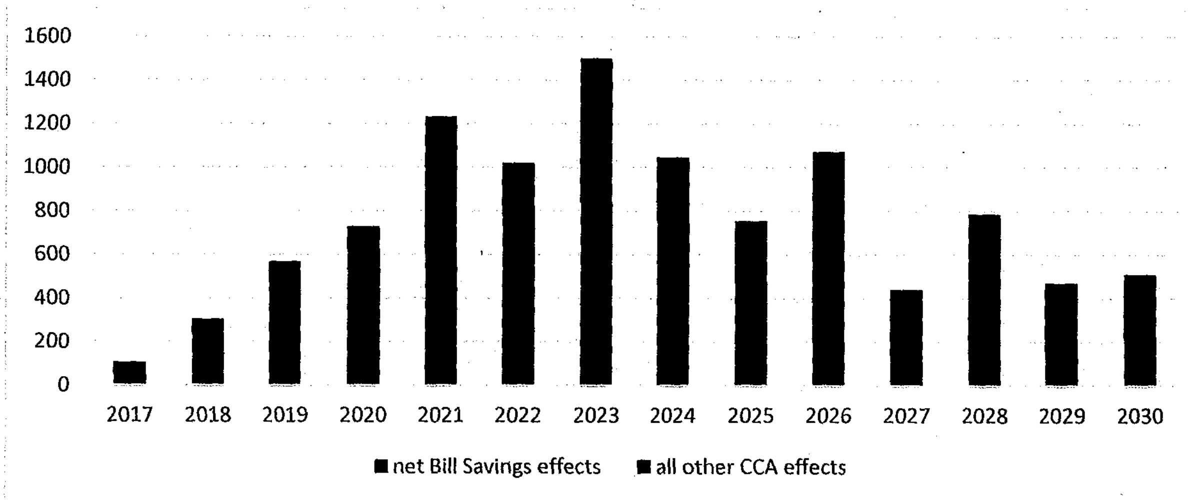
CCA Scenario 3 County Job Impacts



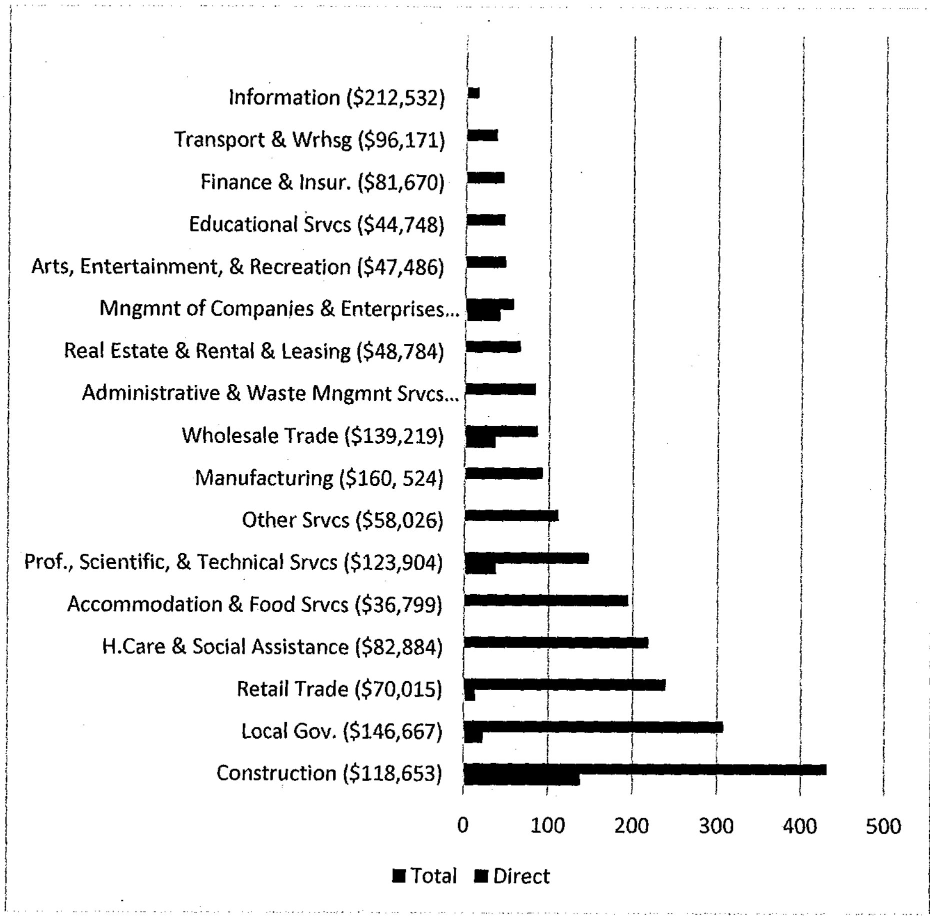
Alameda County CCA Scenario 2 Total Jobs Impacts by Source



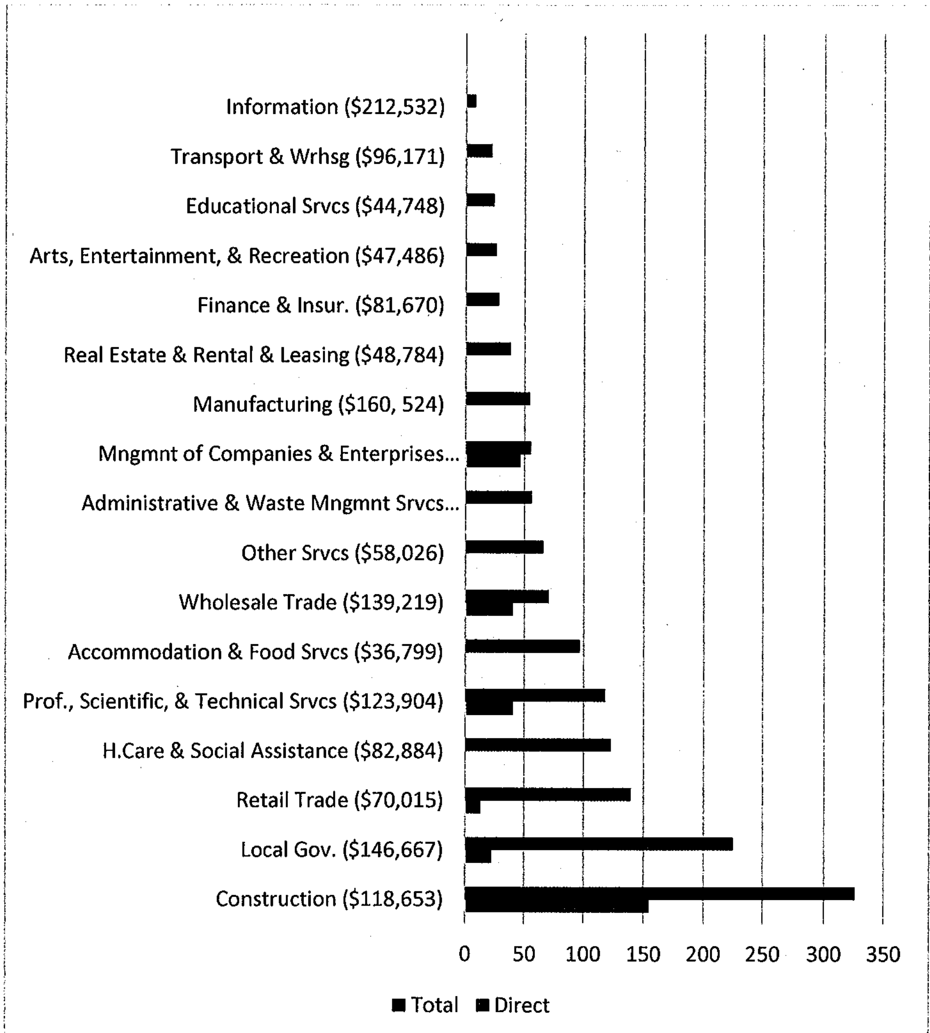
Alameda County CCA Scenario 3 Total Jobs Impacts by Source



Alameda County Jobs Changes by sector (annual earnings per worker), Scenario 2, 2023



Alameda County Jobs Changes by sector (annual earnings per worker), Scenario 3, 2023

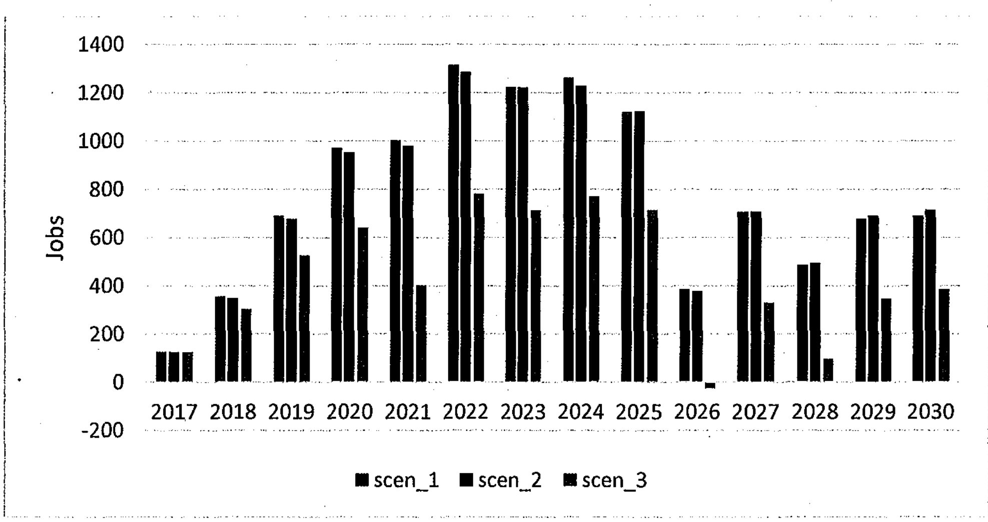


Results for rest of California Economy

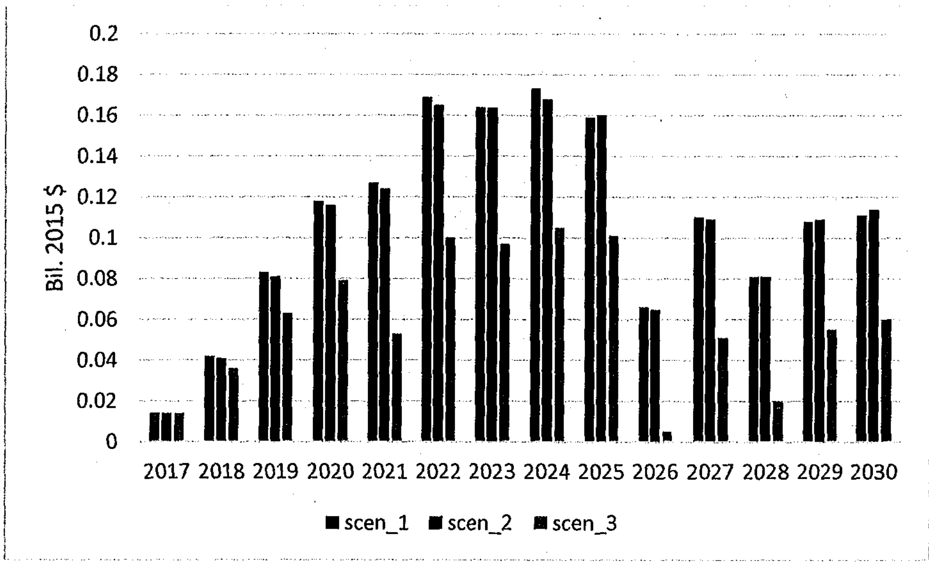
CCA Scenario	rest of CA Impacts				
	local capture on changes in RE investments & O&M (bil$) ……	*as % of roCA's Total project cost*	*as % of region's expected Economic Activity*	**Avg. Annual Direct Jobs**	**Avg. Annual *Total* Jobs**
1	-$0.155	53%	-0.0002%	-30	786
2	-$0.143	58%	-0.0002%	-24	780
3	-$0.115	40%	-0.0002%	-33	436

The local renewable investment (O&M) changes are negative as a result of expected cancellation of future PG&E renewable project and the amount of CCA funded renewable projects that would be sited in this region. The reason the *rest of California* region can create positive *total* job impacts despite small negative average annual *direct* job impacts is due economic flows between the county and this large region. In any scenario the Alameda County business segments in particular are benefitted by lower electric rates which was shown to expand their business (and jobs). When a business grows it requires more supplies and services and some of those come as *'imports from elsewhere in the state.'* Working age households that commute into Alameda County from outside also gain earned income to spend in the *rest of California* region. Since scenario 3 has the lowest rate savings it is also associated with the smallest *total* job impact in the *rest of California* region.

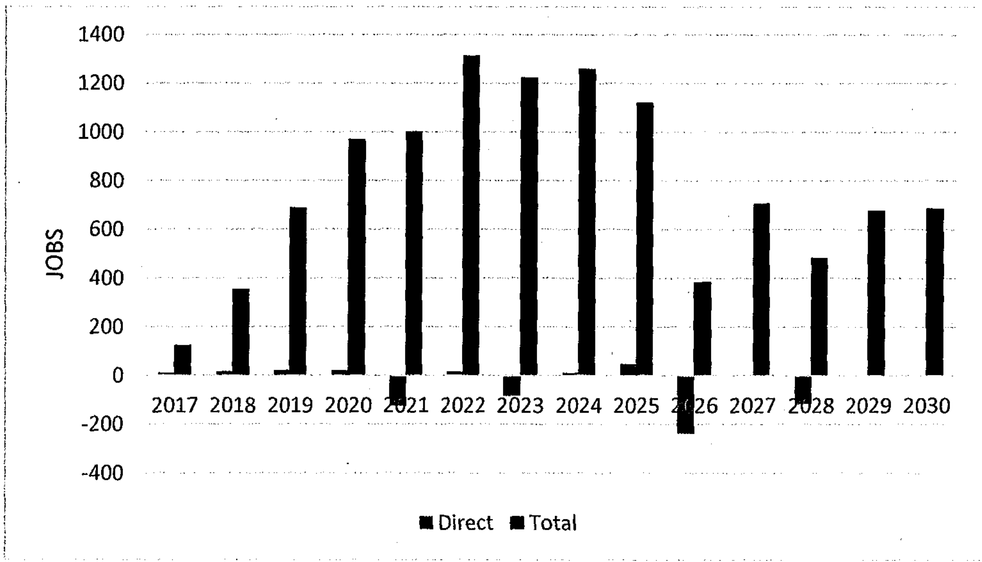
Rest of California Total Job Impacts by Scenario



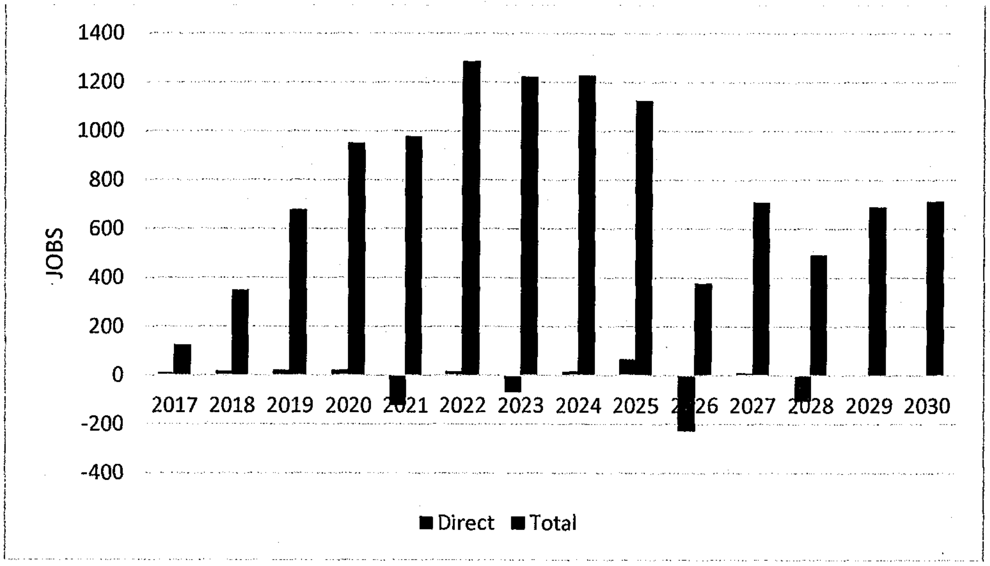
Rest of California Total GRP Impacts by Scenario



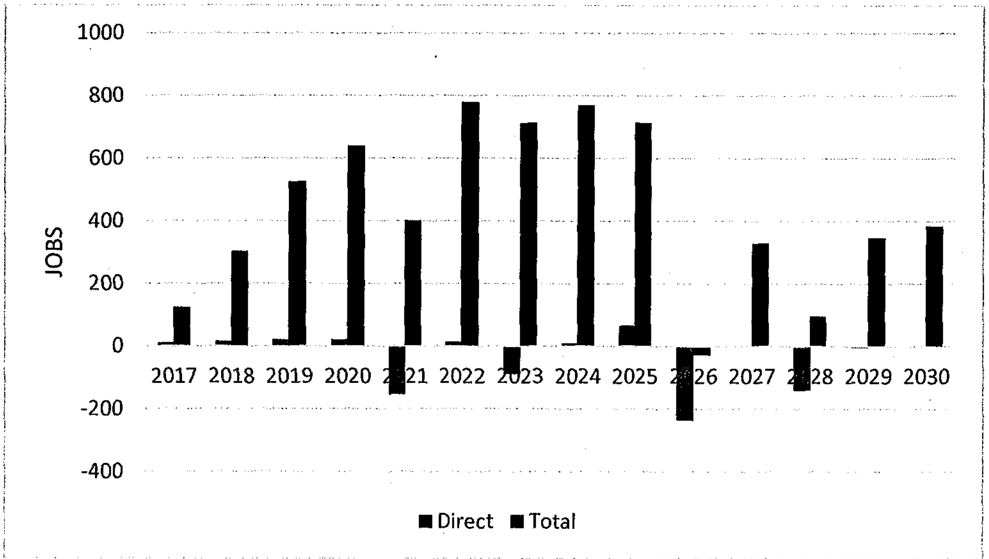
CCA Scenario 1 Rest of California Job Impacts



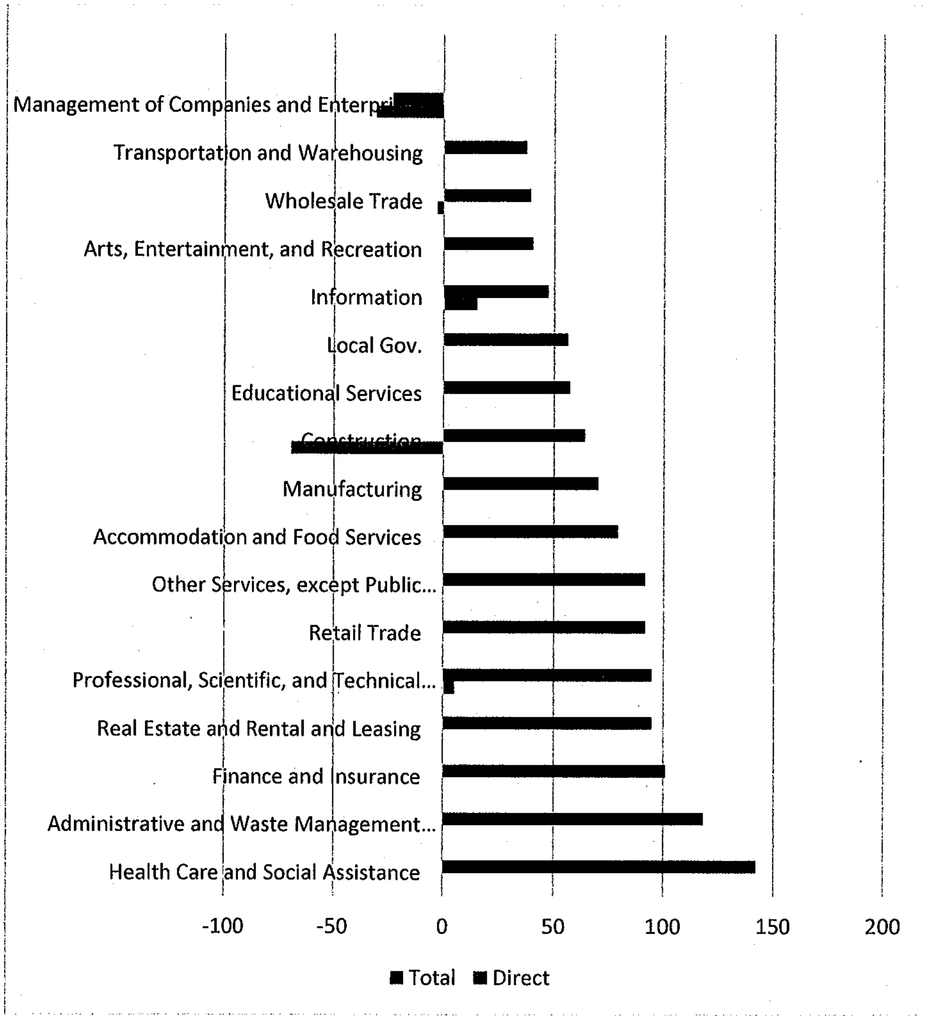
CCA Scenario 2 Rest of California Job Impacts



CCA Scenario 3 Rest of California Job Impacts



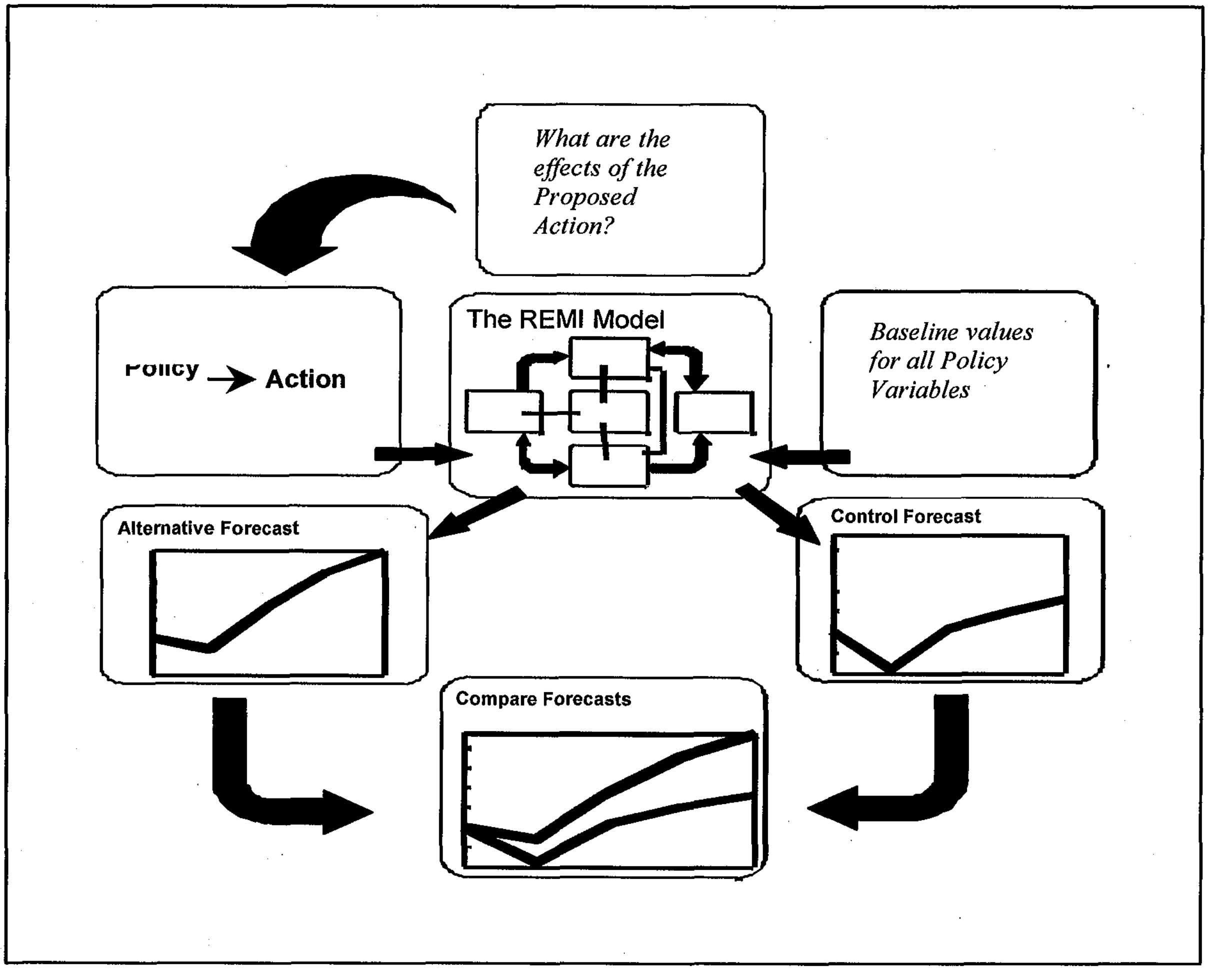
Rest of California Jobs Changes by sector, Scenario 1, 2023



About the REMI Policy Insight Model

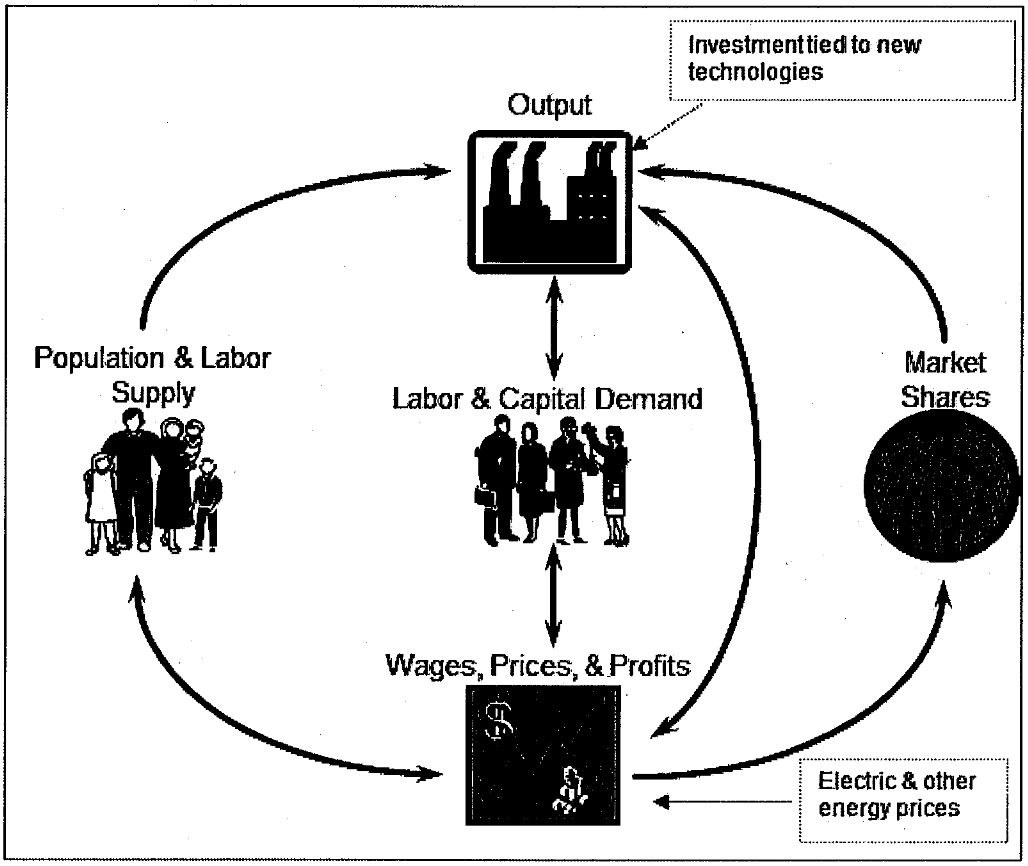
A software analysis forecasting model developed by Regional Economic Models, Inc. (REMI) of Amherst Massachusetts in the mid 1980's. It has a broad national customer base among public agencies, academic institutions, and the private-sector. It is also used in Canada (NRCan), and among other international clients. The model configuration used for this study consisted of 18 aggregate private-sector industries, plus a farm sector, a combined state/local government sector and two federal government sectors.

Economic Impacts Identified with the REMI Model



In the above figure, the central box "The REMI model" is the engine for predicting the economic and demographic dimensions of a *region-of-impact* (here Alameda County) under *no-action* (or Control forecast) and with a proposed CCA (alternative forecast). The engine is a combination structural econometric model, part input-output transactions, all with general equilibrium features – meaning *an economy can encounter a disruption (positive or negative), and over time (typically 1-3 years depending on the scale of the region and the size of the shock) re-adjust back* *to an equilibrium.* The diagram below depicts the organization of the REMI regional model in terms of the major blocks functioning in an economy and the arrows denote the feedback accounted for. Keep in mind this portrayal is at a very high-level, sparing the industry-specific details. Scenario specific changes are inserted through policy variable *levers* into the appropriate block of the model. There is another important dimension of economic response for the key region-of-impact that effectively layers on top of the below diagram – interactions with another regional economy. That additional region - *rest of California* -was explicitly modeled at the same time. The REMI model captures the flows of monetized goods and services, and commuter labor between regions when one (or both) is *shocked* by introduction of a CCA.

Core Logic of the REMI Model



Appendix G. Energy Efficiency

Contents

Energy Efficiency Research Objectives

The research undertaken by the MRW team to inform the potential for energy efficiency within the Alameda County CCA feasibility study, and associated REMI model, include the following objectives:

1. Provide a brief overview of key legislative, regulatory, and local market initiatives influencing the potential for energy efficiency.
2. Provide an assessment of the technical, economic, and market potential for energy efficiency based on tools used by the CPUC to assess potential within PG&Es service territory.
3. Provide general guidance on where CCA energy efficiency initiatives might achieve energy efficiency that are incremental to current PG&E goals.
4. Assess the current funding environment and potential costs for CCA administered energy efficiency initiatives.
5. Define the economic inputs for energy efficiency for the REMI model.

Legislative, Regulatory, and Local Market Environment for Energy Efficiency

The potential for any administrators of energy efficiency programs to deliver savings is influenced by underlying regulatory factors along with the ability of a community to deliver energy efficiency products and services. The following discussion provides a brief summary of the regulatory and service delivery environment in which energy efficiency programs administered by an Alameda County CCA would likely begin operating.

Legislative Environment

Recent legislation that is now defining the regulatory landscape under which CCA administered energy efficiency programs would operate include;

SB 350. Signed by the Governor on October 7, 2015, Senate Bill (SB) 350, the Clean Energy and Pollution Reduction Act of 2015 requires the State Energy Resources Conservation and Development Commission to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. SB 350 allows CCA energy efficiency programs to count towards statewide energy efficiency targets, and will likely have a significant impact on funding levels available for energy efficiency, and on administrative and goal setting requirements for energy efficiency program administrators, including CCA's.

AB 802. Effective September 1, 2016, the CPUC will authorize electrical and gas corporations to provide incentives, rebates, technical assistance, and support to their customers to increase the energy efficiency of existing buildings. This legislation may provide for new measure acceptance and cost effectiveness criteria that could expand opportunities for energy efficiency, including new High Opportunity Program Designs (HOPPS) currently under design.

Regulatory Environment

Rulemaking 09-11-014.[46] This ruling sought to clarify how CCAs will be able to participate in administering energy efficiency programs on behalf of the customers and/or geographic areas they serve. The ruling outlines how the commission would assess the benefits of the party's proposed program to ensure that the program meets the following objectives:

- Is consistent with current administrative rules as established pursuant to Section 381 of the public utility code.
- Advances the public interest in maximizing cost-effective electricity savings and related benefits.
- Accommodates the need for broader statewide or regional programs.

The ruling further defined the methods and guidelines for budgeting energy efficiency programs administered by a CCA, and also clarified the capacity of CCA to administer energy programs, that may also serve non-CCA customers located within the CCA's operating region.

Decision 15-10-028. As part of CPUC Decision 15-10-028 (a component of the rulemaking 13-11-005), the operation of energy efficiency programs will transition to a 'rolling portfolio' model. Historically, California has allocated ratepayer funding for energy programs through decisions made on a one, two, or three-year cycle by the California Public Utilities Commission (CPUC). This cyclical funding resulted in significant administrative burdens in the planning, assessment, and uncertainty regarding ongoing programmatic operations that potentially limited customer participation. The rolling portfolio concept, defined in the fall of 2015, initiates the conversion to a "rolling portfolio" cycle. Through this cycle, energy efficiency (EE) program administrators, including CCA's, are responsible for the creation of 5-year "business plans" in an effort to decrease administrative burden, increase transparency, and provide a more stable business platform from which to engage customers.

Local Market Environment

Alameda County has an existing and robust market of firms engaged in energy efficiency, including the capacity to provide innovative products and services to all market sectors including energy efficiency, renewable generation, energy storage, and demand response capabilities. As such, it is very likely that adequate administrative and technical support availability will be required to rapidly launch programs that would have a high likelihood of success. The following provides a brief, inexhaustive overview of this capacity.

StopWaste. StopWaste began operations in 1976 as a public agency responsible for reducing the waste stream in Alameda County. StopWatse is governed jointly by three Boards, including the Energy Council that was formed in Spring 2013 as a Joint Powers Agency to seek funding on behalf of its member agencies to develop and implement programs and policies that reduce

[46] Administrative Law Judge's Ruling Regarding Procedures For Local Government Regional Energy Network Submissions For 2013-2014 And For Community Choice Aggregators To Administer Energy Efficiency Programs

energy demand, increase energy efficiency, advance the use of clean, efficient and renewable resources, and help create climate resilient communities. StopeWaste and the Energy Council will be key stakeholders in any distributed energy resource activities associated with an Alameda County CCA.

Bay Area Regional Energy Networks (BayREN). BayREN offers 2 programs that provide benefits to Alameda County residential facilities in Alameda County, including single and multifamily dwellings. BayREN also offers commercial PACE programs in addition to a proposed innovative financing pilot program, referred to Pay-As-You-Save (PAYS). PAYS intends to retrofit 2,000 multifamily housing units in Hayward with an array of resource efficiency measures that will assist multifamily property owners monitor and reduce both water and energy use. All BayREN programs offered in Alameda County are administered by StopWaste.

PG&E. The 2015 PG&E portfolio includes 66 programs available throughout Alameda County that provide financial incentives and technical support for energy efficiency activities. These programs, listed in Appendix A, cover all market sectors and energy end uses and are representative of programs that will likely continue to operate in the coming years. PG&E spends roughly $300M to $400M annually across its service territory on programs and marketing efforts designed to promote energy efficiency.

Local Energy Efficiency and Sustainability Firms. The County has substantial local resources including public institutions and numerous public and private companies, some of which have been in continuous operation since the early 1980s.

In summary, the preceding discussion on the legislative, regulatory and market environment for energy efficiency indicates;

1. The legislative environment created by SB350, AB802, AB758, AB32 are expanding the opportunities for funding and program innovations for distributed energy resources, such as energy efficiency, along with the capacity of CCA's to implement programs.
2. Structural changes now underway through the rolling portfolio initiative (RP Decision) may reduce the overall administrative burden on program administrators and provide a more stable business platform in the form of consistent funding over longer term program cycles. Regulatory proceedings are continuing to address procedural issues that will clarify the rules of CCA program operation and budgeting issues.
3. Alameda County has significant local delivery capacity, including firms with a long history of successfully operating energy efficiency and resource management programs, including the technical and administrative capabilities needed to successfully deliver on regulatory requirements. This implies that innovative programs that incorporate emerging concepts such as High Opportunity Projects and Programs (HOPPS) or integrated demand side management (IDSM) techniques can be developed and implemented with acceptable risk.
4. Risks exists in the form duplicate efforts between established utility programs and CCA administered programs, and also the potential for customer confusion from other market entrants. In the longer term, the role of energy efficiency and related opportunities is

evolving as advances in renewable energy and storage technology change the economics associated with avoided costs, greenhouse gases priorities, and operational dynamics associated with grid management. This indicates some uncertainty in program design and delivery priorities.

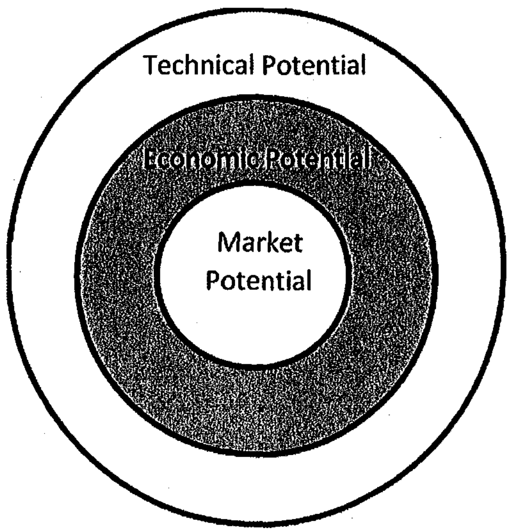
Energy Efficiency Potential

The following section provides an estimate of the overall level of energy efficiency potential in Alameda County as derived from a publically available potential model, and also provides several examples of incremental potential not represented in this model that may be developed by CCA administered programs.

Types of Energy Efficiency Forecasts and Alameda County Market Potential

Forecasts of energy efficiency potential are generally based on three levels of screening, as illustrated in **Error! Reference source not found.** and discussed below.

Figure 3. Diagram of Types of Energy Efficiency Potential



1. **Technical Potential Analysis.** Technical potential is defined as the amount of energy savings that would be possible if all technically applicable and feasible opportunities to improve energy efficiency were taken, including retrofit measures, replace-on-burnout measures, and new construction measures. Technical potential varies over time depending on market adoption and saturation of existing technologies, and the development of new technologies that are more efficient than the current market baseline. It is also a very notional metric intended to provide a benchmark that compares the current market with a hypothetical market where the most current energy efficiency technologies have been installed, and all machines and systems may be upgraded to a high level of efficiency.

2. **Economic Potential Analysis.** Using the results of the technical potential analysis, the economic potential is calculated as the total energy efficiency potential available when limited to only cost-effective measures. All components of economic potential are a subset of technical potential. Economic potential is less than technical potential because it considers the influence of financial payback on customer selection, along with regulatory requirements that exclude certain energy efficiency activates based on cost effectiveness criteria. Economic potential is also a notional metric which adjusts technical potential to account for various regulatory and market economic constraints.
3. **Market Potential Analysis.** The final output of most potential studies is a market potential analysis which is defined as the energy efficiency savings that could be expected to occur in response to specific levels of program funding and customer participation based on assumptions regarding market influences and barriers. All components of market potential are a subset of economic potential. Some studies also refer to this as the "Maximum Achievable Potential." Defining market potential requires an estimate of how much market activity occurs each year where there is an opportunity to install efficient equipment. The opportunity is often related to natural stock turnover (i.e., old equipment burns out and needs to be replaced) or the favorable economic conditions such that residents and businesses invest in energy efficiency, or the influence of codes and standards. Market potential generally does not exceed 1% of total electricity consumption in any given year, but is influenced by the level of spending and the development of new and innovative market interventions.

The assessment of energy efficiency potential in Alameda County completed for this feasibility study used outputs from the 2013[47] and 2015[48] Energy Efficiency Potential and Goals studies developed by the CPUC. These CPUC studies define the technical and economic potential for energy efficiency in PG&E's service territory, and also determine the market potential used to set energy efficiency production goals and budgets for PG&E's energy efficiency programs. Because of its size, varied economy, diverse demographics, and range of climates it is likely that both energy use characteristics and the potential for energy efficiency in Alameda County is consistent with the potential for energy efficiency in PG&E's overall service territory, with some exceptions such as a reduced presence of agricultural and oil extraction loads found elsewhere in the state. For example, a review of Alameda County electric usage data provided to the MRW team for this analysis indicates that the residential sector accounted for 29% of sales to the County by PG&E in 2013 and 2104, with non-residential sales accounting for the remaining 71%. Similarly, the CEC electric demand forecast for the overall PG&E service territory[49] indicates that the residential sector accounted for 31% of total system-wide sales for those same years, with nonresidential sales accounting for 69% of sales, consistent with the distribution of sales in Alameda County. Based on these consistencies in markets and energy usage, this analysis concludes that energy efficiency potential for electricity in PG&E's overall service

[47] 2013 California Energy Efficiency Potential and Goals Study, Final Report. Prepared for the California Public Utilities Commission by Navigant Consulting, Inc. February 14, 2014

[48] Energy Efficiency Potential and Goals Study for 2015 and Beyond, Stage 1 Final Report. Prepared for the California Public Utilities Commission by Navigant Consulting, Inc. Reference No.: 174655, September 25, 2015

[49] Form 1.1 – STATEWIDE California Energy Demand 2015 Revised - Mid Demand Case, Electricity Consumption by Sector (GWh)

territory can be allocated to Alameda County in proportion to overall electricity sales, which average approximately 7.5% of total annual PG&E electricity sales.

Figure 4 shows technical and economic electric potential as a percent of sales as presented in the 2015 CPUC potential study. Technical and economic potential start at approximately 21% and 18%, respectively in 2016 and drop to approximately 16% and 15% by 2024. Using this forecast along with PG&E electric sales data to Alameda County, **Error! Reference source not found.** provides a range of estimates of technical and economic potential during this same timeframe. This provides a notional indication of the amount of energy efficiency potential that exists in Alameda County that PG&E and any CCA administered programs would be serving.

Figure 4. Potential for Electric Savings as a Percent of Annual Sales

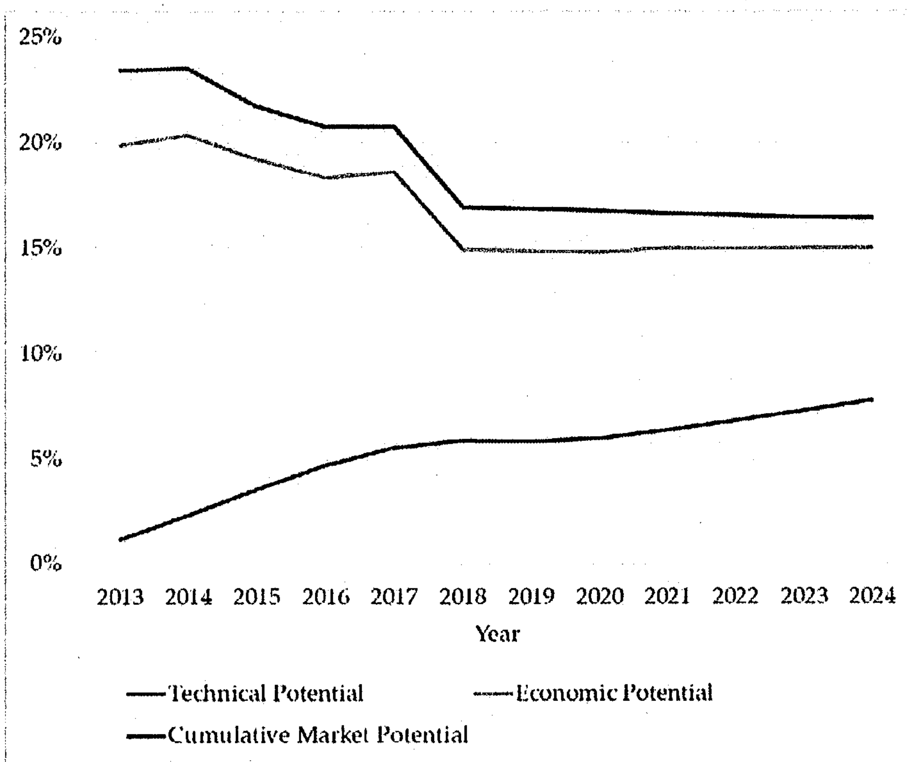


Table 3. Alameda County Average Technical and Economic Energy Efficiency Potential

Metric	Technical Potential		Economic Potential	
Range (% of sales)	21%	16%	18%	15%
Potential (GWh)	1,623	1,237	1,391	1,159

Table 3**Error! Reference source not found.** provides a summary forecast of the market potential for energy efficiency in Alameda County based on this same approach. It is important to note that the difference between technical, economic potential and market potential is that market potential represents the annual rate at which efficient equipment is installed, or the percent of the population that adopts energy efficiency practices. As such, market potential is a smaller value when compared to technical or economic potential because the natural cycle at which equipment burns out and must be replaced tends to regulate the rate at which new, high efficiency equipment can be installed, given reasonable program, market incentives, and assumptions about customer adoption rates. Market potential also recognizes that only a fraction of customers actually install high efficiency systems when it is time to replace equipment. The row labelled " PG&E Goals" represents Alameda County's share of the PG&E 2015 EE program portfolio savings target.[50] The row labelled "High Savings Scenario" represents Alameda County's share of the more aggressive energy efficiency scenarios for PG&E as defined by the 2013 CPUC potential study high savings scenario.[51] The row labelled "Incremental Potential" is the difference between PG&E's 2015 portfolio goals, and the high savings scenario and represents the total market potential that could be served by CCA administered programs.

Table 4. Alameda County Incremental Energy Efficiency Market Potential (GWh)

Year	2017	2018	2019	2020	2021	2022	2023	2024
Alameda Component of PG&E Goals	25.9	35.8	24.6	29.4	41.1	48.2	50.0	25.9
Alameda of High Savings Scenario	44.2	59.8	56.6	65.6	71.7	84.2	88.4	44.2
Incremental Potential	18.3	24.0	32.0	36.3	30.6	36.0	38.4	18.3

[50] Net GWh, as defined by the CEC Mid Additional Achievable Energy Efficiency (AAEE) forecast

[51] Referred to as the High AAEE Potential Scenario .

The forecast presented in **Error! Reference source not found.** represents an estimate of energy efficiency potential that is "net" of free-riders and represents the following types of energy efficiency measures and market sectors:

- Emerging Technologies
- E Program Measures
- Residential
- Commercial
- Industrial-Manufacturing

This forecast does not include energy efficiency potential associated with building codes, appliance standards, or estimates for the agricultural or mining market sectors.

Examples of Potential Programs and Measures

While there are countless opportunities and approaches to achieve energy efficiency, following presents several examples of technologies and programs that will yield savings above what is being targeted through the current portfolio of PG&E programs operating in Alameda County. This includes initiatives that might compliment and leverage existing technologies or programs, or highlight emerging opportunities that are in design or in early deployment.

High Efficacy LED Lighting. Commercial and residential lighting currently make up 25% of California's total statewide electricity consumption.[52] LED lighting will provide increasing opportunities for energy savings in the coming years as prices continue to fall and LED efficiency (i.e., efficacy or lumens per watt of power, lm/w[53]) improves. Figure 5 shows that between 2020 and 2030, LEDs lighting will achieve efficiencies of 200 lm/w and prices will reach parity with current CFL and incandescent prices within the next 10 years.

Table 5 shows that 200 lm/w represent a 74% reduction in current average residential lighting efficiency, and approximately a 50% reduction in average non-residential lighting efficiency. As the LED adoption rates at present are low, and because the technology and costs are both evolving rapidly and favorably, the potential exists for CCA energy efficiency programs to drive this transition by focusing on high efficacy LED applications. The potential between the current market efficacy for lighting shown in

Table 5 and a full market penetration of 200 lm/w LED lighting represents a reduction in state wide (and Alameda County) consumption of electricity of approximately 14%. While programs do exist that promote LED lighting, a program focused on the highest efficacy products, some of which currently exceed 140 lm/w[54], would provide savings that are incremental to many products

[52] California Commercial Saturation Survey. Itron Inc., August 2014 Table 5-82

[53] U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release

[54] http://www.cree.com/LED-Components-and-Modules/Products/XLamp/Discrete-Directional/XLamp-XPE-HEW

currently being installed. Capturing the highest savings possible from LED lighting and targeting 200 ln/w technologies is very important because LED lamps operate for between 20 and 30 years, and once lower efficacy lamps are installed it will be difficult to capture rapidly improving efficiencies.

Figure 5. Trends in LED Lighting Efficacy and Cost per Bulb

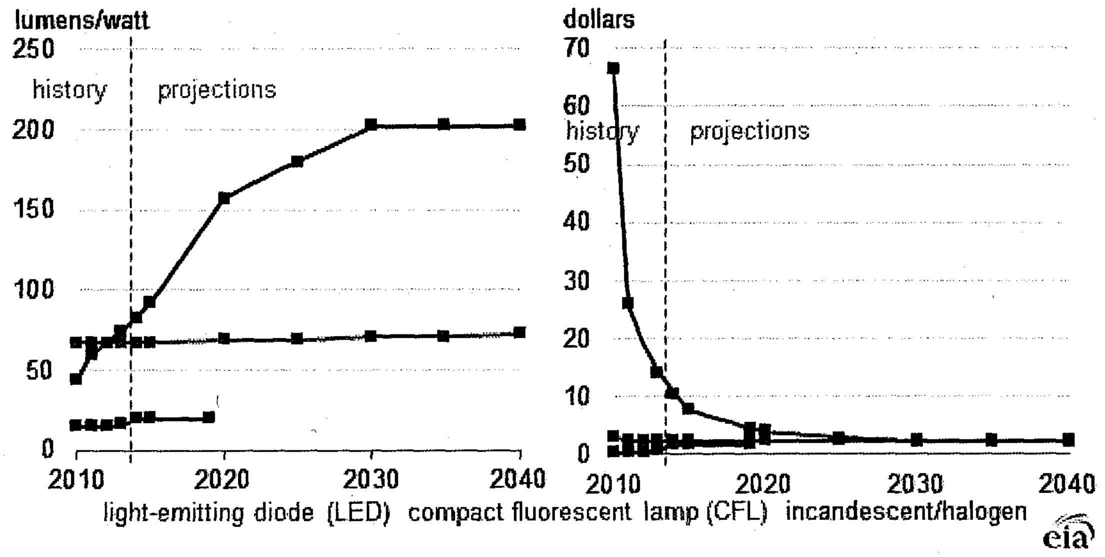


Table 5. Average Lighting Efficacy by Sector, and Potential Reductions from LED Lighting

Market Sector	Residential	Commercial	Industrial
Current est. average market lighting efficacy, lm/w	53	93	99
% reduction in energy for same light level at 200 lm/w	74%	54%	50%

Energy Controls and Information Systems. As with LED lighting, there are programs that currently deliver both energy controls and information systems, but they are not fully represented in the 2013 and 2015 potential model efforts and represent opportunities for new initiatives to contribute towards higher savings. In general, opportunities for controls and information systems is largest in the following two areas.

- **Lighting Controls.** In addition to converting to LED lighting, recent studies have shown significant potential for lighting controls. The 2015 commercial saturation study[55] included

[55] California Commercial Saturation Survey. Itron Inc., August 2014 Table 5-82

an analysis of lighting controls indicating that 67% of light commercial buildings are controlled manually while 33% are operated with various other types of lighting controls. Lighting controls in commercial buildings can save an average of 20% of lighting energy.

- **Building Information & Energy Management Systems.** Various studies indicate that the penetration of Energy Information Systems (EIS) and Energy Management Systems (EMS) are low compared to potential applications, and new ways to combine and extract value from these systems are also emerging. Additionally, the past five years has seen the growth of many new companies and applications involving energy information. Favorable trends in information systems, controls technologies, and associated costs suggest that market penetration of these technologies could be much higher. A technical analysis supporting AB802[56] forecasts the potential to leverage the combined use of these EIS and EMS technologies (referred to in that study as 'Building Information & Energy Management Systems', or BIEMS) As noted in that study, benefits at the core of the BIEMS concept include:
    - ***Energy visualization.*** Energy visualization represents the most minimalistic version of BIEMS. It uses basic utility, sub-meter, and other collected data to provide a basic visualization of energy consumption, sometimes in real time depending on data availability and frequency.
    - ***Energy analytics.*** Energy analytics go beyond energy dashboards and utilizes energy-related data to analyze building-level energy consumption characteristics. These analytics engines can perform a wide variety of functions such as uncovering opportunities to improve efficiency while supporting benchmarking efforts.
    - ***Operations and Facility Management.*** Operations and facility management services help automate and track maintenance and repair action items, including the automation of a building's maintenance schedule while reconciling operational changes in equipment/control set points. Some platforms also assist in managing capital expenditures related to equipment and asset management or helping customers evaluate any available energy supply options, including analysis of demand response opportunities.
    - ***Continuous Commissioning and Self-Healing Buildings.*** Continuous commissioning is a specialized application that several BIEMS vendors currently offer. This is closely related to operations management and typically requires the application of fault detection and diagnostics-based algorithms that track individual controls and equipment performance on an ongoing basis against ideal parameters to detect anomalies in system performance while reporting on any variance in performance.

  Building level energy savings estimates for comprehensive controls range from 10% for small building to 5% for large buildings and current saturations are estimated to be 37% across all commercial building types, indicating that significant potential exist for programs that combine both EIS and EMS systems. Programs that offer BIEMS type solutions

[56] AB802 Technical Analysis. Potential Savings Analysis. Prepared for the California Public Utilities Commission by Navigant Consulting, Inc. March 16, 2016. Reference No.: 174655.

represent potential that is underrepresented in both the current offerings of PG&E programs and underrepresented in the past CPUC potential studies.

Increased Use of Market Ready Funding and Financing Products. A CCA may be an effective platform from which to increase awareness and use of a broad array of market ready funding and financing mechanisms, some of which are designed specifically to achieve sustainability goals. Expanding the use of these mechanisms has several benefits, including an existing market capacity to lend, along with the potential for very cost effective delivery of energy efficiency without the need for rebates or other financial incentives. In general, funding and financing may be defined in two categories including 1) infrastructure and public facilities projects and 2) customer market financing. The following provides a brief description of each, and a list of over 50 currently available financing and funding tools can be found in Appendix B:

- Infrastructure and Redevelopment Public Funding and Financing. These are the mechanisms that will be selected by city planners and financiers to accomplish large redevelopment and water projects and generally include grant funding, land based financing tools such as tax increment financing, and usage fees.
- Residential and non-residential funding and financing. These are the tools that will be used to implement sustainability projects in the residential and non-residential facilities that are included within priority areas, and community wide in both existing building and new construction applications through these mechanisms. These include commercial loan products such as home equity lines and utility on bill products, targeted federal agency products such as VA or HUD loans, state agency products such as SAFEBIDCO and COIN, and tax increment financing products such as PACE financing.

More aggressive use of these market ready funding and financing programs to implement sustainability projects may offer the opportunity for a CCA program that leverages private capital in lieu of rebates to achieve various County sustainability goals.

High Opportunity Programs and Projects (HOPPs). In October 30, 2015, an amended scoping memorandum expanded the 'Rolling Portfolios' proceeding scope to include the implementation of AB 802. It established a process specifically for addressing "High Opportunity Programs or Projects" (HOPPs). HOPPs expanded to target increased energy efficiency of existing buildings, including "stranded potential" via AB 802's new approaches to valuing and measuring savings. HOPPs are intended to focus on interventions (and associated intervention strategies and savings measurement regimes that program administrators could not previously undertake). The following outlines some of the HOPPs currently being proposed or deployed as pilot programs at the time of this analysis.

- **The Residential Pay-for-Performance (P4P) HOPP (PG&E).** This pilot seeks to develop a scalable model for residential retrofits that leverages rapidly emerging market actors and products while minimizing administrative and implementation costs. The program will seek out parties referred to as "Aggregators" who will either directly or through a network of contractors perform energy efficiency interventions in customers' homes with the goal of maximizing measureable savings. Aggregators may consist of existing energy efficiency market participants, such as Property Accessed Clean Energy (PACE) loan providers, smart thermostat vendors, vertically integrated contractors, program implementers, and/or new entrants to the California market. These Aggregators will compete for funding through Power Savings Agreements (PSA).

- **The Business Equipment Early Retirement HOPP (SDG&E).** This pilot is open to all business customers in the C/I/A segments with aging HVAC equipment. Some old inefficient equipment has been kept in service past its expected useful life. Customers often choose to repair, rather than replace, their aging equipment because the current rebates offered for such measures are insufficient to defray a meaningful portion of new equipment costs. Such existing equipment may be far below current code. The untapped savings represented by replacing an old inefficient unit with a new efficient one may be considered the stranded savings potential.
- **The Tiered Incentive Custom Calculated HOPP (SDG&E).** This pilot targets mid-sized to large-sized (above 200kW) non-residential customers with retrofit opportunities for large To-Code and Above Code energy savings. Tiered Incentives will target customers who have large To-Code and Above Code projects that have previously been rejected, or those with known equipment that has not been replaced due a lack of incentives. Historically, utilities have not been able to provide incentives for projects that yield only To-Code savings which has created stranded savings in these projects.

HOPP programs offer new opportunities for CCA's to participate in existing energy efficiency programs while also allowing program administrators added flexibility in program design and savings attribution. For example, the SDG&E multifamily HOPP may offer a template for Alameda county to serve it's middle and low income customers, while the PG&E Residential Pay-for-Performance HOPP may offer opportunities for the County to share in revenue earned by aggregators of PACE program savings operating within the County, thereby providing an incentive for the County to help drive and expand these programs.

In summary, the preceding discussion on energy efficiency potential indicates that;

- A review of energy sales and market characteristics indicate that estimates of energy efficiency potential for the overall PG&E service territory can be allocated to Alameda County in proportion to the County's share of PG&E total electricity sales, which is about 7.5%.
- An analysis of the potential study developed by the CPUC to assess the market potential from energy efficiency in PG&E service territory indicates that there is the potential for energy efficiency in Alameda County beyond what is being delivered by the current suite of energy efficiency programs operating in the county.
- A review of current and emerging energy efficiency technologies and innovative new programs designs indicate that it is possible to install higher levels of energy efficiency than has historically been achieved at cost-benefit thresholds that are acceptable under current CPUC guidelines.

Current Funding Opportunities and Energy Efficiency Costs

CCA's have the opportunity use both electric and gas public purpose program funds to provide distributed energy resource programs to customers in a variety of ways. To access funds for electricity energy efficiency programs based on the most current CPUC guidance, including.[57]

Submit a plan, approved by its governing board, to the Commission for the administration of cost-effective energy efficiency and conservation programs for the aggregator's electric service customers that includes funding requirements, a program description, a cost-effectiveness analysis, and the duration of the program. To be approved, the submitted plan must satisfy the following criteria:

- Is consistent with the goals of Public Utilities Code Section 399.4.[58]
- Advances the public interest in maximizing cost-effective electricity savings and related benefits.
- Accommodates the need for broader statewide or regional programs.
- Includes audit and reporting requirements consistent with the audit and reporting requirements established by the commission pursuant to this section.
- Includes evaluation, measurement, and verification protocols established by the community choice aggregator.
- Includes performance metrics regarding the community choice aggregator's achievement of the selected objectives.

Upon submission of a successful plan, A CCA may elect to become the administrator of funds collected from the aggregator's electric service customers and collected through a nonbypassable charge authorized by the Commission may be accessed, except those funds collected for broader statewide and regional programs authorized by the commission. For CCAs electing to become

[57] As defined in Rulemaking 09-11-014

[58] Public Utilities Code Section 399.4 requires;

a. The CPUC shall continue to administer cost-effective energy efficiency programs authorized pursuant to existing statutory authority.

b. The term energy efficiency includes, but is not limited to, cost-effective activities to achieve peak load reduction that improve end-use efficiency, lower customers' bills, and reduce system needs.

c. Any rebates or incentives offered by a public utility for an energy efficiency improvement or installation of energy efficient components, equipment, or appliances in buildings shall be provided only if the recipient of the rebate or incentive certifies that the improvement or installation has complied with any applicable permitting requirements and, if a contractor performed the installation or improvement, that the contractor holds the appropriate license for the work performed.

d. The commission, in evaluating energy efficiency investments under its existing statutory authority, shall also ensure that local and regional interests, multifamily dwellings, and energy service industry capabilities are incorporated into program portfolio design and that local governments, community-based organizations, and energy efficiency service providers are encouraged to participate in program implementation where appropriate.

program administrators, the formula used to estimate the budget available for program activities is defined as;

> *CCA maximum funding = Total electricity energy efficiency nonbypassable charge collections from the CCA's customers – (total electricity energy efficiency nonbypassable charge collections from the CCA's customers * % of the applicable IOU portfolio budget that was dedicated to statewide and regional programs in the most recently authorized program cycle).*

For fiscal year 2015 the CPUC reports[59] that the total cost of customer programs for electricity indicatives in the PG&E service territory to be approximately $1.2B, as shown in Table 6, including various subprograms. Of these customer program funds, the total electricity energy efficiency nonbypassable charges referenced in Rulemaking 09-11-014 are approximately $351M (29%) are allocated for energy efficiency (EE) programs. Based on PG&E sales to Alameda County and as discussed previously, it can be assumed that approximately 7.5% of these funds, or $26.6M annually, are provided by sales of electricity to residents of Alameda County.[60]

Table 6. Allocation of Electric and Gas Utility Cost, April 2016

	Program Costs ($000)	
Customer Program	**PG&E**	**Alameda (estimated)**
Energy Efficiency	$351,311	$26,629
Demand Response	$63,978	$4,850
California Solar Initiative	$94,000	$7,125
Self-Generation Incentive Program	$29,616	$2,245
CARE Subsidy	$565,541	$42,868
CARE Administrative Expenses	$12,794	$970
Low Income Energy Efficiency	$95,089	$7,208
Total	$1,212,329	$91,895

The maximum funding equation provided in R.09-11-014 does not define the amount of the applicable IOU portfolio budget that is dedicated to statewide and regional programs, however it is estimated to be approximately 85% of available budget, based on a review of decisions addressing the approved 2015 Marin Clean Energy program portfolio. This leaves 15% of funds available for CCA administered energy efficiency programs. **Error! Reference source not**

[59] Electric and Gas Utility Cost Report. Public Utilities Code Section 913 Report to the Governor and Legislature, April 2016.

[60] Based on an analysis of PG&E electricity sales within Alameda County for 2013 and 2014 and CEC data on Alameda County and PG&E electricity usage.

found. shows that this is approximately $3.9M for programs administered by a CCA to all Alameda County residents, including PG&E customers, or $3.5M if these programs serve only CCA customers, assuming a 15% opt-out rate.

Table 7. Annual Funding Models for Non-bypassable Electric Charges

Annual Funding Models for Non-bypassable Electric Charges	Estimated Value
Program Administrator - CCA and PG&E customers	$3,941,000
Program Administrator - CCA customer only	$3,350,000

Other funds would also likely be available to help administer energy efficiency programs. An inexhaustive list of other potential funding sources are listed below. This analysis did not estimate the potential value of these funds.

- Funds from Non-bypassable Gas Charges – CPUC Decision D.14-10-046 allows CCA's to administer programs that include funds collected from natural gas customer. This analysis did not estimate the value of these funds.
- Income from CCA Operations. Income generated through CCA operations may be used to fund customer programs.
- Funding secured by StopWaste's Energy Council on behalf of any potential relationship between its member agencies and a CCA.
- Increased funding through the expansion of the CCA territory. Under current regulations it is allowed for a CCA to define its service territory more broadly than a city or county. As such, the rules that define the funding for Alameda County residents would apply to new participants in a CCA and so provide incremental program funding. For example, in 2015 Marin Clean Energy began serving customer in Contra Costa County and has increased its available program funding as a result of this enrollment.

CCA's may also choose to not administer programs. CAs' that choose to be non-administrators have the following authority as defined in R.09-11-014;

> *If a community choice aggregator is not the administrator of energy efficiency and conservation programs for which its customers are eligible, the commission shall require the administrator of cost-effective energy efficiency and conservation programs to direct a proportional share of its approved energy efficiency program activities for which the community choice aggregator's customers are eligible, to the community choice aggregator's territory without regard to customer class.*

and

The commission shall also direct the administrator to work with the community choice aggregator, to provide advance information where appropriate about the likely impacts of energy efficiency programs and to accommodate any unique community program needs by placing more, or less, emphasis on particular approved programs to the extent that these special shifts in emphasis in no way diminish the effectiveness of broader statewide or regional programs.

Assuming that a 'proportional share of its approved energy efficiency program activities for which the community choice aggregator's customers are eligible' refers to funds collected, this is estimated to average approximately $26M annually for 2013 and 2014.

Current Costs of Energy Efficiency

The savings potential for energy efficiency programs operated by an Alameda County CCA were estimated based on the amount of funding available and the unit price of energy efficiency ($/kWh). The MRW team reviewed program savings goals and program budget data for the 2015 PG&E portfolio to identify unit costs and found a broad range of costs depending on the nature of the program and whether or not the program saved only electricity, or also had natural gas savings.

Figure 6 provides a cost of supply curves which shows how much energy efficiency is available in the PG&E's 2015 portfolio, and at what price per first year gross kWh. The cost curve changes as new technologies become available, such as high efficiency LED lighting, or as new delivery models emerge, such as PACE financing. The cost curve also changes as program administrators find more efficient ways to deliver services and new methods to engage customers come to market, such as big data applications that use smart meter data to help identify customers and facilities with high opportunity for savings. Additionally, **Error! Reference s ource not found.** provides a summary of select program that are representative of the range of markets and program costs most likely to be represented in energy efficiency programs administered by an Alameda CCA.

Figure 6. Normalized First Year KWh Savings Equivalent Costs for the 2015 PG&E Portfolio

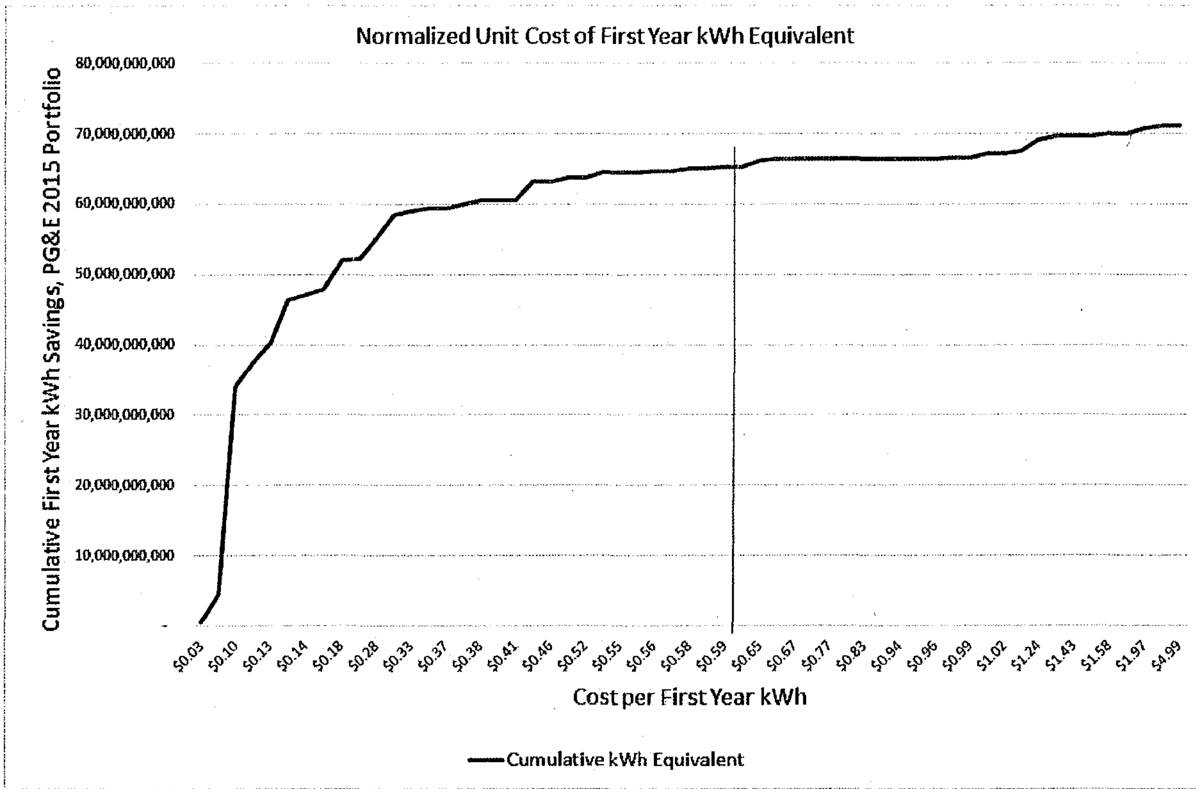


Table 8. Select Unit Costs for Energy Efficiency ($/ net kWh)

Program Admin	Sub-Program Name	Percent Program Savings that are Electric	Cost Per First Year Net kWh Equivalent
PG&E	Commercial Energy Advisor	18%	$0.18
MCE	MEA 02 - Small Commercial	79%	$0.37
PG&E	Lighting Programs Total	100%	$0.38
MCE	MEA01 2013-14 MF - Multifamily	36%	$0.59
PG&E	East Bay	93%	$0.59
Third Party	RightLights	100%	$0.75
PG&E	Energy Savers	100%	$0.81
Third Party	Energy Fitness Program	100%	$0.84

Based on this analysis, a cost of $0.61 per net first year kWh was used to represent the current unit cost of energy efficiency. As discussed in the following section, this unit cost was subsequently multiplied by the available funding to determine how much EE will be achieved in Alameda County, based on the previous assumptions that both the technical and economic market potential exists.

Remi Model Inputs

Based on the proceeding discussions regarding the availability of energy efficiency in Alameda County, and the potential for funding and associated costs, the MRW team developed the inputs for the REMI model that reflects several overarching assumptions;

- Technical, economic and market potential for energy efficiency is available in the County, including markets and technologies that are likely underrepresented in existing program offerings and offer the opportunity for new market interventions to achieve savings that are incremental to the goals currently established by the CPUC for PG&E.
- Regulators have defined the funding mechanisms for CCA's to administer energy efficiency programs, and this analysis used a conservative approach to forecast funding for energy efficiency over the MRW analysis timeframe. additional funding may be developed from multiple other source that can be used to develop additional energy savings.

Table 9 provides a summary of the factors used in the energy efficiency analysis used to develop inputs for the REMI Model, and Table 10 provides additional definitions intended to provide further transparency and clarity into the efficiency analysis.

Table 9. Factors Used in the Energy Efficiency Analysis

Analysis Factors	Value
First year available EE portfolio budget	$3,350,453
Non-Union Labor Cost	$67.26
Union Labor Cost	$79.37
Average Labor Cost	$73.32
Ratio of union hourly cot to non-union hourly costs	1.18
Incentives as % of total program costs	51.43%
% of portfolio budget where program labor is union	20.22%
Labor as a % of total measure cost	27.98%
Incentives as % of total measure cost	21.43%
Annual Energy Growth Rates (%)[61]	0.98%
PGE kW/kWh ratio	0.0158%
Average cost per EE program staff	$100,000
Labor as a percent of program spending	70.00%
Ave PG&E program cost per first year annual gross kWh	$0.42
Portfolio NTG	0.7
Average PGC $/kWh	$0.61
% of Program Budget - Incentives which are Direct Install Labor	65.65%
Incentive % total program budget - Residential	33.05%
Incentive % total program budget - Commercial	43.44%
Incentive % total program budget - Industrial	15.51%
Incentive % total program budget - Municipal	8.01%

[61] California Energy Demand 2015 Revised - Mid Demand

Table 10. Definitions Used in the Efficiency Analysis

Budget Growth Factor	Assumed change in annual budget available for Alameda CCA EE program based forecast growth in electric energy consumption from the 2015 IEPR mid-case
Baseline Budget	Assumed annual budget available for Alameda CCA EE program based on current PG&E portfolio costs and current CPUC guidelines for allocation of public goods charges available for CCA programs
Annual incremental GWh savings	Average annual potential GWh savings based on weighted average cost per GWh for relevant programs in the 2015 PG&E EE program portfolio
Annual incremental MW savings	Average annual potential MW savings based on weighted average kW/kWh ratio for relevant programs in the 2015 PG&E EE program portfolio
Non-union Labor (Man-hours)	Annual non-union labor hours to install energy efficiency projects represented in the annual incremental GWh savings estimate
Union Labor (Man-hours)	Annual union labor hours to install energy efficiency projects represented in the annual incremental GWh savings estimate
Total Labor (Man-hours)	Total union and non-union labor hours
Value of Labor ($)	Total dollar value of labor based on union and non-union rates
Value of Products Installed ($)	Total dollar value of products installed. This will be: • Incremental equipment cost for replace on burnout projects where the customer must do the project and where efficient equipment has incremental costs above code compliant equipment • Full cost for retrofit projects where customer elects to do the project and installs above code equipment
Customer Out of Pocket ($)	Total dollar value of customer out-of-pocket costs for products installed. This will be: • No out of pocket costs for direct install projects • Cost of addition funds required above any utility/CCA equipment rebate incentives
Annual Invest Needed	Budget (Admin + M&O - Incentives) + Material + Labor, or customer out of packet plus program spending
Installation Labor	Trade Labor (Union + Non Union) + Direct Installation Labor
Development Timeline	• 3 years to establish core CCA operation • 1 year for filing and development of EE programs, launch in 2021

Energy and Demand Savings Potential

The MRW teams defined the level of energy efficiency input into the REMI model would be based on incremental savings that would result from CCA administered energy efficiency programs, in excess of the levels of energy efficiency savings targeted by current PG&E initiatives. The amount of CCA program potential was calculated based on funding available and the cost of energy efficiency using the following inputs;

- Available annual budget for energy efficacy programs is based on the maximum funding equation provided in R.09-11-014, and assuming programs are administered only to CCA customers. As discussed in **Error! Reference source not found.**, this represents approximately $3.5M annually.
- The cost of energy efficiency programs most likely to be offered under and a CCA would be $0.61 per net first year kWh.
- The savings from energy efficiency during the forecast horizon would grow at a rate consistent with expected annual energy demand as defined in the 2015 CEC IEPR demand forecast.[62]
- Demand savings would be consistent with the ratio of demand to energy savings achieved by the programs most likely to be offered by a CCA as presented in **Error! Reference source not found.**.

Based on this methodology, **Error! Reference source not found.** provides a summary of REMI model energy and demand savings inputs.

Table 11. REMI Model Energy and Demand Savings Inputs

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Annual incremental energy savings (GWh)	5.7	5.8	5.9	5.9	6.0	6.0	6.1	6.1	6.2	6.3
Annual incremental demand savings (MW)	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0

Economic Activity Related to Energy Efficiency

Based on the energy efficiency analysis factors and definitions provides in Table 9 and Table 10 respectively, Table 12 provides a summary of the economic inputs from the REMI model that results from CCA administration of energy efficiency programs as defined above.

[62] Form 1.1 - PGE Planning Area California Energy Demand 2015 Revised - Mid Demand Case. Electricity Consumption by Sector (GWh)

Table 12. REMI Model Economic Inputs

Economic Activity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Annual Invest Needed	$13.3	$13.7	$14.0	$14.4	$14.8	$15.2	$15.6	$16.0	$16.4	$16.9
Installation Labor	$3.7	$3.8	$3.9	$4.0	$4.1	$4.2	$4.3	$4.5	$4.6	$4.7
Customer Out of Pocket	$9.6	$9.8	$10.1	$10.3	$10.6	$10.9	$11.2	$11.5	$11.8	$12.1
Value of Products Installed	$9.0	$9.2	$9.5	$9.7	$10.0	$10.2	$10.5	$10.8	$11.1	$11.4

Appendix 1. PG&E Programs Active in Alameda County

Table shows 2015 programs, including total PG&E service territory or statewide budgets, and capacity and energy goals, including BayREN program activities. The 'X' in the column title 'Active in Alameda County' indicates the program is either activity providing financial incentives or technical support for activities within Alameda County. With the exception of the opportunities noted earlier, these programs cover most energy efficiency measures across all market sectors, including;

- Codes & standards programs intended to enhance compliance and promote new, more aggressive codes in select jurisdictions;
- Commercial sector programs that include deemed and custom incentives as well as technical support;
- Third party programs administered by PG&E but implemented through various contractors that are target specific technology applications or specific market segments, such as refineries, health care providers, or schools;
- Residential energy efficiency programs providing rebates for the multifamily market, HVAC and whole house solution for the single family market and support for residential new construction
- Government partnership programs that include support for local governments through the East Bay Energy Watch program, as well as various institutional programs focused on universities and community colleges.
- Industrial and agricultural programs providing provide financial incentives and technical support various statewide and 3rd party, segment specific industries.
- Emerging technologies programs that support the integration of emerging technologies.

Program / Sub-Program	Active in Alameda County	Sum of Total Incentive	Sum of Total Budget	Sum of Goals therm	Sum of Goals kWh	Sum of Goals kW
Codes & Standards Programs Total		**$0**	**$16,496,433**	**1,105,275**	**282,613,013**	**44,188**
Appliance Standards Advocacy		$0	$2,396,375	0	0	0
Compliance Improvement	x	$0	$2,094,222	0	0	0
Reach Codes	x	$0	$628,267	0	0	0

2015 C&S		$0	$8,248,217	1,105,275	282,613,013	44,188
Building Codes Advocacy	x	$0	$2,396,375	0	0	0
Planning and Coordination		$0	$732,978	0	0	0
Commercial Programs Total		**$41,866,061**	**$76,775,328**	**4,817,546**	**171,723,947**	**30,271**
Savings by Design	x	$5,844,020	$11,369,534	116,869	24,426,648	6,803
Commercial Calculated Incentives	x	$9,279,579	$24,269,550	2,415,252	69,427,959	7,053
Commercial Deemed Incentives	x	$9,916,156	$17,385,210	858,364	63,124,601	11,187
Commercial Energy Advisor	x	$3,774,215	$5,475,917	1,217,783	7,960,408	3,104
Commercial HVAC	x	$13,052,092	$17,855,076	209,278	6,784,331	2,124
Commercial Continuous Energy Improvement	x	$0	$420,042	0	0	0
Third Party		**$37,126,216**	**$89,088,656**	**3,644,336**	**158,670,368**	**26,223**
Refinery Energy Efficiency Program	x	$1,350,924	$2,784,375	1,100,151	3,100,902	451
California New Homes Multifamily	x	$2,295,459	$4,218,571	120,000	1,720,000	1,316
Enhance Time Delay Relay	x	$556,009	$1,065,230	-23	918,766	1,485
Direct Install for Manufactured and Mobile Homes	x	$3,300,448	$4,541,979	-32,220	6,539,901	3,900
Monitoring-Based Persistence Commissioning	x	$609,275	$2,188,015	180,391	3,182,583	208
LodgingSavers	x	$2,125,000	$4,769,442	-13	7,189,320	1,598

School Energy Efficiency	x	$1,259,822	$3,445,459	198,645	3,345,368	325
Energy Fitness Program	x	$1,100,000	$2,706,116	-14,461	4,583,332	833
Energy Savers	x	$550,000	$1,323,747	-5,352	2,334,528	389
RightLights	x	$2,350,000	$5,075,125	-26,552	9,723,911	1,441
Furniture Store Energy Efficiency	x	$934,283	$1,544,734	-23,844	4,011,500	846
LED Accelerator	x	$1,473,572	$2,722,282	-8,085	4,664,841	954
Casino Green	x	$500,000	$1,374,085	8,055	1,762,414	347
Healthcare Energy Efficiency Program	x	$323,517	$770,461	65,152	1,323,900	189
K-12 Private Schools and Colleges Audit Retro	x	$1,256,288	$2,068,748	-23,486	2,896,447	255
Innovative Designs for Energy Efficiency Approaches (IDEEA)	x	$2,631,321	$7,924,297	185,261	5,932,977	521
Air Care Plus	x	$1,006,857	$3,471,776	371	9,024,156	902
Boiler Energy Efficiency Program	x	$641,630	$1,945,225	729,383	34,331	16
EnergySmart Grocer	x	$1,964,682	$6,637,581	15,746	17,685,129	1,847
Industrial Recommissioning Program	x	$310,000	$1,339,090	0	2,982,339	247
California Wastewater Process Optimization	x	$250,000	$953,641	0	1,774,954	204
Energy Efficiency Services for Oil Production	x	$1,980,782	$4,447,949	0	15,650,820	1,389

Heavy Industry Energy Efficiency Program	x	$4,710,923	$12,041,118	950,064	27,582,099	3,727
Industrial Compressed Air Program	x	$551,654	$1,661,321	0	5,109,111	516
Dairy Industry Resource Advantage Pgm	x	$502,246	$1,522,197	-4,826	2,261,157	484
Process Wastewater Treatment EM Pgm for Ag Food Processing	x	$364,855	$1,015,922	0	2,166,210	224
Dairy Energy Efficiency Program	x	$116,344	$427,467	-9	649,719	55
Industrial Refrigeration Performance Plus	x	$917,842	$1,562,711	0	3,850,895	347
Light Exchange Program	x	$283,295	$863,570	-25	860,177	210
Wine Industry Efficiency Solutions	x	$475,400	$1,675,216	29,992	3,362,430	554
Comprehensive Food Process Audit & Resource Efficiency Pgm	x	$433,789	$1,001,206	200,020	2,446,152	443
Residential Energy Efficiency Programs Total		**$33,850,892**	**$60,142,415**	**2,706,366**	**128,508,610**	**12,925**
Residential Energy Advisor	x	$11,026,625	$13,316,458	1,800,000	90,000,012	0
Plug Load and Appliances	x	$7,233,850	$17,791,846	223,735	32,476,767	8,129
Multifamily Energy Efficiency Rebates Program	x	$362,547	$1,685,302	90,715	981,794	94
Whole Home Upgrade Program	x	$7,537,049	$13,672,077	429,482	3,159,402	2,523
Residential New Construction	x	$2,554,476	$4,422,870	114,696	639,133	1,306
Residential HVAC	x	$5,136,345	$9,253,861	47,737	1,251,503	874

Government Partnership Programs Total		**$30,735,492**	**$70,026,290**	**1,481,091**	**107,205,951**	**12,766**
California Community Colleges	x	$1,536,198	$2,249,794	163,439	3,679,913	505
University of California/California State University	x	$6,996,526	$12,363,959	744,372	16,759,951	2,302
State of California	x	$1,777,057	$2,294,475	189,064	4,256,884	585
Department of Corrections and Rehabilitation	x	$1,597,166	$3,099,187	169,925	3,825,960	525
Local Government Energy Action Resources (LGEAR)	x	$1,926,566	$5,446,566	26,009	7,406,533	856
East Bay	x	$5,187,765	$9,685,962	56,197	21,652,559	2,487
Agricultural Programs Total		**$8,330,403**	**$17,449,635**	**1,690,030**	**70,047,080**	**20,515**
Agricultural Calculated Incentives	x	$4,231,087	$9,351,902	1,501,966	24,661,230	5,242
Agricultural Deemed Incentives	x	$1,965,211	$3,583,046	152,460	21,486,589	11,904
Agricultural Energy Advisor	x	$2,134,105	$4,049,572	35,604	23,899,261	3,369
Agricultural Continuous Energy Improvement	x	$0	$465,115	0	0	0
Lighting Programs Total		**$7,799,802**	**$12,856,179**	**-850,920**	**40,081,866**	**5,344**
Primary Lighting	x	$6,978,299	$10,710,998	-850,920	40,081,866	5,344
Lighting Innovation	x	$821,503	$1,496,016	0	0	0
Lighting Market Transformation	x	$0	$649,166	0	0	0

Industrial Programs Total		**$15,468,886**	**$24,995,292**	**8,842,652**	**33,399,496**	**4,785**
Industrial Calculated Incentives	x	$13,302,782	$20,361,087	8,591,960	27,987,597	3,515
Industrial Deemed Incentives	x	$538,604	$1,091,268	201,525	5,053,897	1,057
Industrial Energy Advisor	x	$1,627,500	$3,031,540	49,167	358,002	213
Industrial Continuous Energy Improvement	x	$0	$511,398	0	0	0
BayRen		**$6,815,663**	**$11,930,137**	**315,403**	**2,360,400**	**825**
Single Family Residential	x	$2,980,710	$4,840,886	81,794	205,724	521
Multifamily Residential	x	$3,750,000	$6,476,600	175,391	1,769,656	175
Commercial PACE	x	$84,953	$251,505	3,096	144,540	108
Pay As You Save (Green Hayward PAYS)	x	$0	$361,146	55,122	240,480	21
Emerging Technologies Programs Total		**$0**	**$5,959,297**	**0**	**0**	**0**
Technology Development Support	x	$0	$417,151	0	0	0
Technology Assessments	x	$0	$2,860,463	0	0	0
Technology Introduction Support	x	$0	$2,681,684	0	0	0
Grand Total		**$182,447,885**	**$386,918,729**	**23,959,687**	**1,000,870,238**	**158,063**

Appendix 2. Market Ready Funding and Financing Mechanisms

Market ready funding and financing mechanisms that may be used to drive energy efficiency projects in Alameda County may be defined in two categories of funding and financing mechanisms including 1) infrastructure and public facilities projects and 2) residential and non-residential market sector financing. A partial list of these mechanisms to be considered;

1. Infrastructure and Redevelopment Public Funding and Financing. These are the mechanisms that will be selected by city planners and financiers to accomplish large redevelopment and water projects and include;
   - State grant funding including
     - Greenhouse Gas Reduction Fund programs
     - Environmental Enhancement and Mitigation (EEM) Program
     - CalConserve Water Use Efficiency Revolving Fund Loan Program
   - Land-based financing tools
     - Energy Development Districts (EDD)
     - Benefit Assessment Districts
     - Enhanced Infrastructure Funding Districts (EIFD)
     - Community Facilities Districts (CFDs)
     - Tax Increment Financing,
     - California Community Capital Collaborative
   - Other Fresno propositions and usage fees
     - Proposition M Sustainable Transportation funds
2. Residential and non-residential facilities funding and financing. These are the tools that will be used to implement sustainability projects in the residential and non-residential facilities that are included within priority areas, and community wide in both existing building and new constructions through these mechanisms;
   - Non-utility private and public funding and financing
     - Small Business Investment Companies (SBIC/SBA)
     - Tax-Exempt Industrial Development Bonds
     - California Organized Investment Networks (COIN)
     - Fresno Community Development Financial Institutions (CDFI)
     - Community Investment Note
     - State Assistance Fund for Enterprise / Business and Industrial Development Corporation (SAFE-BIDCO)
     - Socially Responsible Investors (SRI)
     - Residential and Commercial PACE
     - ChargePoint® Net+ Purchase EV Charge Station Financing
     - Corporate Investment in Shared Value
     - Social Impact Bonds
     - Community Currency and Time Banks
     - Solar $mart Home Equity Line of Credit
     - Home Equity Loan
     - Home Equity Line of Credit

- SBA Loan Programs including;
    - SBA Green 504 Loans
    - 7(a) Loans
    - 504 Loans
    - Rural Business Investment Program (RBIP)
  - Housing and Urban Development (HUD) instruments including;
    - Choice Neighborhoods Planning and Implementation Grants program
    - Federal Housing Administration (FHA) 203(k) Mortgage program
    - Section 207/223(f) mortgage insurance
    - Section 202 Direct Loan Program for Housing for the Elderly or Handicapped
    - Section 3 program
  - Veteran Administration (VA) instruments including;
    - VA Home Purchase Loans
    - VA Interest Rate Reduction Refinance Loans (IRRRL)
    - Specially Adapted Housing (SAH) Grants
    - Special Housing Adaptation (SHA) Grants
    - Chapter 6 Home Loan Guaranty
- Utility and CAEATFA/CHEEF funding and financings opportunities including;
  - IOU statewide and 3rd party rebate programs
  - Low income ESA
  - On-bill financing (pilot)
  - EUC and Flex Path
  - Small Business Lease Program (pilot)

Attachment D

MRW & ASSOCIATES

MEMORANDUM

To: Alameda County Community Choice Aggregation (CCA) Steering Committee

From: Mark Fulmer

Subject: Responses to Comments on the Feasibility Study

Date: June 29, 3016

MRW & Associates (MRW) released its CCA Feasibility Study report to the Steering Committee at its June 1, 2016 meeting. A number of Steering Committee members provided written comments and questions on the report (which are attached to this memo). The following are MRW's responses to those questions and comments.

Pleasanton

1. ***Key risks:*** The ranges of risks we used we think were appropriate. In any given year, the variable might be outside the range assumed, but on average we think the range is reasonable based on historical experience. Trying to predict opt-outs as a function of rate differentials is beyond the scope of the study. That said, there have been times in the past when MCE Clean Energy had rates that were higher than PG&E but there was no discernable change in the opt-out rates.
2. ***A high local renewables case:*** A high local renewables case, which assumes that 50% of the renewables requirement of the CCA would be developed in Alameda County, is currently under development and will be included as an addendum to the report.
3. ***PCIA risk.*** MRW agrees with the recommended strategy for dealing with the PCIA (collaborating with the other CCAs) and will include it in the risk assessment section.
4. ***Forecast:*** The forecast is from the California Energy Commission and is consistent with other long-run forecasts.
5. ***Rate analysis from a customer perspective:*** The analysis compares customers' rates with the Alameda CCA versus PG&E. It is not clear what additional analyses is desired.
6. ***Renewable premiums:*** MRW endeavored to be realistic yet conservative in its renewable cost estimates and based much of its analysis on renewable energy costs on actual contract prices that have been made available in the market. Nonetheless, we understand that Steering Committee members have found these estimates to either too high or too low. By being conservative, the CCA has a higher likelihood of obtaining renewable contracts at a lower-than-anticipated pricing.
7. ***Balance sheet modeling of the sensitivity cases:*** The impacts on the balance sheet and reserves of the sensitivity cases were calculated in all of the sensitivity cases, but for the sake of length not included in the report. In no case but the "stress" were there any cash flow problems from the CCA point of view.

MRW generally concurs with the recommendations for further investigation, but note that they are beyond the scope of the feasibility study.

Hayward

Please add to Chapter 3 information about anticipated rates for large and small commercial customers. Anticipated rates for all classes are included in Appendix A.

Berkeley Climate Action Committee

1. ***Overstates costs of small solar***: MRW endeavored to be realistic yet conservative in its renewable cost estimates and based much of its analysis on renewable energy costs on actual contract prices that have been made available in the market. Nonetheless, we understand that Steering Committee members have found these estimates to either too high or too low. By being conservative, the CCA has a likelihood of obtaining renewable contracts at a lower-than-anticipated pricing.
2. ***Include a case with Community Solar:*** Modeling an explicit Community Solar program is outside the scope of the feasibility study. This of course does not mean that one is infeasible or should not be pursued; only that it was outside of the major variables needed to demonstrate the feasibility (or infeasibly) of community choice energy in Alameda County. It can be assumed, however, that any Community Solar program pricing would be similar to any other type of solar contract of similar size. It would seem, therefore, that in the study we could include a descriptive paragraph on Community Solar programs and say that the programmatic details would be developed by the CCA program after launch.
3. ***Energy efficiency estimate is too low***: The analysis was based on current funding limitations from the CPUC. Additional amounts can be achieved if the CCA chooses to using any incremental revenues for energy efficiency rather than bill savings or renewables.

Charles Rosselle

1. ***Competition among CCAs for limited carbon-free resources***. We agree that this could become an issue, and will add some discussion in the risks section.
2. ***Upward pressure on the PCIA form many CCAs:*** This issue is discussed on page 49 of the report.

The remaining points are thoughtful and should be kept in mind by the JPA and CCA planners if the EBCE moves forward.

Albany Sustainability Committee

1. ***Compare historic PG&E Rates to existing CCAs***. A comparison will be provided if historic CCA rates prove readily available.
2. ***Address potential curtailment of CCA solar PV projects by the CAISO***. The impacts of potential curtailment are acknowledged in Study. See the discussion starting at the bottom of page 15 and page 48.

3. ***Replace Diablo Canyon with energy efficiency, storage and renewables*.** First, the base case assumes that Diablo Canyon (DC) would be shut, but replaced with gas-fired resources. While PG&E recently announced it would close DC and replace it with non-fossil resources, there are no details available (including what the rate implications of that path might be). A detailed plan will be decided at the CPUC in the Long Term Procurement Plan dockets. For a press release, there is no way they can say what they'll actually do, so they might as well put the best spin on is as they can—more renewables/EE. Second. Given that DC is a 2,000 MW baseload plant, simply replacing it with just (intermittent) solar and wind and EE can't be done without a great deal of storage. The feasibility of such an approach will depend on how much storage costs come down in the next several years. Certainly as of today, having 2,000 MW of renewables combined with large amounts of storage would cause rates to increase dramatically – thus, it's reasonable to assume that a large portion of that 2,000 MW would be replaced with fossil resources.

   Qualitatively, if we replaced DC with storage, energy efficiency and renewables, the net result would be PG&E costs that are between the base PG&E cost and the Diablo Canyon Relicense cost *(really? I would think costs would be higher if you have all that storage)*, but with PG&E GHG emissions that would be significantly lower than the PG&E base case (i.e., the big jump up on PG&E GHG emissions in 2025 would not occur).

IBEW (June 18)

General problem with approach: A stochastic (probabilistic) approach preferred over the scenario (snapshot) approach taken.

A stochastic approach requires one to identify the key inputs to an analysis, assign a probabilistic distribution to each of the values, and then run numerous scenarios to get the "average" outcome as well as the distribution of outcomes. This allows one to identify not only the average expected outcome but the probability of a negative outcome (i.e., the CCA not achieving rates lower than PG&E).

While there is an appeal to this method, it requires significantly more resources that were provided for in this study. Furthermore, it requires analysts to make critical assumptions concerning the probabilistic distribution of the values. This makes the analysis significantly more opaque and difficult to verify (was the distribution function reasonable?) without necessarily adding accuracy.

The snapshot approach allows the study to select outlying values for key variables and see if they cause undue burdens on the program. This allows the JPA or other planners to take into account these variables and implement actions to contain them. Thus, overall, we think that a probabilistic approach would yield a significant increase in cost without adding any greater level of accuracy in the forecasts. It should also be noted that no other CCA technical studies have undertaken such analyses.

1. ***A&G assumptions*:** The values used from Sonoma Clean Power were consistent with other CCA feasibility studies. The fact that Sonoma has (nor has not) achieved their goals

in the relatively short time they have been in existence does not mean that they have underspent. It should also be noted that SCP has more than 100 MW of new renewable energy projects in its pipeline. It has only been operational since May of 2014.

2. ***Admin costs in workpapers***: This comment came from a draft version of the study. The actual admin costs are shown in Table 4 of the report.
3. ***Capacity Costs in workpapers:*** Both PG&E and the CCA always face the same cost for market RA and new capacity. Furthermore, the concerns expressed are for a period that is included in the generic model but not included in the results.
4. ***Opt-outs too low***: The opt out rates were highest in Marin's original communities, but in the case of Sonoma Clean Power and for new areas added to MCE, the opt-out rates have been around 10%. The opt-out rates so far for CleanPower SF are below 5%. Thus, we believe the opt-out assumptions are reasonable and in any case, a 20% opt-out rate would not make a difference in the study's conclusions.
5. ***GHG emissions rates.*** A section will be added to the Appendix explicitly laying out the greenhouse allowance pricing and how the total emissions were calculated.
6. ***Renewable Costs***: The derivation of the renewable costs is shown on pages 13-16 of the Report as well as Appendix B. There are many renewable energy contracts signed by municipal utilities and other CCAs, where the contract pricing is known. MRW endeavored to be realistic yet conservative in its renewable cost estimates. Nonetheless, we understand that Steering Committee members have found these estimates to either too high or too low.

IBEW (April 30)

General Comments

Need to see full documentation: Full documentation is provided in report, appendix and access to workpapers.

Impossible to forecast more than 5 years in advance: While it is difficult to forecast with precision the further out one is looking, the important matter here is that the PG&E and CCA forecasts rely on consistent underlying forecasts. Our analysis is internally consistent between the CCA and PG&E, and we have explored the sensitivity of the results to variations in the key parameters.

Specific Comments

"static load [forecast] for all sectors after 2019 is simply wrong" (emphasis original): The load forecast is from the California Energy Commission, and is developed by a dedicated staff there in consultation with PG&E.

"The estimate of 15% premium for Alameda County based solar projects is too small." MRW endeavored to be realistic yet conservative in its renewable cost estimates. All assumptions here documented. Nonetheless, we understand that Steering Committee members have found these estimates to either too high or too low.

The proposed power supply should have ZERO reliance on unbundled RECs. No unbundled RECS were assumed in the analysis.

GHG issues in the three scenarios: There was an error in the preliminary results slide relied upon for this comment. It has been corrected.

Greater Local build-out of renewables. As noted above, a high local renewables case will be included as an addendum to the report.

High PCIA the status quo, not a sensitivity: While the PCIA will likely exist throughout the forecast period, there is uncertainty as to what the level will be. Thus, it's reasonable to look at potentially high PCIA levels and low PCIA levels to see how they affect CCA rates. In other words, it seems appropriate to include this variable in the sensitivity analysis. The PCIA was explicitly modelled so as to be consistent with the underlying power prices and retail rate forecasts. An arbitrarily high PCIA is presented as the sensitivity case.

Economic and Jobs Analysis: The concerns raised here are addressed in the final report and appendix.

Rivera, Sandra, CDA

From:	Erik Pearson <Erik.Pearson@hayward-ca.gov>
Sent:	Tuesday, June 14, 2016 5:34 PM
To:	Rivera, Sandra, CDA
Subject:	FW: Extending the CCA Technical / Feasibility Study comment period

Hi Sandra – I'm forwarding this to you in Bruce's absence. Thanks.

Erik

From: Erik Pearson
Sent: Tuesday, June 14, 2016 5:32 PM
To: 'Jensen, Bruce, CDA'
Cc: Alex Ameri
Subject: RE: Extending the CCA Technical / Feasibility Study comment period

Hi Bruce,

Thank you for extending the comment period for the Technical Study to June 15. We would like to see the Technical Study revised to include anticipated rates for commercial customers. Chapter 3 provides potential bill savings for residential savings, but as we market EBCE to the community, we will need to have information about rates for all customers. Please add to Chapter 3 information about anticipated rates for large and small commercial customers. Thank you.

Erik Pearson, AICP
Environmental Services Manager
CITY OF HAYWARD
Utilities & Environmental Services Department
510-583-4770
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From: Jensen, Bruce, CDA [mailto:bruce.jensen@acgov.org]
Sent: Thursday, June 09, 2016 11:00 AM
To: Jensen, Bruce, CDA
Subject: Extending the CCA Technical / Feasibility Study comment period

Hello, all – we have determined that we can provide a minor extension of the review / comment period on the Tech / Feas Study from June 10, tomorrow, to end of business on June 15 next week.

I will be away from the office that day and for some time, so I will provide contact and submittal information for this and other CCA issues either tomorrow or early next week.

Thanks, and as usual, if you have any questions, let me know.

Bruce Jensen
Alameda County Planning Department
224 West Winton Avenue, Room 111
Hayward, CA 94544
(510) 670-5400

THE CITY OF

PLEASANTON.

June 15, 2016

Bruce Jensen
Alameda County Planning Department
224 West Minton Avenue, Room 111
Hayward, CA 94544

Re: Draft Technical Study for Community Choice Aggregation Program in Alameda County

Dear Mr. Jensen,

On behalf of the City of Pleasanton, I would like to acknowledge the effort that you and the Community Development Agency staff have put toward the Community Choice Aggregation Project and the East Bay Community Energy Steering Committee. The City of Pleasanton reviewed the aforementioned Technical Study and would like the following items to be considered prior to the County Board of Supervisors consideration of the Study.

1. The Study accurately highlights the key risks facing the County CCA as a financially viable organization; low power prices offered by PG&E, future high renewable prices and costs and Power Charge Indifference Assessment (PCIA). These risks are what other CCA organizations have faced as well. However, we believe the study lacked sufficient sensitivity analysis and could have provided a more robust assessment of these key risks, and how they impact customer retention and the financial viability of the CCA.

2. The Study's scenarios focus on two local renewable resources – wind and solar – as supplies for the CCA. Costs for these two sources have declined dramatically over the last decade, and in addition Alameda County does not have the potential for repowering its portion of the Altamont Pass wind project. We believe the Study could have developed a more robust analysis of the risks and impacts of high renewable prices and costs.

3. The Power Charge Indifference Assessment (PCIA) is assessed by PG&E on an annual basis on all customers who do not opt out of the CCA program. The PCIA charges by PG&E represent a significant cost to CCA customers. Some CCAs are working together in an attempt to manage upcoming risks associated with future PCIA charges. The future Alameda CCA should collaborate with the other CCAs in the Bay Area in ensuring that PCIA charges do not damage the competitive position of the new organization.

4. The loads and forecasts assumed in the report are quite lower at 0.3% compared to other municipal utilities that often use a 2% growth rate in electrical load in their long-range supply planning. This was also noted in the comments submitted by IBEW.

OPERATIONS SERVICES DEPARTMENT **P.O. Box 520, Pleasanton, CA 94566-0802**

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5. Although the scope of work (SOW) did include an analysis of rates from a scenario analysis and the Study did include such an analysis. The Study SOW did not request analysis of rates and billing issues from a customer perspective. We believe that additional consideration of the impact of rates on customers is crucial in understanding the risks to the CCA of customers either opting to remain with PG&E or returning to PG&E due to dissatisfaction with the prices offered by the Alameda CCA.

6. Local renewable energy development can provide an important long-term source of renewable electricity for the Alameda CCA. The Study's Cost and Benefit Analysis illustrates the importance of renewable costs and demonstrates how high renewable costs can all but eliminate any price advantage of the CCA over PG&E. As such, these costs represent a significant risk for the Alameda CCA.
    - Purchasing renewable power resources from within the State, but outside of Alameda County, can be carried out at a relatively low cost.
    - Building local solar and wind generation in the Bay Area is considerably more expensive.

   We are concerned that this premium underestimates the costs of renewable power development.

7. The sensitivity analysis presented in the Study highlights the key risks faced by the Alameda CCA. These risks are: low power prices offered by PG&E, future high renewable prices and costs, and PCIA charges. We recommend that additional modeling work be carried out on these three key risks and their impacts on Alameda CCA's balance sheet and reserve requirements.

Recommendations for further Study:

1. Over the past 6 years many communities have developed and implemented CCAs. As such, their experiences, strategies, and approaches to providing their customers with a cost competitive and cleaner energy alternative can be instructive. Although a comparison of CCAs was not included in the Technical Study RFP and therefore was out of scope for the Study, we believe that such a comparison could be beneficial for the CCA advisory steering committee as well as the individual municipal participants.

2. One of the key risks of a new CCA is the initial development of its rates. The RFP and the Study do not reference any specific goals or strategies around rate design. The approach to rate design should be included as it drives much of the operational and procurement decisions of the CCA.

3. Further assessment of the value and risk of hydropower is recommended based on the information provided in Scenarios 2 and 3, with each relying on a significant portion of the Alameda CCA supply portfolio being comprised on hydro generation. The consideration of purchasing hydro has financial, economic, regulatory and political risks and ramifications, which need to be further explored.

4. The Study does not assess in detail issues around customer opt-in retention. Rather the Study assumes that 15% of all customers, across all classes, would opt to remain with PG&E. Under Scenario 1 of the Study, the overall 15% opt out of customers is questionable given the negative GHG impacts of this Scenario. Because of this high opt-out rate, the viability of the CCA could be significantly at risk. Further study of Scenarios 1-3 should be conducted to further explore the opt-in retention and the viability

In summary, we find shortcomings in the Study's rate forecasting and its assessment of hydropower risks (availability and cost) and the risk of high-cost renewables creating a competitive and rate disadvantage for the CCA. Further, we suspect that some of the load forecasting and GHG savings estimates may be overly optimistic. We recommend further study of rate design, utility exit fees (Power Charge Indifference Assessment, or PCIA), and the cost premium for local (in County) renewable energy projects and the ability of the CCA to finance those projects. We further recommend benchmarking the Alameda CCA against existing Bay Area CCAs to evaluate the strategies and approaches used to provide their customers with a cost competitive and cleaner energy alternative to PG&E power.

Sincerely,

Kathleen Yurchak
Director of Operations and Water Utilities

Cc: Mayor Jerry Thorne
Vice Mayor Kathy Narum
Councilmember Karla Brown
Councilmember Jerry Pentin
Councilmember Arne Olson
Nelson Fialho, City Manager

Berkeley Climate Action Coalition

June 14, 2016

Bruce Jensen
Alameda County Planning Department
224 West Winton Avenue, Room 111
Hayward, CA 94544

Dear Mr. Jensen,

The Berkeley Climate Action Coalition, whose membership includes over 650 East Bay residents, community organizations, and educational and religious institutions working to help the City of Berkeley reach its Climate Action goals and promote greenhouse gas reductions throughout the Bay Area, writes to submit comments regarding the June 2016 technical study conducted by MRW concerning the formation of East Bay Community Energy. We are very excited about the prospect of having a community choice program in Alameda as we believe it will significantly advance our climate action and sustainable economic development goals.

We would like the final draft of the technical study to include an expanded analysis of community solar and demand reduction as follows:

1. Community solar

The MRW study estimates that the development of small-scale local solar (<3MW) will cost 55% more than projects in "areas with the best solar resource" (which we understand to mean utility-scale solar projects located in the central valley and desert of southern California). A recent report by the highly respected Rocky Mountain Institute (RMI) states that "community-scale solar" (.5-5MW) can be cost-competitive with utility-scale solar. RMI identifies measures that can be taken to reduce costs of community solar by up to 40%.

Furthermore, RMI notes that community solar is inclusive of renters and low-income households (equity goals to which that EBCE subscribes) and has siting and transmission advantages over remote utility-scale solar projects. RMI concludes that community solar is the "sweet spot" between behind-the-meter and utility-scale solar.

MRW should model buildout scenarios that substitute various quantities of community-scale for utility-scale solar development. We'd like to see how the inclusion of community solar would impact economic development and rates.

Berkeley Climate Action Coalition

2. Demand side management

MRW models 6 Gwh of annual incremental energy efficiency savings. This represents only 0.075% of load. (We are a bit confused by figures in Appendix G suggesting a much higher potential for energy efficiency and would like clarification as to what percentage of load reduction has actually been analyzed.)

SB350 calls for energy efficiency standards that are projected to reduce energy demand by 30% by 2030. Much of this demand reduction will be achieved in the electricity sector.

MRW should incorporate scenarios in which EBCE achieves demand reduction of 5% (matching Marin Clean Energy's demand reduction goal) and 18% by 2025, a national goal prescribed by RMI. Such reductions can be achieved using demand side management methods in addition to making energy efficiency improvements in buildings. Also, we propose that EBCE explore the possibility of a performance-based compensation arrangement in which the demand reduction contractor is compensated on the basis of "negawatt-hours" of energy savings.

It's important to understand now how big a role demand reduction will play in EBCE as this will affect the content of the RFP and, ultimately, the choice of program service provider(s).

Thank you for your consideration.

On behalf of the Berkeley Climate Action Coalition,

Rebecca Milliken
Climate Action Coordinator, Ecology Center
2530 San Pablo Ave, Berkeley, CA 94702
Email: rebecca@ecologycenter.org, Tel: 510-548-2220, x 240

Response to the MRW "Technical Study for Community Choice Aggregation Program in Alameda County"

Presented By: Chuck Rosselle

E-mail: crosselle@yahoo.com

Telephone: 510-206-4412

The Technical Study takes a conservative approach to the implementation of a CCA program for Alameda County by extrapolating current guidelines and practices well into the future. This approach ignores the fact that the power supply environment in both California and the nation is highly dynamic. Nevertheless, the Study provides a service in that it describes the requirements of the implementing legislation, benefits and risks inherent in the near term energy supply environment and a reasonable range of near term operational scenarios that responsible authorities can consider in establishing such a program.

The Study concludes there is a high probability that Alameda County can successfully implement a Community Energy program meeting statutory requirements which initially provides at least a minimal benefit to the ratepayers of Alameda County. This should not be surprising; Marin Clean Energy is currently providing a similar program delivering exactly this result. The Technical Study does provide assurance for decision makers that there are no current conditions in Alameda County that would preclude the implementation of an Alameda County CCA similar in function to Marin Clean Energy.

In my opinion, the Technical Study does not address biggest risk inherent in the successful operation of the CCA as an on-going business entity. In addition, it would also seem to underestimate the scope of effort required to successfully deliver value to its constituent customers. The purpose of this response is to identify the risk and describe actions necessary to mitigate the risk and successfully deliver the necessary scope of services necessary provide value. These actions are presented for consideration by those responsible for implementation of the Alameda CCA.

The single biggest risk for the Alameda County CCA program is that the overall trend towards County CCA's may be too successful. MWR has indicated that nearly all coastal counties in California (including most of the high population counties) have active plans to establish a CCA. As the number of CCA's grows, they will increasingly compete with the each other for the same sources of generation, some of which (in particular the most attractive low GHG sources) are currently controlled by the IOU's. This will likely place upward cost pressure upon these sources of power and potentially cause shortages, particularly in key power supply categories.

Additional CCA's will also put upward pressure upon the size of the PCIA. Not only will the IOU's fixed costs be spread across a smaller user base, but also the risk of stranded cost increases. This risk will continue until the CPUC and the IOU's permanently resolve any ongoing stranded asset and cost issues arising from the changing role of the IOU. High cost along with uncertainty threatens to impact the ability of the CCA's to succeed in the marketplace. If the Alameda County CCA cannot differentiate itself by offering better service or attractive pricing (hopefully both), ratepayers could fail to see the benefit of being served by the CCA as opposed to the incumbent utility, e.g. PG&E.

For the first sixty years of its existence, stable technology and fuel costs allowed the utility industry to cost effectively electrify nation utilizing the regulated monopoly model. In the 1970's the model created an overhang of stranded asses and failed projects as fuel cost volatility, turbine technological advances and regulatory compliance issues (particularly in the nuclear industry) caused utilities to make bad business decisions leading to failed capital projects. Ratepayers typically paid for these decisions as guaranteed cost recovery permitted the utilities to pass the costs of their decisions through to their customer base. Over the last twenty years the industry and its regulators have struggled to evolve a new model that rectifies the perverse incentives of the cost recovery model for an industry undergoing rapid technological change. There is no final consensus as the effort is on-going. Appendix A "The Evolution of the Power Grid" provides additional detail for anyone interested in the history of this era.

Technological advances in renewable generation, energy storage and network technology are now creating conditions which could easily lead to a new round of stranded asset risk not only for the natural gas generation infrastructure but also for the "peaking" plants being replaced by cheaper storage and the related transmission infrastructure which may become obsolete. Further complicating matters from a CCA perspective is the fact that the IOU's have traditionally favored support for their transmission infrastructure (which is subject to cost recovery) over support for an increasingly fragile distribution infrastructure, which is a cost of maintenance. Many specifics of these issues, as they relate to the Bay Area are documented by Bill Powers in "Bay Area Smart Energy 2020".

Assuming current plans come to fruition, within the next few years CCA's could easily become the majority electric power vendors for residential and commercial consumers in California. The joint CCA IOU energy supply model has the potential to succeed as the true successor to the traditional regulated monopoly model. The Alameda County CCA representing one of the largest and most diverse counties in the state, contains an enviable cross section of some of California's leading EV, battery, and solar energy technology expertise. It has the opportunity to be a leader in this transition to locally supplied power. If the CCA's do not aggressively assume this role, they risk being embroiled in the spillover from the cost pressures associated with a potentially expanding stranded asset regime along with the operational issues associated with the existing distribution network.

For many years, the utility industry presented an aspirational model of American life. Reddy Kilowatt represented the convenience and labor saving potential of wonderful devices and appliances that improved the quality of our existence. This was a direct link to Samuel Insull, the pioneering founder of Commonwealth Edison in Chicago; an early champion of the development of electric appliances as a way to increase the utilization of his turbine generators that were idle during the day when the lights were off. The entire electric appliance industry was an entrepreneurial response to this rather simple decision.

The industry's more recent struggles to restructure itself have had an unfortunate by-product of commoditizing electric power and often making its increased cost seem more like rent seeking then an opportunity for creativity. Nevertheless, some of the most innovative re-structuring is occurring at the municipal utility level; the cities of Boulder, CO and Austin, TX come to mind. The CCA initiative could achieve a similar outcome.

For a number of years, both the environmental and entrepreneurial community have recognized the potential of enhanced electrification. Not only is there great flexibility regarding how it is generated (including many which are environmentally benign), but also the economic potential is enormous. The electric power industry is the largest in the world. The biggest hurdles to enhanced electrification have been the lack of low cost, easily accessible sources of generation and the inability to store electric power in a low cost, high density, easily transportable fashion that competes with refined hydrocarbon fuels. As personally accessible electric power generation evolves and storage becomes readily accessible, the barriers to access are being lowered. Creative electrification has become an aspirational vocation for many individual entrepreneurs. What has been missing is a proper delivery mechanism.

The key is to delivery is a roadmap for the future, the framework to allow it to happen and the flexibility to respond to unexpected outcomes. The result can be a future electric power environment which is closer to the user, encouraging to innovation, and supporting the tenets of the "sharing economy":

- Enhancing experience and lifestyle
- Supporting mixed use of assets
- Supporting small scale entrepreneurialism
- Eliminating commoditization
- Taking maximum advantage of the local environment

What would such a roadmap and framework look like?

A. It would emphasize local generation.

- Local distributed generation resources reduce dependence upon competitively sourced external generation and enhance the ability to provide greater benefits to the user base and local entrepreneurs.
- Alameda County has considerable resources potentially supportive of local distributed generation (about 300,000 rooftops - many west facing, a significant commercial community, wind resources, synthetic gas generation potential, etc.). The Alameda CCA should conduct a realistic review and establish its ability to achieve eventual local energy independence, either in its entirety or for significant portions of the county. This Alameda CCA should also establish aggressive local development targets to be achieved through a combination of residential, commercial and utility grade renewables coupled with local CHP. These should be expected to be at least in the range of 50%.
- While historically uncompetitive, the cost of home PV generation is rapidly approaching competitive rates. See Appendix B for a recent LCOE discussion. The Alameda CCA should support and accelerate the adoption of this evolving capability.

- Similarly, distributed energy storage costs are rapidly approaching commercial viability. The maturation of this technology is being driven by the evolution of the EV. The Alameda CCA should support and accelerate the adoption of this technology as well.
- Net Metering has a limited lifetime. In the near future, a more realistic tariff structure will evolve in California. The Alameda CCA will be able to procure locally developed power at a competitive marginal price.

B. It would create a "one stop shop" for the local implementation of desirable generation and supporting technologies. This would include:

- A catalog of local community scale solar locations (open space, covered parking, commercial rooftops, etc.) and program to solicit local development by offering financing and permitting assistance
- A catalog of other attractive local sources of generation (wind, CHP, etc.) and a program to solicit development by offering assistance as described above
- Pre-established financing options for locally qualified suppliers. The Alameda CCA should make attractive financing for qualified suppliers a condition of any banking relationship and/or establish bond financing for local development once permitted by the maturity of the program.
- A streamlined process that supports fast-tracked permitting for projects that conform to pre-established standards (see below).

C. It would establish standards for the technologies necessary to develop the resources required to develop local energy generation and storage

- Germany has installation costs for local solar PV that are roughly half of US costs. "Soft costs" are the primary driver of this cost differential and complex permitting structures are the biggest driver of these soft cost differentials. The Alameda CCA should develop standardized configurations that support fast track permitting in order to reduce costs. Similar standards should be developed for the full spectrum of desirable generation and storage projects.
- Standardization should also include instrumentation that supports interoperability with distributed power control systems and supports demand response management.
- By providing a market and standardizing the configuration of local distributed generation technologies, the county could create configurations that enhance project asset values. This should overall enhance lender acceptance and could permit FNMA and FMCC to reduce their opposition to PACE programs, enhancing the viability of this financing option.

D. It should establish standards for a next generation Distribution Network

- The distribution network is the least robust component of the generation, transmission and distribution hierarchy. It is difficult to cost justify distribution improvements in a power generation hierarchy which classifies remote generation and transmission as high value revenue producing assets and distribution assets as a maintenance expense. In a distributed energy environment, where a greater proportion of the generating assets exist at the periphery, a robust distribution network assumes a greater level of importance.

- Further, the preponderance of events which cause unreliability in the electric supply network occur within the distribution network. Hurricane Katrina was an extreme example of this phenomenon. Several Northeastern and Mid-Atlantic States noted that micro-grids performed extremely well in comparison to the legacy network. They are aggressively pursuing the broader development of micro-grids to enhance distribution network performance. They are finding that not only do micro-grids improve customer satisfaction (due both to enhanced reliability and undergrounding), but they also improve overall network reliability and demand management capability.
- The Alameda CCA should develop a program to enhance the existing distribution network by deploying micro-grid technology.

E. It should expand the scope of the IT Services needed for success

- In addition to the basic business services described in the MRW Technical Study, the Alameda CCA should also develop the basic system support structure necessary to provide distributed generation monitoring and management. The CCA should also provide Demand Monitoring and Management capability. These services should be built to interoperate with customer devices such as PC's, smart phone and tablets.
- The services provided by these systems are critical for customer support and will provide the CCA with a valuable ability to demonstrate its value to the customer base.

F. It should aggressively promote its programs and services to the local community and take a leadership position in coordinating and lobbying for common actions within and among its peers

- Some of the initiatives and programs defined in this document may not be part of the scope of effort being currently considered by the CCA or may even be within the scope of responsibility of the IOU (PG&E).
- Nevertheless, if the CCA is to provide a successful, value added service to the citizens of the county (its customer base, I would strongly encourage that the CCA either on its own initiative or in conjunction with its peers negotiate to provide a complete set of services of the type defined herein.

Appendix A

The Evolution of the Power Grid

The Development of the Modern Power Industry

Thomas Edison opened the first commercial power plant in the United States on Pearl Street in Manhattan in September of 1882. The Pearl Street plant used a coal fired boiler to drive a reciprocating steam engine that in turn provided direct current (DC) power to one square mile of Lower Manhattan. The DC power generated by Edison could only be distributed up to a mile from the generation site. The Pearl Street plant was the first to standardize power generation for multiple users, as up to that time industrial users choosing to use electricity generated their own. In the same month, the country's first renewable power was generated in a hydroelectric power plant operating on the Fox River in Appleton, Wisconsin. The plant, later named the Appleton Edison Light Company, was constructed by Appleton paper manufacturer H.J. Rogers, who had been inspired by Thomas Edison.

The modern utility system evolved in Chicago in 1892. When Samuel Insull, the British-born secretary of Thomas Edison arrived in Chicago in 1892 the town hosted more than twenty companies commercially producing electricity. Insull assumed the presidency of the small Chicago Edison company, one of many Edison franchises around the country. While Insull did not pioneer all of the early utility innovations, he was the first to combine all of the managerial and technological innovations that transformed the utility system into its modern company form.

Insull realized that his company could make more money by increasing what became known as the "load factor", the ratio of average daily or annual power load to the maximum load sustained during the same period. Insull installed equipment to meet the peak load of use during a day, typically in the evening when customers used electric lights. He understood that if he could find customers who would use electricity during off-peak times, he could increase income without additional capital expenditure. Those customers existed, but many generated power for themselves. He enticed customers such as street railway companies, ice houses, and other businesses by offering off-peak power for a lower cost than they incurred themselves.

Insull also exploited new technologies. During the late 1880s and 1890s, electricity was generated using reciprocating steam engines. Large, bulky, noisy, and hard to maintain, the reciprocating engines of the day converted up-and-down motion to rotary motion for use by electric generators through the use of a large flywheel. Steam turbines on the other hand, produced rotary motion directly, as steam passed through vanes on a long shaft. Much smaller in size, simpler mechanically, and quieter than reciprocating engines, steam turbines produced a greater amount of power from a smaller package. More importantly, the turbines could be scaled up to produce even more power with proportionally less investment in material, allowing a utility to produce electricity at an even lower unit cost. Insull ordered his first turbine-generator set from the General Electric Company in 1903, a 5 MW unit. Pleased with the unit's performance, he ordered a second 12 MW unit in 1911.

Unlike his former patron Edison, Insull was an early adaptor of Alternating Current (AC) generators and transformers. Developed in the 1880s, AC transformers overcame the technical limitation of transmitting low-voltage direct-current to distances beyond one mile. When power produced with already existing AC generators was transformed up to high voltages, current could flow for many miles without significant degradation. In 1896, Edison competitor Westinghouse Electric built a system of hydroelectric power plants at Niagara Falls that produced power for transmission to Buffalo, 20 miles away. The AC power illuminated lights, just like direct current, but more importantly, it powered the new AC motors that had recently come to market. AC motors, in turn became increasingly popular for their use in small electric appliances. These appliances not only increased overall power usage, they also helped spread power usage throughout the day, thus increasing utility load factors.

Finally, Insull also realized that competition in the electric power supply business would never allow him to effectively invest in the scalable turbine-generators and AC transmission systems he needed. To remedy the problem, Insull sought a monopoly position for his company. He took a two-step approach. The first step was to eliminate competition by acquiring the 20 other companies he competed with in Chicago. By 1907 he was the only remaining utility and he renamed the firm "Commonwealth Edison. The second step was to protect his monopoly position by aggressively supporting beneficial regulation.

The Regulated Power Monopoly

Modern regulation evolved during the Progressive era. At the heart of progressivism was a governmental acceptance of the notion that some industries constituted "natural monopolies." According to academic economists, industries like utilities required economies of scale in order to support the capital investment necessary for creating infrastructure and services. Municipal ownership and state regulation were the common methods for creating "natural monopolies". Progressives preferred state regulation. Wisconsin and New York pioneered regulation by establishing jurisdiction over the rates, schedules, service, and operations of their state's railroad companies. In July 1907, the Wisconsin legislature extended similar regulation to that state's electric utilities.

The Wisconsin Regulatory Commission compelled utilities to develop standard accounting techniques. It had the right to investigate the companies' books as part of the process for determining rates based on the physical valuation of a company's properties. Regulation, as viewed by its initiators, was intended to enforce the electric power companies' "obligation to serve" their customers. They were required to build infrastructure and serve all customers with as few interruptions as possible without discrimination. To fulfill their obligation, they needed to be able to raise capital and build plants to meet their projected loads. Utilities rates for service were based upon their operating costs plus their investments in equipment (the "base rate") plus a fair rate of return. In return, a utility company earned valuable rights. The most important right was the right to operate as a natural monopoly within its service territory. It also earned the right of eminent domain, formerly a power reserved by the state, so it could obtain property for its generating plants, transmission towers, and other equipment.

By 1914, state regulation had become standard and 44 states had established oversight of electric utilities using the Wisconsin model. Unlike railroad executives who resisted regulation, utility executives like Insull embraced the benefits. Regulation strongly supported electrification and infrastructure development. Investors knew that regulators not only oversaw the financial accounts of utilities (in an era before public disclosure of accounts was required) but also guaranteed a profit. Investments in utility companies were not as speculative as those in unregulated companies. Utilities were awarded high investment grade bond ratings. They could favorably raise money at attractive interest rates which reduced the costs of their capital projects. Regulators not only ensured that these project costs went into the utility rate base but also that generation and transmission assets were fully utilized. Eventually, regulators even allowed them to pass on-going project costs through to customers before the projects were actually completed, a practice known as Construction Work in Progress (CWIP).

Federal Government Involvement in the Power Industry

By 1940, all states had formed regulatory commissions with authority over their in-state utilities. Nevertheless, it was still not economical for private utilities to fully develop all available generation resources and provide complete electrification throughout the country. Under its interstate commerce mandate, the federal government became involved in the power industry for the first time in order to support the development of large hydropower generation facilities which were beyond the financial capability of even the largest utilities. The government developed and subsequently sold wholesale hydropower to utilities regardless of jurisdiction. In 1930 the Federal Power Commission (FPC), was established to coordinate such interstate federal hydropower development.

In 1933, the Tennessee Valley Authority was created as a federally owned corporation to provide electricity generation and economic development to the hard hit multi-state Appalachian region. In 1935, the federal government established the Rural Electrification Administration (REA) to provide electric power to the remote areas of the country previously not considered to be economically feasible to electrify. REA cooperatives pioneered the development and implementation of high voltage rural distribution networks. Today, most rural electrification is the product of locally owned rural electric cooperatives that got their start by securing government backed loans from the REA to build lines and provide service on a not-for-profit basis. REA funding is currently administered by the Department of Agriculture. That same year, under the Federal Power Act, the FPC was transformed into an independent regulatory agency and its authority was expanded to regulate both hydropower and interstate electricity transmission.

Growth and Transition

For over sixty years, state regulated electric power monopolies were successful in achieving the goal of national electrification. Unlike their regulated brethren in the transportation industry, power companies did not need to worry about competition from other forms of service. Indeed, few considered market alternatives. Power demand grew faster than GDP and technological advances, particularly more efficient large turbines and high voltage transformers, lowered the production costs for large generation plants while increasing the distance over which power could be economically transmitted. The industry became more capital intensive. Utility load planners, mindful of their dual mandate of low costs and reliable power planned and constructed large, efficient "base load" generating plants along with "peaking" plants for short duration use. In the Pacific Northwest, hydropower supplied both base load and peaking generation. The industry established an enviable record of successfully building and operating these ever larger generation plants. Most importantly, the prices for the industry's main fuels, coal and oil remained low and stable, allowing planners to comfortably build for the future.

The extended period of financial and business stability caused the industry to become highly dependent upon large "base load" generating plants for their business model. Unless generating capacity outstripped demand, regulated power utilities could operate their largest units at maximum capacity whenever they were available and be guaranteed a negotiated rate of return. In fact, the moment a shovel broke ground on most projects, they were already part of the rate base. This favorable environment ensured both a positive cash flow and a healthy return on invested capital. When coupled with the industries traditionally high credit rating, it also allowed utilities to confidently invest for the future. Unfortunately, it also made them extremely vulnerable to any disruption in the underlying factors that supported the business model, namely industry financial quality, stable fuel prices, technological change and the regulatory climate. Over the last forty years the industry has seen disruption in each of these four areas. It has responded with varying degrees of success. The story began, innocently enough as a response to the impending clean air legislation embodied in the Clean Air Act of 1970.

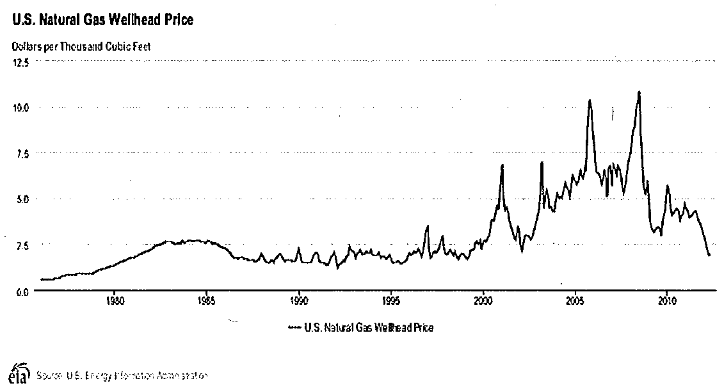
Disruption Leading to Deregulation and Restructuring

Anticipating the Clean Air Act and potential coal plant emission restrictions, low and stable crude oil prices in the late 1960's caused the industry to briefly shift its new construction base load emphasis from coal to cleaner burning petroleum-fired generation. The OPEC inspired oil price shock of 1973 created rising and unstable oil prices, questioning the wisdom of this shift. With environmental concerns threatening regulatory uncertainty in coal and global dependencies creating pricing instability in oil, the power industry was faced with potential disruption in their traditionally stable fuel supplies. There was wide industry interest in finding a stable and cost effective long term fuel source for large thermal power generation. Such a source appeared available in the form of nuclear power. With no apparent atmospheric pollutants and fuel costs that were a small percentage of the cost of generated power; nuclear provided an apparent economic and environmental advantage over coal and oil.

In the 1970's, power utilities made a major commitment to large base load nuclear power generation projects. Indeed, had all of the planned capacity been successfully deployed nuclear power today would be the largest single base load power source in the United States. Instead by the mid-1980s well over half of the planned nuclear plant projects were no longer viable due to a slowing rate of growth in electricity demand, significant cost and time overruns on projects, and increasingly complex regulatory requirements. Of the 249 nuclear power reactors originally ordered during this period, 120 were canceled and 26 were prematurely shut down. Even when successfully constructed, the technology proved to be operationally more complex than the industry was expecting. It took until the early 2000's for the overall capacity factor of the eventual nuclear fleet to reach acceptable levels. In making the transition to nuclear power, the industry faced significant financial and technological disruption.

It is difficult to overstate the impact this disruption had upon utilities, state regulators and the financial community. Regulators disallowed construction costs for failing base load power projects. Utilities could no longer automatically count on being reimbursed for their projects. In 1985, this action coupled with severe project cost overruns caused the financial industry to lower their recommendations for utility equity and reduce the credit ratings for the most heavily impacted utilities. The industry did not fully recover until the early 1990's. Many academic economists attributed this period of industry disruption to a concept termed "rate-of-return bias". They posited that not only does regulation cause utility companies to over-use capital during construction of their generating plants, but also when fuel costs become uncertain they tend to utilize that capital inefficiently. There was growing interest in the possibility of restructuring the power industry. The goal was the elimination of inefficient or unusable captive generating capacity, known as "stranded cost", and its replacement with competitively provided generation.

Power industry restructuring could not occur without deregulation. Deregulatory activity had already begun with Congress' attempt to forge an integrated energy policy in 1977 through the passage of the DOE Organization Act. This act consolidated various energy-related agencies into a Department of Energy (DOE). The following year, Congress passed the Public Utility Regulatory Policies Act (PURPA) of 1978 which opened the wholesale power markets to non-utilities. Prior to PURPA, utilities could utilize their monopoly status and refuse to interconnect or purchase power from non-utility generators at will. PURPA encouraged industrial power generation from waste heat ("cogeneration") by requiring utilities to purchase it at the "avoided cost" of building and operating their own plants. Congress also insisted that a separate independent regulatory body be retained, and accordingly the FPC was renamed the Federal Energy Regulatory Commission (FERC), preserving its independent status. FERC was asked to administer the new program described above.



Originally intended as a limited initiative to promote cogeneration and renewable power development, PURPA initiated a much broader set of changes. The industry consensus in the mid-seventies was that price controlled natural gas fueled generation would remain expensive, particularly relative to the average cost of the utility owned generation fleet. This was thought to make self-supply with natural gas burning generators uneconomic for most industrial users. Instead of remaining expensive however, the Natural Gas Policy Act of 1978 lifted the price controls on natural gas which had artificially reduced its supply and inflated its price since 1954. As decontrol of natural gas ended its artificial shortage, there was a dramatic reduction in natural gas prices. This trend lasted from 1980 through 2000 (see chart, above).

Technologically, newly developed combined cycle gas turbines rivaled and even exceeded the efficiency of the large steam turbines in use by the power industry. This overturned the prevailing wisdom that greater power generation efficiency could only be achieved through ever larger power plants. The power industry was now faced with additional regulatory and technological disruption. At the prevalent low gas prices, generators under 100 MW were as cheap to operate as coal or nuclear fired plants ten times their size. They had many operational advantages. They could be built quickly and cheaply, located where necessary and quickly amortized. They were flexibly capable of intermittent operation with minimal costs of regulation and environmental compliance. Distributed power provided by small gas turbines was a viable alternative to base load power. The Energy Policy Act of 1992 (EP Act) removed the final obstacle to supplier competition in the power market by allowing FERC to order transmission owners to carry power for other wholesale parties.

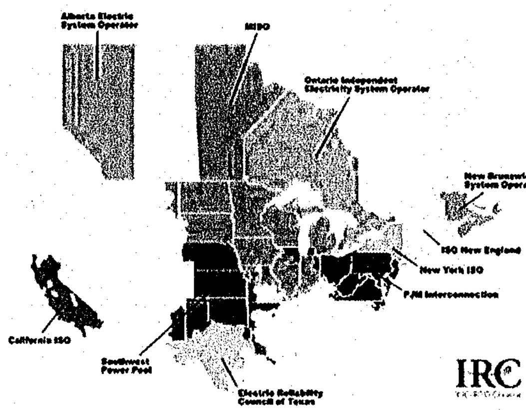
Throughout the latter portion of the 1980's and early 1990's both regulators and utilities in the largest power markets struggled to find stability amidst competition from natural gas and the increasing cost of power from large retail power plants caused by the fallout from the nuclear construction period, the rising cost of oil and the emission requirements being placed upon coal fired generators. Utilities were passing through the high costs of inefficient, un-built or delayed generation projects when at the same time they could often buy power more cheaply than they could produce it through the unregulated power exchanges arising under PURPA. If they could restructure, regulators felt they could direct their utilities to divest themselves of inefficient assets and cancel uncertain projects. Following the EP Act in 1992, many state regulators believed that the elimination of this barrier to entry, coupled with functioning, unregulated power exchanges created the conditions necessary for a smooth transition to a competitively restructured market. It was a position championed by ENRON.

In 1994, there was a second round of financial disruption in the power industry caused by the uncertainty created by PURPA and the EP Act. Utilities were now also open to a new business model. ENRON's delivered a message of unregulated power exchanges controlled by larger utilities wielding market power throughout the country. It was seductive. Larger utilities created unregulated "merchant" utility business units to competitively generate power. Between 1995 and 2001 state regulators directed their Investor Owned Utilities (IOUs) to divest themselves of 305 generating plants, comprising 156,000 MW or nearly 20% of all generating capacity in the country. About 75% of these divestitures went to the merchant utility subsidiaries of other IOUs. The non-utility generators (NUGs) supplying gas fired generation under PURPA and the merchant power subsidiaries of Investor Owned Utilities became known collectively as Independent Power Producers (IPPs). The combination of IPPs and power exchanges grew rapidly. From 1995 through 2005, utility purchases of unregulated power from IPPs grew more than twice as fast as the utilities own retail sales. In 1995, IPPs traded less than 8 million MW-h of electricity. By 1999 they were trading more than 1.5 billion MW-h of electricity.

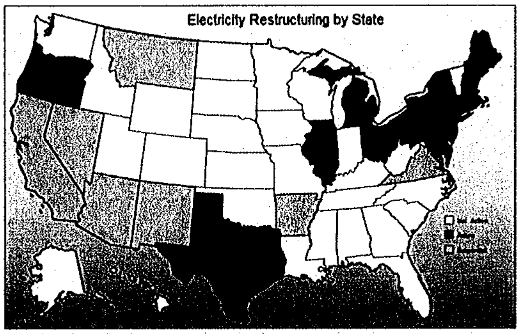
Power exchanges became the mechanism for delivering unregulated power. As more of the nation's power became supplied through these exchanges rather than through dedicated generation, the potential for retail price abuse increased. Retail users only had access to power through transmission and distribution owned by a single utility. High cost utilities could use their ownership position to abusively pass those costs through to the end user. Industrial and commercial users had self-generation options and high costs therefore fell disproportionately upon the retail user. It was becoming apparent that there was a need to standardize the unregulated wholesale power delivery structure. Consensus emerged regarding two areas of standardized structure: elimination of inefficient "stranded costs" and open access to transmission and distribution.

The issue came to a head in 2000 as a result of events in California. In 1998 California became the first state to attempt to provide retail choice through the elimination of inefficient stranded costs and the provision of open and transparent transmission access. In 2000 this initiative created a crisis when IPP's and natural gas fuel suppliers withheld or manipulated power and fuel in order to create artificial power shortages and increase short term power costs. ENRON (the power exchange operator) had orchestrated the abuse of poorly conceived power exchange rules in order to dramatically inflate costs, leading to the bankruptcy of the state's largest utility, Pacific Gas and Electric. In 2001, when ENRON failed as a business its manipulation along with the complicit actions of its power and fuel supply partners exposed the full scope of the potential for the abuse of power trading through unregulated power exchanges. Exchange operators around the country began to standardize and tightly control their operations, reducing the profitability of many of the merchant power providers. In 2002, the ENRON business failure subsequently led to bankruptcies and re-structuring in the merchant power sector, challenging the merchant power providers and exposing their utility counterparties. It created a third round of power industry financial disruption.

FERC had recognized that utility restructuring impacted interstate electricity transmission. Between 1996 and 1999 they issued standards for utilities to dispose of uneconomic assets by recovering their stranded costs. They also established a mechanism for transparent power pricing and control of transmission assets. They defined the voluntary role of an Independent System Operator (ISO) or Regional Transmission Organization (RTO) to provide non-discriminatory access to transmission and consistent operation and management over power exchanges. In order to level the playing field, the Energy Policy Act of 2005 also expanded FERC's authority to impose mandatory power availability and reliability standards on the bulk transmission system and impose penalties on entities that manipulate pricing in the electricity and natural gas markets. The California experience enhanced the role of the ISO's and RTO's as power exchange operators. Today, states that trade deregulated power through power exchanges operated by ISOs and RTOs serve 68% of the electricity consumers in the United States by volume (see chart, right); the remainder still receive some form of traditional cost-of-service regulated power.



In 1999 Texas passed the Texas Electric Restructuring Act, becoming the first state to successfully introduce a complete restructuring of its electric power market to promote competitive power delivery. Restructuring included open transmission, choice for the state's retail consumers and a requirement to fully eliminate the vertical integration common in regulated utilities. Texas' utilities were directed to unbundle their power generation, transmission and distribution, and retail electric services in the form of three separate (but possibly affiliated) companies. They were also directed to divest generation capacity to the point at which 40% or more of the residential and commercial customers in their former service areas were competitively served. Control over the state's transmission network was consolidated under the state's Regional Transmission Operator, ERCOT and retail electric customers were subsequently given choice in the selection of their power provider. Currently fifteen states and the District of Columbia have restructured electric power markets along the lines of the Texas model. This includes all large northeastern states, as well as Illinois, Ohio, Michigan, Oregon and Texas (see chart, left). These states comprise 50% of US retail power sales by volume. An additional seven states partially implemented restructuring but have subsequently suspended completion as a result of the California experience.



Both electric power deregulation and power industry restructuring were facilitated by the availability of low cost distributed power generated from inexpensive natural gas. Beginning in late 2000 natural gas prices began to rise and experience volatile price swings (see chart on page 5). From a stable price below \$2.50 per 000-ft^3, natural gas prices peaked at well over \$10 per 000-ft^3 prior to 2008. Since exchange pricing allows all qualified suppliers to sell power at the price established by the last selected bidder, high natural gas prices worked to the advantage of merchant power suppliers who owned coal or nuclear generation capability. By 2001, the nuclear fleet had begun to operate with a high level of utilization. Merchant power suppliers such as Exelon and Entergy that had focused primarily on the purchase of nuclear generation units at a significant discount were benefiting financially from higher power prices.

A combination of pent up utility demand, government financial incentives, the desire of international vendors to enter the US market and recently streamlined regulatory processes caused there to be a "nuclear renaissance". By 2009, the Nuclear Regulatory Commission had received applications for construction and operating licenses to build 25 new nuclear power reactors. Unfortunately, the case for widespread nuclear plant construction eroded fairly quickly. Natural gas prices fell as abundant supplies returned along with the concurrent issues of slow electricity demand and financing unavailability. Licenses were issued for four plants (not coincidentally in cost-of-service regulated states) while schedules for the remaining license applications were significantly extended, suspended or cancelled.

The cause of the newly abundant natural gas supply was the successful expansion of hydraulic fracturing ("fracking") to release natural gas trapped in shale rock formations. By 2011, natural gas prices had fallen below pre-2000 levels at nearly \$2.00 per 000-ft^3. Consequently, merchant nuclear and coal fired power began experiencing pricing pressures. Nearly half of all nuclear power falls into the merchant category along with a quarter of all coal fired power. There has been some rebound as by early 2013 natural gas prices reached \$4.00 per 000-ft^3. Many natural gas drillers have indicated that they do not intend to expand drilling of existing shale reserves until natural gas pricing becomes more favorable. The EIA projects that this "favorable" price will be in the range of \$4.00 to \$6.50 per 000-ft^3 over the next 20 years. Time will tell, but this is still a low price range for natural gas and should the EIA projection come to pass, the resultant situation creates an equilibrium scenario for the US economy that assures:

- Natural gas remains competitive with nuclear and most coal for electric power generation
- Renewable electric power generation becomes cost competitive with fewer subsidies
- LNG exports remain viable, including costs for liquefaction and transportation, and
- Industrial processes that require natural gas as a feed stock remain domestically viable

Nuclear advocates were not alone in assuming that rising natural gas prices would make traditional generation sources more attractive. From 2000 through 2008, there was a renewed financial interest in all forms merchant power, including the largest Leveraged Buyout in history in 2007. As a result, the return of low natural gas prices has also initiated an additional round of merchant power financial difficulties, bankruptcies and restructuring:

- **Exelon Corporation** stock fell over 7 percent when the PJM Interconnection announced that competitive bidding from external sources plus new natural gas power providers had produced a clearing price for future pricing of just \$59.37 per megawatt-day, about half of what analysts were forecasting and less than half of the \$136 per megawatt-day set in the 2015-16 future auctions. For Exelon, capacity revenue will fall about 41 percent in the year beginning June 1, 2016. After failing in an attempt to exempt its nuclear operations from Exchange bidding procedures, Exelon recently announced its intent to shut down its Clinton and Quad-Cities nuclear plants.
- **Energy Future Holdings** is undergoing restructuring under bankruptcy. The plan will restructure \$32B in debt in its Texas Competitive Holdings Business Unit with investors and creditors absorbing losses. Energy Future Holdings (the former Texas Utilities, Inc.) was the largest power supplier in Texas, created in 2007 as part of the largest leveraged buyout in history (\$47B). Note that this bankruptcy helps validate Texas' utility re-structuring model. Investors and creditors, rather than ratepayers are absorbing the results of poor business decisions.
- **Edison Mission Energy** (the merchant subsidiary of Southern California Edison) filed for bankruptcy protection in December of 2012 citing the costs necessary to bring its coal units into compliance with EPA Emissions requirements.
- **Dynegy,** an IPP has agreed to assume the Illinois coal and gas generation assets along with the debt of Ameren's merchant power subsidiary, **Ameren Genco**. Ameren, a Missouri utility has announced a re-structuring of **Ameren Genco** and will exit the merchant power business.

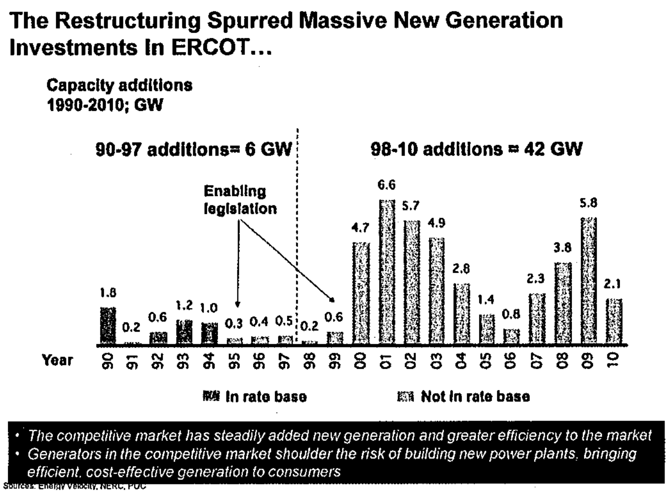
- **Dominion Resources** of Virginia is selling three fossil fueled merchant power plants in order to reduce the debt in its merchant power unit. Dominion is reducing debt to help cover the costs associated with the shutdown of its single unit Kewaunee Nuclear Plant in Wisconsin.

The Future of Deregulation and Restructuring

ENRON understood both the benefits of unregulated power exchanges along with their potential for abuse. When low cost power is available, an exchange offers the potential to acquire it at competitive prices with no risk of stranded costs. But an exchange can't overcome the realities of the existing generation and fuel supply infrastructure coupled with the complexity of a grid not optimized for exchange use. Even when the worst examples of abuse were eliminated, a lack of competitive generation alternatives has made it difficult to gain pricing advantage. Indeed, many complain that the bid system used to set power procurement policies actually causes exchange pricing to exceed regulated cost-of-service pricing. This is the primary criticism leveled by the American Public Power Association (the primary utility industry trade group).

The larger exchanges, such as the California ISO, The Electric Reliability Council of Texas and the PJM Interconnection (Mid-Atlantic) have been aggressive in implementing a series of initiatives designed to enhance exchange benefit and reduce overall power costs. California and Texas were early adopters of detailed grid modeling that allowed them to better monitor and predict their power needs and reduce or eliminate power shortages and grid congestion. PJM pioneered the development of Capacity Payments, a mechanism for contracting with power providers on a future basis to reserve power at an established price in order to eliminate short term pricing abuses. Detailed grid modeling and Capacity Payments (power price hedging in California) are now standard features of exchange operations and the results seem to reflect improved performance. The latest PJM Capacity auction incented a number of new bidders to offer power resulting in over a fifty percent reduction in the offered price.

Texas is the most aggressive proponent of a disciplined restructuring in order to create a competitive electric power market. In the opinion of the Texas legislature and service commission, a functioning power exchange, disaggregated generation, distribution and marketing and unrestricted consumer choice are all required in order to create the conditions necessary for competition. For nearly ten years, Texas struggled to enhance and adjust this model in order to bring down its retail prices. Eventually, their success in attracting new, competitively supplied generation paid off.



Texas Compared to the Rest of the Southeast

The chart on the left contrasts the recent performance of Texas and its restructured electric market with the seven other southeastern states, all of which are regulated cost-of-service states. As can be seen in the Independent Power Producer Column (IPP) on the left, nearly 70% of all power generated in Texas comes from providers classified as IPP's. Most of this power has been competitively sourced, as Texas has constructed over 42,000 MW of in-state generation since 2000 (see graphic, left). By way of contrast, over 87% of the power generated in the other seven southeastern states comes from conventional utility sources, all of which are currently part of the rate base of their utilities. In spite of the significantly lower stranded cost risk in Texas, the cost of retail power across the region is comparable and moderate with Texas at 10.89 cents/kw-h while the weighted average of the other seven is 10.55 cents/kw-h.

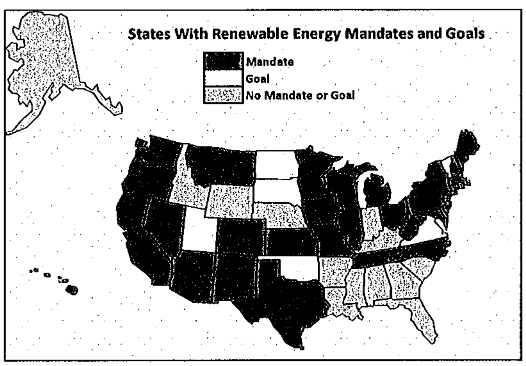
Selected Power Usage Data for January 2013: Texas vs. US Southeast Region (AR, LA, MS, AL, GA, SC, FL)

(All Data in cents/kw-hr or Thousands of MW-Hours)

	Res. Rates (cents/kw-h)	Power Providers(1/13 - MWh - 000)					Power Sources(1/13 - MWh - 000)			
		Tot	Util	IPP			Nucl	Coal	Nat Gas	Renew
TX	10.89	**33734**	**7047**	**23080**	**68.4%**		**2951**	**11733**	**15853**	**2734**
Pctg of Total							**8.7%**	**34.8%**	**47.0%**	**8.1%**
AR	8.74	5689	4109	1396	24.5%		1389	2718	1285	149
LA	8.76	8089	3730	1831	22.6%		959	1860	4344	228
MS	9.99	4041	2992	816	20.2%		311	463	3153	113
AL	10.84	12748	9515	2444	19.2%		3825	3573	3722	269
GA	10.25	10205	8836	942	9.2%		3045	3251	3412	284
SC	11.63	8316	8135	0	0.0%		5011	2095	919	154
FL	11.34	16220	14940	799	4.9%		2101	3262	10136	398
Wtd. Avg	**10.55**									
Total		**65308**	**52257**	**8228**	**12.6%**		**16641**	**17222**	**26971**	**1595**
Pctg of Total							**25.5%**	**26.4%**	**41.3%**	**2.4%**

Source: US Energy Information Administration (eia) - Electric Power Monthly with Data for January 2013

Energy from Renewable Sources



While not specifically a part of an unregulated or restructured power market, power from renewable sources is often included in any discussion of the transformation occurring in the power industry. Renewable power development has been significantly enhanced through Renewable Power Standards (RPS'). An RPS is a requirement for power suppliers to either procure or provide a certain minimum quantity of their total energy from renewable energy supply sources. Currently 29 states plus the District of Columbia have RPS' in the form of a goal or mandate (See chart, below).

RPS' vary widely, but generally renewable power is assumed to include power from wind, solar, biomass, hydro or geothermal sources. One state (Ohio) classifies nuclear as a renewable power source. The RPS establishes numeric targets for renewable energy supplies and seeks to encourage competition among renewable developers in meeting those targets in the least cost fashion possible. These targets are usually backed with some form of penalty if not met. Many RPS programs allow developers to utilize renewable energy certificates (REC's) to increase the flexibility and reduce the cost of compliance. Developers of non-conforming power supply projects can purchase REC's from developers that have an excess. REC's have become widespread in certain parts of the country and are electronically traded in Texas, New England, Wisconsin and within the PJM Interconnect (the Mid-Atlantic Regional Transmission Area). RPS' are designed to work in conjunction with other clean energy incentives, including federal and state clean energy tax incentives, renewable energy funds, and state integrated resource plans. California recently augmented their RPS with a cap and trade auction system for large carbon dioxide emitters.

Power industry disruption has overturned the orderly nature of this previously regulated industry and created a smorgasbord of overlapping structures. It is overly simplistic to think of power delivery in the form of regulated vs. unregulated states or traditional vs. restructured power markets. Many states are wrestling with seemingly contradictory structures. To pick just two of many examples, Oregon has chosen to become a restructured power market in order to introduce service provider competition and greater energy efficiency. They do not see the need for a power exchange given the stable nature of their hydropower. Florida, on the other hand is a traditional cost-of-service regulated state. Nevertheless, because of ratepayer dissatisfaction over the costs of failed power projects, their legislature requires cost disallowances in the case of failed, abandoned or over budget power projects. As in restructuring, this action shifts project risks from the ratepayers back to their utilities.

As was noted earlier, restructuring has created a two tier electric power industry where approximately 70% of the power consumed in the country flows through open transmission markets operated by ISOs or RTOs, while 30% is provided under the traditional cost-of-service regulated model. Restructuring has been in place for over ten years, which is a sufficient enough period of time to analyze the results and determine whether any trends are apparent.

States that opt for traditional regulation generally have experienced a lower than average cost of power and therefore do not have a "rate-of-return" bias. It is easier to justify large base load projects in these traditionally regulated states since there is a guarantee that the plant will be operated whenever it is available, that costs will be recovered and in some cases even that CWIP is available. States that opt for restructured power delivery generally have experienced a higher than average cost of power and have a strong "rate-of-return" bias. It is easier economically to provide flexible, distributed power generation in the restructured model. Perhaps nowhere in the country is it easier to see the distinction between the performance of the restructured electric power market and the regulated rate-of-return electric market than in the eight southeastern states of Texas, Arkansas, Louisiana, Mississippi, Alabama, Georgia, South Carolina and Florida. Texas was an early adopter of open transmission access via their RTO, ERCOT. It was also an early and aggressive adopter of retail choice and utilized an RPS in order to help create a major wind power infrastructure. Texas is one of the most complete examples of a state that has adopted a restructured electric market. All of the other seven southeastern states are strong proponents of the regulated rate-of-return model.

It is, however in the plans for future capacity addition where Texas' distributed generation concept contrasts most strikingly with the traditional planning model in use in the other seven states. In the latest twenty year plan reported by the Southeast Regional Reliability Planning entity (SERC), both Georgia and South Carolina reported that they had initiated construction on a total of 4900MW of new base load nuclear generation facilities. Florida reports future plans to build approximately 2500MW of new base load nuclear and across the region approximately 12,000MW of new gas generation and 1400MW of new coal generation is planned. In the aggregate 20,800 MW of new construction is planned all of it included in the rate base. No renewable generation is included in any part of the region.

In contrast, the Texas Regional Transmission Operator (ERCOT) has a very different plan. In the "*Long Term System Assessment for the ERCOT Region dated December 28, 2012*", ERCOT has developed six different business oriented electric power scenarios. In each scenario, up to 28,000 MW of new natural gas generation capability is paired with various combinations of wind, solar and geothermal power in order to provide for overall system reliability. Prominently noted in the ERCOT report is the following: "*The capital costs for pulverized coal, integrated gasification combined cycle, and nuclear units are too high for them to be competitive under the future scenarios evaluated*". ERCOT is planning the addition of around 50,000 to 70,000 MW of competitively supplied distributed generation. All the project risk is retained by the bidders and not the Texas electricity ratepayer. Further, since the individual Texas projects are relatively small and dispersed across a twenty year timeline, ERCOT retains the option, and indeed intends to modify its plans on an on-going basis as technology and business conditions change.

The future stakes are large; globally the power industry is the largest single industry in the world. In the United States alone it generates $737B in annual revenue and nearly 3% of GDP. As the industry and regulators attempt to come to grips with the issue of providing stable low cost retail power options, several significant changes have recently occurred that have the potential to significantly change the way power is generated in the United States.

The power industry is undergoing structural and technological transformation comparable to other large network oriented industries. Like the computer and telecommunications industries, power generation is becoming less centralized. Moderate natural gas prices make combined cycle gas turbine generators competitive with much larger thermal power generators. Automated metering has introduced two way communications between power suppliers and their customers, creating the opportunity for greater network monitoring efficiency and demand response management. PC's, and now smart phones and tablets enabled distributed information processing. "Point of sale" data capture allowed the retail industry to radically re-structure its distribution model, and centralized ticketing permitted the airline industry bypass the "hub-and-spoke" terminal model in favor of more efficient point-to-point routing based upon ticket price yield analysis. The fact that automated metering is introducing two way communications between power suppliers and their customers, creates the potential for greater customer driven power supply efficiency and service.

Lazard

Levelized Cost of Energy (LCOE) V.9.0

July 19, 2016

Albany Sustainability Committee
c/o Claire Griffing – Sustainability Coordinator

Thank you for the opportunity to comment on the draft "Technical Study for Community Choice Aggregation Program in Alameda County". My general impression is that the study is a through and fair-minded analysis of complex issues. This is no surprise: The primary contractor, MRW and Associates, is well-regarded by everyone I know in the electricity business. Below I suggest some minor additional work that may help in interpreting their results and assisting the discussion of the Alameda CCA.

- Include a historical comparison of electricity rates charged by PG&E and other CCAs. The expectation of lower rates was part of the appeal of each CCA. How has that worked out?
- For each scenario, include an estimate of the change in Greenhouse Gas emissions for the entire Northern California electricity sector, relative to the Base Case. In one scenario in the Technical Study, attribution of GHG emissions shifts from one entity to another, but there may be no overall reduction in emissions.
- Address in greater detail the operational concerns stated by the California Independent (Grid) Operator, or CAISO, regarding additions of solar electricity and possible curtailment of solar generators.
- Include two additional sensitivity cases on the assumed shutdown of the Diablo Canyon nuclear plant.

Each of these suggestions is described below. At the end, I present an analogy between the electricity grid and a tandem bicycle. I assume that people discussing the CCA understand how the grid works. However, newcomers (like me when I began work in the electric industry) may be assuming that the electricity grid works like Amazon or FedEx, e.g., I sign up for solar electricity and the grid delivers it to me. This is incorrect, and the correct view has policy implications.

Once again, thank you for the opportunity to comment.

Historical Comparison of CCA and PG&E Rates

Formation of each existing CCA was accompanied by an expectation of electricity rates lower than those charged by PG&E. How did that turn out? I was unable to find a comprehensive historical comparison. Instead, I found two snapshots. One shows what I expected: Sonoma Clean Energy's current monthly electricity bills are roughly 5% to 10% lower than those of PG&E. The other snapshot was surprising: Marin Clean Energy's bills are currently 5% to 10% higher than PG&E's. It would be helpful to have more than two data points.

Developing a complete historical comparison may be challenging, but MRW clearly has the expertise to do it, though it may require an addendum to the consulting contract.

> The comparisons of monthly bills are at these links:
> https://sonomacleanpower.org/wp-content/uploads/2015/11/2015-09-01-SCP_Joint-Rate-Comparison.pdf
> http://www.pge.com/includes/docs/pdfs/myhome/customerservice/energychoice/communitychoiceaggregation/mce_rateclasscomparison.pdf

GHG Emissions from Northern California's Electricity Sector

In the Technical Report, two scenarios appear to change the <u>attribution</u> of GHG emissions among different entities in Northern California, without major changes in total emissions from that sector. Adding estimates of electricity-sector GHG emissions to the Technical Study would clarify important results from Scenario 1 and Scenario 2.

For Scenario 1, the Technical Study states that:

> "there are no greenhouse benefits for Scenario 1 [for the Alameda CCA]—in fact there are net incremental emissions" (p. vii).

This statement seems unduly pessimistic. It appears that in Scenario 1, customers leaving PG&E to join the Alameda CCA are no longer credited with a share of PG&E's GHG-free electricity (hydro and nuclear), but there is no change in overall emissions.

In Scenario 1, the Alameda CCA meets 33% of its customers' demand with renewables, and meets the other 67% with purchases of non-renewable electricity from the wholesale market. This treatment increases the GHG emissions attributed to the customers who leave PG&E to join the Alameda CCA, because they are no longer credited with shares of PG&E's GHG-free electricity. However, Alameda's purchases of non-renewable electricity are offset by reduced purchases by PG&E, because it has fewer customers than in the Base Case.

A similar observation applies to Scenario 2, where it is more important. The Technical Study notes that

> "The Alameda CCA's GHG emissions under Scenario 2 are much lower than those under Scenario 1. This is due to the higher renewable content in the CCA's generation mix under Scenario 2, but <u>more importantly</u>, the 50% hydro content in the non-renewable generation mix." (p. vii, emphasis added)

In other words, the Alameda CCA has lower GHG emissions in Scenario 2 than in the Base Case or Scenario 1 partly because it builds or pays for construction of more GHG-free generators. This is "steel in the ground", and causes a drop in the GHG emissions of the Northern California electricity sector. So far, so good, but how about that more important part--the "50% hydro content in the non-renewable generation mix".

To the best of my knowledge, all of California's good sites for hydroelectric generators are already being used, so new hydro is not an option. The Technical Study may be assuming that, when an existing contract to sell hydroelectricity expires, the Alameda CCA will outbid other CCAs and utilities to sign a new contract in order to achieve "50% hydro content". This is how I interpret the statement in the Technical Study that "if carbon reductions are a high priority for the CCA, a concerted effort to contract with hydroelectric or other carbon-free generators would be needed" (p. xiii).

If my interpretation is correct, Scenario 2 assumes that the Alameda CCA would outbid competitors for electricity from existing hydroelectric plants. Outbidding would change the allocation of GHG emissions among parties in Northern California, without any change in the total GHG emissions.

It seems reasonable to assume aggressive bidding by many entities for hydroelectricity when current contracts expire. The Alameda CCA could be trying to outbid the Marin and Sonoma CCAs and utilities including PG&E, the Sacramento Municipal Utility District, Palo Alto, Modesto, Turlock and others

CAISO's Operational Concerns

The California Independent [Transmission] System Operator, or CAISO, has repeatedly expressed concern about its ability to provide reliable service due to operational difficulties caused by increasing additions of solar generators. This concern may be relevant to the Alameda CCA because CAISO can address it partly by forcibly "curtailing", or disconnecting solar PV from the grid.

The CAISO's concern is complicated and hard to explain, and even harder to analyze. Here is a description by the National Renewable Energy Laboratory of the CAISO's concern:

> "In 2013, the California Independent System Operator (CAISO) published a chart showing the potential for "overgeneration" occurring at increased penetration of solar photovoltaics (PV). The "duck chart"[2] shows the potential for PV to provide more energy than can be used by the system, especially considering the host of technical and institutional constraints on power system operation.
>
> During overgeneration conditions, the supply of power could exceed demand, and without intervention, generators and certain motors connected to the grid would increase rotational speed, which can cause damage. To avoid this, system operators carefully balance supply with demand, increasing and reducing output from the conventional generation fleet. The overgeneration risk occurs when conventional dispatchable resources cannot be backed down further to accommodate the supply of variable generation (VG). Overgeneration has a relatively simple technical solution,

often referred to as curtailment. Curtailment occurs when a system operator decreases the output from a wind or PV plant below what it would normally produce."

Source: "Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart", November 2015, at http://www.nrel.gov/docs/fy16osti/65023.pdf

The Technical Study may not directly address the CAISO's concern. The Study does address hours when the Alameda CCA's renewable generators produce more electricity than its customers are using (pp. 11-12 and Appendix B-3), but it's not clear whether that approach addresses the problem at the grid level. If the Alameda CCA and other entities collectively build "too much" solar PV, the CAISO may accommodate electricity from Alameda's PV units by curtailing PV units owned by other entities.

I suggest that the Technical Study examine the possibility of curtailment of solar PV units, whether owned by the Alameda CCA or other entities. Curtailment might be a problem, especially if Alameda pursues a 100% renewable portfolio based largely on solar PV.

Sensitivity Study: Replacement of Diablo Canyon Nuclear Power Plant

The Technical Study assumes that PG&E retires Diablo Canyon Units 1 and 2 when their operating licenses expire in 2024 and 2025. The Technical Study apparently assumes that PG&E replaces Diablo with GHG-emitting electricity:

> The expected retirement of Diablo Canyon in 2025 increases PG&E's emissions by approximately 30% in 2025. (p. vii)

Would it be reasonable to include a sensitivity case in which PG&E replaces Diablo with renewable sources? Such a sensitivity case would presumably raise the Study's forecast of PG&E rates and cut its forecast of PG&E's GHG. It would be useful to see quantitative results.

Sensitivity Study: Extension of Diablo Canyon Operation

To justify the assumed retirement, the Technical Study cites several costs, notably a cost of $4.5 billion cost to install cooling towers "per state regulations implementing the Federal Clean Water Act" (p. C-3). This assumption is included in the Base Case and Scenarios 1 and 2, and clearly it deserves that treatment. Is it conceivable, however, that the impacts of climate change over the next several years cause a shift in public opinion and the law to promote relicensing? Would it be reasonable to perform a sensitivity case in which PG&E's cost to relicense Diablo is, say, $1 billion because of a change in the law?

Tandem Bicycle Analogy to the Electricity Grid:

Newcomers to electricity issues sometimes assume (as I once did) that the electricity grid works like Amazon or FedEx: I order a parcel of, say, electricity from solar panels, and, supposedly, it is delivered through the grid to my house. The reality is more complicated, and has policy implications. The analogy between the electricity grid and a tandem bicycle may help.

Imagine a long tandem bicycle, with many seats, ascending a long, even grade. Suppose that it must be kept ascending at a constant speed (e.g., because traveling faster or slower would cause excessive vibration). Some people (representing generators) are pushing on their pedals, providing mechanical energy to propel the bicycle. Others are passengers (representing demand or "load") who are free to jump on or off.

As passengers jump on or off, the pedalers must collectively adjust how hard they press on the pedals to keep the bicycle moving at a constant speed. If one pedaler suddenly stops pressing on the pedals, others have to press harder to maintain a constant speed.

Now suppose that new pedalers are added, but the new pedalers push hard on the pedals only when the sun breaks through the clouds. At those sunny times the other pedalers have to push lightly on the pedals, or not at all, to prevent the bicycle from achieving excessive speed.

In the terms of this analogy, the CAISO's operating concern is that, as more solar "pedalers" are added, their pedaling occasionally overwhelms the collective ability of other pedalers to back off. One solution is curtailment of the solar pedalers: The CAISO disconnects some pedals from the tandem bicycle's chain, thereby wasting some potential renewable electricity and not realizing its environmental benefits.

Thank you for considering these comments.

Sincerely,
Mark Meldgin
Albany CA

Notes:

1. The draft Technical Study and draft Appendices are at the following links: https://www.acgov.org/cda/planning/cca/documents/Feas-TechAnalysisDRAFT5312016.pdf and https://www.acgov.org/cda/planning/cca/documents/Feas-TechStudyappendices05312016.pdf
2. The tandem-bicycle analogy is presented in greater detail, aimed at an engineering audience, at this site: http://www.leonardo-energy.org/sites/leonardo-energy/files/root/Documents/2009/ElectricityTandem.pdf

Rivera, Sandra, CDA

Subject: FW: IBEW comments - MRW Work Papers

From: Stern, Hunter [mailto:hls5@IBEW1245.com]
Sent: Saturday, June 18, 2016 7:01 PM
To: Rivera, Sandra, CDA <sandra.rivera@acgov.org>; Jensen, Bruce, CDA <bruce.jensen@acgov.org>; 'mef@mrwassoc.com' <mef@mrwassoc.com>
Cc: 'Uno, Victor' <Victor_Uno@IBEW.org>
Subject: RE: IBEW comments - MRW Work Papers

Sandra,

Again thanks for the extra hours to submit these comments. More importantly, thanks to the County and MRW for making these Work-Papers available for review. This has given clear insight into the information contained MRW draft report and updated draft.

The "Big Picture" take away from these Work Papers is that the MRW Technical-Feasibility report errs in its approach and analysis. Partly, there is inadequate or missing documentation that does not substantiate the information and apparent conclusions made by the Report. But the fundamental error is the approach.

The MRW report is no more than a single snapshot of a series of single predictions regarding future PG&E rates, future cost of solar power, future cost of power from local renewable projects and numerous other distinct data points. In fact, these data points are, in most cases, no better than 'guesses and the resultant conclusions are entirely unreliable. The failure of this review and others associated with decisions to launch Community Choice Aggregation public agencies in Marin, Sonoma and San Mateo is that the Technical-Feasibility report relies on unsubstantiated estimates as if they are fact and then concludes to advise Alameda County that the CCE will be successful and should launch.

In fact, a proper Technical-Feasibility report should be made via Probability Analysis. Probability Analysis can take the variables of the needed data points, utilize these variants to include the likely value of each data point and then combine these probabilities to create an accurate determination of the likelihood that an Alameda CCE will achieve the desired objectives. The IBEW strongly urges that the Peer Review of the MRW Study include Probability Analysis of the information gathered by MRW as well as including the information missing which is needed to complete the analysis.

Here are specific comments on the Work Papers:

1. MRW uses Sonoma Clean Power (SCP) data for base A&G assumptions yet SCP has not met its promises/expectations of high RPS content (SCP has only 33% RPS), has not built any local projects (that I know of), and is in a dead heat with PG&E rates. Further, SCP was caught completely off guard by the PCIA increase, which, with adequate technical assistance, SCP should have been able to predict. Unless Alameda wants a track record like SCP, SCP A&G assumptions are not reliable.
2. "Admin Costs" at tab "Detail" F7-F11 states "these are just guess/placeholders" for $1.2mm in Admin Costs. On what basis is this guess made? Marin Clean Energy (MCE) has claimed as much as $2.5 Million in start-up costs. San Joaquin Valley Power Authority spent more than $2 Million. SCP has never discussed their costs but as the planning and project work was done by the Sonoma County Water Agency and they reportedly spent $1.5 million in its work. How can this be a guess and why use $1.2 Million. Given that the County has contracted for this work, we should expect more than guesses and placeholders for costs in the millions.

3. "PG&E Rate Model" at tab "PG&E Capacity Forecast" B10 states "Note: CPUC's October 2015 Scenario Tool in Long Term Procurement Proceeding (R.13-12-010) shows total system supply of 115.4% of system demand in 2035; we have assumed that new capacity will therefore be needed beginning in 2036 and that the tight capacity supply will begin to increase capacity prices in 2030" The presumptive impact of this assumption is that PG&E will pay more for capacity in 2030, but is that applied to CCA too? If so, where is it applied in the MRW analysis and how? If not, why? Besides, there is reason to believe this information is inaccurate. Most experts believe the push for increased renewable energy under SB350 will drive a need for more flexible capacity to replace baseload capacity, not necessarily increase capacity prices in general.
4. The Pro Forma assumes 15% opt outs. On what basis? MCE had its customers opt-out at over 20% rate for its first few years and has trended toward 25%. SCP has had its customers thus far trend to 15% opt-out rate. (Without any information that SCP is not achieving all its objectives. In short, a 20% Opt-Out rate should be the rule of thumb for essential service default programs.
5. We need further direction or clarity on the information MRW used to calculate greenhouse emission rates. We can't find specific information in the Work Papers that would substantiate the estimates given. Specifically, what is the baseload portfolio mix on non-renewable power that was used?
6. Previously, the IBEW questioned the voracity of the wind and solar future costs. We cannot find the basis of these estimates unless MRW has included the use of unbundled RECs, reducing the overall power costs.

Please advise as to the information MRW used for projected GHG emissions rates and whether the use of unbundled RECs are part of the analysis and in what amount.

Kind Regards,

Hunter Stern
IBEW Local 1245

East Bay Community Energy Authority

- Joint Powers Agreement –

Effective ____________

Among The Following Parties:

EAST BAY COMMUNITY ENERGY AUTHORITY

JOINT POWERS AGREEMENT

This Joint Powers Agreement ("Agreement"), effective as of _________, is made and entered into pursuant to the provisions of Title 1, Division 7, Chapter 5, Article 1 (Section 6500 *et seq.*) of the California Government Code relating to the joint exercise of powers among the parties set forth in Exhibit A ("Parties"). The term "Parties" shall also include an incorporated municipality or county added to this Agreement in accordance with Section 3.1.

RECITALS

1. The Parties are either incorporated municipalities or counties sharing various powers under California law, including but not limited to the power to purchase, supply, and aggregate electricity for themselves and their inhabitants.

2. In 2006, the State Legislature adopted AB 32, the Global Warming Solutions Act, which mandates a reduction in greenhouse gas emissions in 2020 to 1990 levels. The California Air Resources Board is promulgating regulations to implement AB 32 which will require local government to develop programs to reduce greenhouse gas emissions.

3. The purposes for the Initial Participants (as such term is defined in Section 1.1.16 below) entering into this Agreement include securing electrical energy supply for customers in participating jurisdictions, addressing climate change by reducing energy related greenhouse gas emissions, promoting electrical rate price stability, and fostering local economic benefits such as jobs creation, community energy programs and local power development. It is the intent of this Agreement to promote the development and use of a wide range of renewable energy sources and energy efficiency programs, including but not limited to State, regional and local solar and wind energy production.

4. The Parties desire to establish a separate public agency, known as the East Bay Community Energy Authority ("Authority"), under the provisions of the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq.*) ("Act") in order to collectively study, promote, develop, conduct, operate, and manage energy programs.

5. The Initial Participants have each adopted an ordinance electing to implement through the Authority a Community Choice Aggregation program pursuant to California Public Utilities Code Section 366.2 ("CCA Program"). The first priority of the Authority will be the consideration of those actions necessary to implement the CCA Program.

6. By establishing the Authority, the Parties seek to:

   (a) Provide electricity rates that are lower or competitive with those offered by PG&E for similar products;

(b) Offer differentiated energy options (e.g. 33% or 50% qualified renewable) for default service, and a 100% renewable content option in which customers may "opt-up" and voluntarily participate;

(c) Develop an electric supply portfolio with a lower greenhouse gas (GHG) intensity than PG&E, and one that supports the achievement of the parties' greenhouse gas reduction goals and the comparable goals of all participating jurisdictions;

(d) Establish an energy portfolio that prioritizes the use and development of local renewable resources and minimizes the use of unbundled renewable energy credits;

(e) Promote an energy portfolio that incorporates energy efficiency and demand response programs and has aggressive reduced consumption goals;

(f) Demonstrate quantifiable economic benefits to the region (e.g. union and prevailing wage jobs, local workforce development, new energy programs, and increased local energy investments);

(g) Recognize the value of workers in existing jobs that support the energy infrastructure of Alameda County and Northern California. The Authority, as a leader in the shift to a clean energy, commits to ensuring it will take steps to minimize any adverse impacts to these workers to ensure a "just transition" to the new clean energy economy;

(h) Deliver clean energy programs and projects using a stable, skilled workforce through such mechanisms as project labor agreements, or other workforce programs that are cost effective, designed to avoid work stoppages, and ensure quality;

(i) Promote personal and community ownership of renewable resources, spurring equitable economic development and increased resilience, especially in low income communities;

(j) Provide and manage lower cost energy supplies in a manner that provides cost savings to low-income households and promotes public health in areas impacted by energy production; and

(k) Create an administering agency that is financially sustainable, responsive to regional priorities, well managed, and a leader in fair and equitable treatment of employees through adopting appropriate best practices employment policies, including, but not limited to, promoting efficient consideration of petitions to unionize, and providing appropriate wages and benefits.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual promises, covenants, and conditions hereinafter set forth, it is agreed by and among the Parties as follows:

ARTICLE 1
CONTRACT DOCUMENTS

1.1 Definitions. Capitalized terms used in the Agreement shall have the meanings specified below, unless the context requires otherwise.

1.1.1 "AB 117" means Assembly Bill 117 (Stat. 2002, ch. 838, codified at Public Utilities Code Section 366.2), which created CCA.

1.1.2 "Act" means the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq.*)

1.1.3 "Agreement" means this Joint Powers Agreement.

1.1.4 "Annual Energy Use" has the meaning given in Section 1.1.23.

1.1.5 "Authority" means the East Bay Community Energy Authority established pursuant to this Joint Powers Agreement.

1.1.6 "Authority Document(s)" means document(s) duly adopted by the Board by resolution or motion implementing the powers, functions and activities of the Authority, including but not limited to the Operating Rules and Regulations, the annual budget, and plans and policies.

1.1.7 "Board" means the Board of Directors of the Authority.

1.1.8 "Community Choice Aggregation" or "CCA" means an electric service option available to cities and counties pursuant to Public Utilities Code Section 366.2.

1.1.9 "CCA Program" means the Authority's program relating to CCA that is principally described in Sections 2.4 and 5.1.

1.1.10 "Days" shall mean calendar days unless otherwise specified by this Agreement.

1.1.11 "Director" means a member of the Board of Directors representing a Party, including an alternate Director.

1.1.12 "Effective Date" means the date on which this Agreement shall become effective and the East Bay Community Energy Authority shall exist as a separate public agency, as further described in Section 2.1.

1.1.13 "Ex Officio Board Member" means a non-voting member of the Board of Directors as described in Section 4.2.2. The Ex Officio Board Member may not serve on the Executive Committee of the Board or participate in closed session meetings of the Board.

1.1.14 "Implementation Plan" means the plan generally described in Section 5.1.2 of this Agreement that is required under Public Utilities Code Section 366.2 to be filed with the California Public Utilities Commission for the purpose of describing a proposed CCA Program.

1.1.15 "Initial Costs" means all costs incurred by the Authority relating to the establishment and initial operation of the Authority, such as the hiring of a Chief Executive Officer and any administrative staff, any required accounting, administrative, technical and legal services in support of the Authority's initial formation activities or in support of the negotiation, preparation and approval of power purchase agreements. The Board shall determine the termination date for Initial Costs.

1.1.16 "Initial Participants" means, for the purpose of this Agreement the County of Alameda, the Cities of Albany, Berkeley, Emeryville, Oakland, Piedmont, San Leandro, Hayward, Union City, Newark, Fremont, Dublin, Pleasanton and Livermore.

1.1.17 "Operating Rules and Regulations" means the rules, regulations, policies, bylaws and procedures governing the operation of the Authority.

1.1.18 "Parties" means, collectively, the signatories to this Agreement that have satisfied the conditions in Sections 2.2 or 3.1 such that it is considered a member of the Authority.

1.1.19 "Party" means, singularly, a signatory to this Agreement that has satisfied the conditions in Sections 2.2 or 3.1 such that it is considered a member of the Authority.

1.1.20 "Percentage Vote" means a vote taken by the Board pursuant to Section 4.12.1 that is based on each Party having one equal vote.

1.1.21 "Total Annual Energy" has the meaning given in Section 1.1.23.

1.1.22 "Voting Shares Vote" means a vote taken by the Board pursuant to Section 4.12.2 that is based on the voting shares of each Party described in Section 1.1.23 and set forth in Exhibit C to this Agreement. A Voting Shares vote cannot take place on a matter unless the matter first receives an affirmative or tie Percentage Vote in the manner required by Section 4.12.1 and three or more Directors immediately thereafter request such vote.

1.1.23 "Voting Shares Formula" means the weight applied to a Voting Shares Vote and is determined by the following formula:

(Annual Energy Use/Total Annual Energy) multiplied by 100, where (a) "Annual Energy Use" means (i) with respect to the first two years following the Effective Date, the annual electricity usage, expressed in kilowatt hours ("kWh"), within the Party's respective jurisdiction and (ii) with respect to the period after the second anniversary of the Effective Date, the annual electricity usage, expressed in kWh, of accounts within a Party's respective jurisdiction that are served by the Authority and (b) "Total Annual Energy" means the sum of all Parties' Annual Energy Use. The initial values for Annual Energy use are designated in Exhibit B and the initial voting shares are designated in Exhibit C. Both Exhibits B and C shall be adjusted annually as soon as reasonably practicable after January 1, but no later than March 1 of each year subject to the approval of the Board.

1.2 **<u>Documents Included</u>**. This Agreement consists of this document and the following exhibits, all of which are hereby incorporated into this Agreement.

Exhibit A: List of the Parties

Exhibit B: Annual Energy Use

Exhibit C: Voting Shares

1.3 **<u>Revision of Exhibits</u>**. The Parties agree that Exhibits A, B and C to this Agreement describe certain administrative matters that may be revised upon the approval of the Board, without such revision constituting an amendment to this Agreement, as described in Section 8.4. The Authority shall provide written notice to the Parties of the revision of any such exhibit.

ARTICLE 2
FORMATION OF EAST BAY COMMUNITY ENERGY AUTHORITY

2.1 **<u>Effective Date and Term</u>**. This Agreement shall become effective and East Bay Community Energy Authority shall exist as a separate public agency on December 1, 2016, provided that this Agreement is executed on or prior to such date by at least three Initial Participants after the adoption of the ordinances required by Public Utilities Code Section 366.2(c)(12). The Authority shall provide notice to the Parties of the Effective Date. The Authority shall continue to exist, and this Agreement shall be effective, until this Agreement is terminated in accordance with Section 7.3, subject to the rights of the Parties to withdraw from the Authority.

2.2 **Initial Participants**. Until December 31, 2016, all other Initial Participants may become a Party by executing this Agreement and delivering an executed copy of this Agreement and a copy of the adopted ordinance required by Public Utilities Code Section 366.2(c)(12) to the Authority. Additional conditions, described in Section 3.1, may apply (i) to either an incorporated municipality or county desiring to become a Party that is not an Initial Participant and (ii) to Initial Participants that have not executed and delivered this Agreement within the time period described above.

2.3 **Formation**. There is formed as of the Effective Date a public agency named the East Bay Community Energy Authority. Pursuant to Sections 6506 and 6507 of the Act, the Authority is a public agency separate from the Parties. The debts, liabilities or obligations of the Authority shall not be debts, liabilities or obligations of the individual Parties unless the governing board of a Party agrees in writing to assume any of the debts, liabilities or obligations of the Authority. A Party who has not agreed to assume an Authority debt, liability or obligation shall not be responsible in any way for such debt, liability or obligation even if a majority of the Parties agree to assume the debt, liability or obligation of the Authority. Notwithstanding Section 8.4 of this Agreement, this Section 2.3 may not be amended unless such amendment is approved by the governing boards of all Parties.

2.4 **Purpose**. The purpose of this Agreement is to establish an independent public agency in order to exercise powers common to each Party and any other powers granted to the Authority under state law to participate as a group in the CCA Program pursuant to Public Utilities Code Section 366.2(c)(12); to study, promote, develop, conduct, operate, and manage energy and energy-related climate change programs; and, to exercise all other powers necessary and incidental to accomplishing this purpose.

2.5 **Powers**. The Authority shall have all powers common to the Parties and such additional powers accorded to it by law. The Authority is authorized, in its own name, to exercise all powers and do all acts necessary and proper to carry out the provisions of this Agreement and fulfill its purposes, including, but not limited to, each of the following:

2.5.1 to make and enter into contracts, including those relating to the purchase or sale of electrical energy or attributes thereof;

2.5.2 to employ agents and employees, including but not limited to a Chief Executive Officer and General Counsel;

2.5.3 to acquire, contract, manage, maintain, and operate any buildings, works or improvements, including electric generating facilities;

2.5.4 to acquire property by eminent domain, or otherwise, except as limited under Section 6508 of the Act, and to hold or dispose of any property;

2.5.5 to lease any property;

2.5.6 to sue and be sued in its own name;

2.5.7 to incur debts, liabilities, and obligations, including but not limited to loans from private lending sources pursuant to its temporary borrowing powers such as Government Code Section 53850 *et seq*. and authority under the Act;

2.5.8 to form subsidiary or independent corporations or entities, if appropriate, to carry out energy supply and energy conservation programs at the lowest possible cost consistent with the Authority's CCA Program implementation plan, risk management policies, or to take advantage of legislative or regulatory changes;

2.5.9 to issue revenue bonds and other forms of indebtedness;

2.5.10 to apply for, accept, and receive all licenses, permits, grants, loans or other assistance from any federal, state or local public agency;

2.5.11 to submit documentation and notices, register, and comply with orders, tariffs and agreements for the establishment and implementation of the CCA Program and other energy programs;

2.5.12 to adopt rules, regulations, policies, bylaws and procedures governing the operation of the Authority ("Operating Rules and Regulations");

2.5.13 to make and enter into service, energy and any other agreements necessary to plan, implement, operate and administer the CCA Program and other energy programs, including the acquisition of electric power supply and the provision of retail and regulatory support services; and

2.5.14 to negotiate project labor agreements, community benefits agreements and collective bargaining agreements with the local building trades council and other interested parties.

2.6 **Limitation on Powers**. As required by Government Code Section 6509, the power of the Authority is subject to the restrictions upon the manner of exercising power possessed by the City of Emeryville and any other restrictions on exercising the powers of the Authority that may be adopted by the Board.

2.7 **Compliance with Local Zoning and Building Laws**. Notwithstanding any other provisions of this Agreement or state law, any facilities, buildings or structures located, constructed or caused to be constructed by the Authority within the territory of the Authority shall comply with the General Plan, zoning and building laws of the local jurisdiction within which the facilities, buildings or structures are constructed and comply with the California Environmental Quality Act ("CEQA").

2.8 **Compliance with the Brown Act**. The Authority and its officers and employees shall comply with the provisions of the Ralph M. Brown Act, Government Code Section 54950 *et seq*.

2.9 **Compliance with the Political Reform Act and Government Code Section 1090.** The Authority and its officers and employees shall comply with the Political Reform Act (Government Code Section 81000 *et seq.*) and Government Code Section 1090 *et seq*, and shall adopt a Conflict of Interest Code pursuant to Government Code Section 87300. The Board of Directors may adopt additional conflict of interest regulations in the Operating Rules and Regulations.

ARTICLE 3
AUTHORITY PARTICIPATION

3.1 **Addition of Parties**. Subject to Section 2.2, relating to certain rights of Initial Participants, other incorporated municipalities and counties may become Parties upon (a) the adoption of a resolution by the governing body of such incorporated municipality or county requesting that the incorporated municipality or county, as the case may be, become a member of the Authority, (b) the adoption by an affirmative vote of a majority of all Directors of the entire Board satisfying the requirements described in Section 4.12, of a resolution authorizing membership of the additional incorporated municipality or county, specifying the membership payment, if any, to be made by the additional incorporated municipality or county to reflect its pro rata share of organizational, planning and other pre-existing expenditures, and describing additional conditions, if any, associated with membership, (c) the adoption of an ordinance required by Public Utilities Code Section 366.2(c)(12) and execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership fee, if any, and (e) satisfaction of any conditions established by the Board.

3.2 **Continuing Participation**. The Parties acknowledge that membership in the Authority may change by the addition and/or withdrawal or termination of Parties. The Parties agree to participate with such other Parties as may later be added, as described in Section 3.1. The Parties also agree that the withdrawal or termination of a Party shall not affect this Agreement or the remaining Parties' continuing obligations under this Agreement.

ARTICLE 4
GOVERNANCE AND INTERNAL ORGANIZATION

4.1 **Board of Directors**. The governing body of the Authority shall be a Board of Directors ("Board") consisting of one director for each Party appointed in accordance with Section 4.2.

4.2 **Appointment of Directors**. The Directors shall be appointed as follows:

4.2.1 The governing body of each Party shall appoint and designate in writing one regular Director who shall be authorized to act for and on behalf of the Party on matters within the powers of the Authority. The governing body of each Party also shall appoint and designate in writing one alternate Director who may vote on matters when the regular Director is absent from a Board meeting. The person appointed and designated as the regular Director shall be a member of the governing body of the Party. The person appointed and designated as the alternate Director shall also be a member of the governing body of the Party.

4.2.2 The Board shall also include one non-voting ex officio member as defined in Section 1.1.13 ("Ex Officio Board Member"). The Chair of the Community Advisory Committee, as described in Section 4.9 below, shall serve as the Ex Officio Board Member. The Vice Chair of the Community Advisory Committee shall serve as an alternate Ex Officio Board Member when the regular Ex Officio Board Member is absent from a Board meeting.

4.2.3 The Operating Rules and Regulations, to be developed and approved by the Board in accordance with Section 2.5.12 may include rules regarding Directors, such as meeting attendance requirements. No Party shall be deprived of its right to seat a Director on the Board.

4.3 **Terms of Office**. Each regular and alternate Director shall serve at the pleasure of the governing body of the Party that the Director represents, and may be removed as Director by such governing body at any time. If at any time a vacancy occurs on the Board, a replacement shall be appointed to fill the position of the previous Director in accordance with the provisions of Section 4.2 within 90 days of the date that such position becomes vacant.

4.4 **Quorum**. A majority of the Directors of the entire Board shall constitute a quorum, except that less than a quorum may adjourn a meeting from time to time in accordance with law.

4.5 **Powers and Function of the Board**. The Board shall conduct or authorize to be conducted all business and activities of the Authority, consistent with this Agreement, the Authority Documents, the Operating Rules and Regulations, and applicable law. Board approval shall be required for any of the following actions, which are defined as "Essential Functions":

4.5.1 The issuance of bonds or any other financing even if program revenues are expected to pay for such financing.

4.5.2 The hiring of a Chief Executive Officer and General Counsel.

4.5.3 The appointment or removal of an officer.

4.5.4 The adoption of the Annual Budget.

4.5.5 The adoption of an ordinance.

4.5.6 The initiation of resolution of claims and litigation where the Authority will be the defendant, plaintiff, petitioner, respondent, cross complainant or cross petitioner, or intervenor; provided, however, that the Chief Executive Officer or General Counsel, on behalf of the Authority, may intervene in, become party to, or file comments with respect to any proceeding pending at the California Public Utilities Commission, the Federal Energy Regulatory Commission, or any other administrative agency, without approval of the Board. The Board shall adopt Operating Rules and Regulations governing the Chief Executive Officer and General Counsel's exercise of authority under this Section 4.5.6.

4.5.7 The setting of rates for power sold by the Authority and the setting of charges for any other category of service provided by the Authority.

4.5.8 Termination of the CCA Program.

4.6 **Executive Committee**. The Board shall establish an Executive Committee consisting of a smaller number of Directors. The Board may delegate to the Executive Committee such authority as the Board might otherwise exercise, subject to limitations placed on the Board's authority to delegate certain Essential Functions, as described in Section 4.5 and the Operating Rules and Regulations. The Board may not delegate to the Executive Committee or any other committee its authority under Section 2.5.12 to adopt and amend the Operating Rules and Regulations or its Essential Functions listed in Section 4.5. After the Executive Committee meets or otherwise takes action, it shall, as soon as practicable, make a report of its activities at a meeting of the Board.

4.7 **Director Compensation**. Directors shall receive a stipend of $100 per meeting, as adjusted to account for inflation, as provided for in the Authority's Operating Rules and Regulations.

4.8 **Commissions, Boards and Committees**. The Board may establish any advisory commissions, boards and committees as the Board deems appropriate to assist the Board in carrying out its functions and implementing the CCA Program, other energy programs and the provisions of this Agreement. The Board may establish rules, regulations, policies, bylaws or procedures to govern any such commissions, boards, or committees and shall determine whether members shall be compensated or entitled to reimbursement for expenses.

4.9 **Community Advisory Committee**. The Board shall establish a Community Advisory Committee consisting of nine members, none of whom may be voting members of the Board. The function of the Community Advisory Committee shall be to advise the Board of Directors on all subjects related to the operation of the CCA Program as set forth in a work plan adopted by the Board of Directors from time to time, with the exception of personnel and litigation decisions. The Community Advisory Committee is advisory only, and shall not have decision-making authority, or receive any delegation of authority from the Board of Directors. The Board shall publicize the opportunity to serve on the Community Advisory Committee, and shall appoint members of the Community Advisory Committee from those individuals expressing interest in serving, and who represent a diverse cross-section of interests, skill sets and geographic regions. Members of the Community Advisory Committee shall serve staggered four-year terms (the first term of three of the members shall be two years, and four years thereafter), which may be renewed. A member of the Community Advisory Committee may be removed by the Board of Directors by majority vote. The Board of Directors shall determine whether the Community Advisory Committee members will receive a stipend and/or be entitled to reimbursement for expenses.

4.10 Chief Executive Officer. The Board of Directors shall appoint a Chief Executive Officer for the Authority, who shall be responsible for the day-to-day operation and management of the Authority and the CCA Program. The Chief Executive Officer may exercise all powers of the Authority, including the power to hire, discipline and terminate employees as well as the power to approve any agreement, if the expenditure is authorized in the Authority's approved budget, except the powers specifically set forth in Section 4.5 or those powers which by law must be exercised by the Board of Directors. The Board of Directors shall provide procedures and guidelines for the Chief Executive Officer exercising the powers of the Authority in the Operating Rules and Regulations.

4.11 General Counsel. The Board of Directors shall appoint a General Counsel for the Authority, who shall be responsible for providing legal advice to the Board of Directors and overseeing all legal work for the Authority.

4.12 Board Voting.

4.12.1 Percentage Vote. Except when a supermajority vote is expressly required by this Agreement or the Operating Rules and Regulations, action of the Board on all matters shall require an affirmative vote of a majority of all Directors on the entire Board (a "Percentage Vote" as defined in Section 1.1.20). A supermajority vote is required by this Agreement for the matters addressed by Section 8.4. When a supermajority vote is required by this Agreement or the Operating Rules and Regulations, action of the Board shall require an affirmative Percentage Vote of the specified supermajority of all Directors on the entire Board. No action can be taken by the Board without an affirmative Percentage Vote. Notwithstanding the foregoing, in the event of a tie in the Percentage Vote, an action may be approved by an affirmative "Voting Shares Vote," as defined in Section 1.1.22, if three or more Directors immediately request such vote.

4.12.2 Voting Shares Vote. In addition to and immediately after an affirmative percentage vote, three or more Directors may request that, a vote of the voting shares shall be held (a "Voting Shares Vote" as defined in Section 1.1.22). To approve an action by a Voting Shares Vote, the corresponding voting shares (as defined in Section 1.1.23 and Exhibit C) of all Directors voting in the affirmative shall exceed 50% of the voting share of all Directors on the entire Board, or such other higher voting shares percentage expressly required by this Agreement or the Operating Rules and Regulations. In the event that any one Director has a voting share that equals or exceeds that which is necessary to disapprove the matter being voted on by the Board, at least one other Director shall be required to vote in the negative in order to disapprove such matter. When a voting shares vote is held, action by the Board requires both an affirmative Percentage Vote and an affirmative Voting Shares Vote. Notwithstanding the foregoing, in the event of a tie in the Percentage Vote, an action may be approved on an affirmative Voting Shares Vote. When a supermajority vote is required by this Agreement or the Operating Rules and Regulations, the supermajority vote is subject to the Voting Share Vote provisions of this Section 4.12.2, and the specified supermajority of all Voting Shares is required for approval of the action, if the provision of this Section 4.12.2 are triggered.

4.13 **Meetings and Special Meetings of the Board**. The Board shall hold at least four regular meetings per year, but the Board may provide for the holding of regular meetings at more frequent intervals. The date, hour and place of each regular meeting shall be fixed by resolution or ordinance of the Board. Regular meetings may be adjourned to another meeting time. Special and Emergency meetings of the Board may be called in accordance with the provisions of California Government Code Section 54956 and 54956.5. Directors may participate in meetings telephonically, with full voting rights, only to the extent permitted by law.

4.14 **Officers**.

4.14.1 **Chair and Vice Chair**. At the first meeting held by the Board in each calendar year, the Directors shall elect, from among themselves, a Chair, who shall be the presiding officer of all Board meetings, and a Vice Chair, who shall serve in the absence of the Chair. The Chair and Vice Chair shall hold office for one year and serve no more than two consecutive terms, however, the total number of terms a Director may serve as Chair or Vice Chair is not limited. The office of either the Chair or Vice Chair shall be declared vacant and the Board shall make a new selection if: (a) the person serving dies, resigns, or ceases to be a member of the governing body of the Party that the person represents; (b) the Party that the person represents removes the person as its representative on the Board, or (c) the Party that he or she represents withdraws from the Authority pursuant to the provisions of this Agreement.

4.14.2 **Secretary**. The Board shall appoint a Secretary, who need not be a member of the Board, who shall be responsible for keeping the minutes of all meetings of the Board and all other official records of the Authority.

4.14.3 **Treasurer and Auditor**. The Board shall appoint a qualified person to act as the Treasurer and a qualified person to act as the Auditor, neither of whom needs to be a member of the Board. The same person may not simultaneously hold both the office of Treasurer and the office of the Auditor of the Authority. Unless otherwise exempted from such requirement, the Authority shall cause an independent audit to be made annually by a certified public accountant, or public accountant, in compliance with Section 6505 of the Act. The Treasurer shall act as the depositary of the Authority and have custody of all the money of the Authority, from whatever source, and as such, shall have all of the duties and responsibilities specified in Section 6505.5 of the Act. The Board may require the Treasurer and/or Auditor to file with the Authority an official bond in an amount to be fixed by the Board, and if so requested, the Authority shall pay the cost of premiums associated with the bond. The Treasurer shall report directly to the Board and shall comply with the requirements of treasurers of incorporated municipalities. The Board may transfer the responsibilities of Treasurer to any person or entity as the law may provide at the time.

4.15 **Administrative Services Provider**. The Board may appoint one or more administrative services providers to serve as the Authority's agent for planning, implementing, operating and administering the CCA Program, and any other program approved by the Board, in accordance with the provisions of an Administrative Services Agreement. The appointed administrative services provider may be one of the Parties. The Administrative Services Agreement shall set forth the terms and conditions by which the appointed administrative services provider shall perform or cause to be performed all tasks necessary for planning, implementing, operating and administering the CCA Program and other approved programs. The Administrative Services Agreement shall set forth the term of the Agreement and the circumstances under which the Administrative Services Agreement may be terminated by the Authority. This section shall not in any way be construed to limit the discretion of the Authority to hire its own employees to administer the CCA Program or any other program.

4.16 **Operational Audit**. The Authority shall commission an independent agent to conduct and deliver at a public meeting of the Board an evaluation of the performance of the CCA Program relative to goals for renewable energy and carbon reductions. The Authority shall approve a budget for such evaluation and shall hire a firm or individual that has no other direct or indirect business relationship with the Authority. The evaluation shall be conducted at least once every two years.

ARTICLE 5
IMPLEMENTATION ACTION AND AUTHORITY DOCUMENTS

5.1 Implementation of the CCA Program.

5.1.1 **Enabling Ordinance**. Prior to the execution of this Agreement, each Party shall adopt an ordinance in accordance with Public Utilities Code Section 366.2(c)(12) for the purpose of specifying that the Party intends to implement a CCA Program by and through its participation in the Authority.

5.1.2 Implementation Plan. The Authority shall cause to be prepared an Implementation Plan meeting the requirements of Public Utilities Code Section 366.2 and any applicable Public Utilities Commission regulations as soon after the Effective Date as reasonably practicable. The Implementation Plan shall not be filed with the Public Utilities Commission until it is approved by the Board in the manner provided by Section 4.12.

5.1.3 Termination of CCA Program. Nothing contained in this Article or this Agreement shall be construed to limit the discretion of the Authority to terminate the implementation or operation of the CCA Program at any time in accordance with any applicable requirements of state law.

5.2 **Other Authority Documents**. The Parties acknowledge and agree that the operations of the Authority will be implemented through various documents duly adopted by the Board through Board resolution or minute action, including but not necessarily limited to the Operating Rules and Regulations, the annual budget, and specified plans and policies defined as the Authority Documents by this Agreement. The Parties agree to abide by and comply with the terms and conditions of all such Authority Documents that may be adopted by the Board, subject to the Parties' right to withdraw from the Authority as described in Article 7.

5.3 **Integrated Resource Plan.** The Authority shall cause to be prepared an Integrated Resource Plan in accordance with CPUC regulations that will ensure the long-term development and administration of a variety of energy programs that promote local renewable resources, conservation, demand response, and energy efficiency, while maintaining compliance with the State Renewable Portfolio standard and customer rate competitiveness. The Authority shall prioritize the development of energy projects in Alameda and adjacent counties. Principal aspects of its planned operations shall be in a Business Plan as outlined in Section 5.4 of this Agreement.

5.4 **Business Plan.** The Authority shall cause to be prepared a Business Plan, which will include a roadmap for the development, procurement, and integration of local renewable energy resources as outlined in Section 5.3 of this Agreement. The Business Plan shall include a description of how the CCA Program will contribute to fostering local economic benefits, such as job creation and community energy programs. The Business Plan shall identify opportunities for local power development and how the CCA Program can achieve the goals outlined in Recitals 3 and 6 of this Agreement. The Business Plan shall include specific language detailing employment and labor standards that relate to the execution of the CCA Program as referenced in this Agreement. The Business Plan shall identify clear and transparent marketing practices to be followed by the CCA Program, including the identification of the sources of its electricity and explanation of the various types of electricity procured by the Authority. The Business Plan shall cover the first five (5) years of the operation of the CCA Program. The Business Plan shall be completed by the Authority no later than eight (8) months after the seating of the Authority Board of Directors. Progress on the implementation of the Business Plan shall be subject to annual public review.

5.5 Labor Organization Neutrality. The Authority shall remain neutral in the event its employees, and the employees of its subcontractors, if any, wish to unionize.

5.6 Renewable Portfolio Standards. The Authority shall provide its customers energy primarily from Category 1 eligible renewable resources, as defined under the California RPS and consistent with the goals of the CCA Program. The Authority shall not procure energy from Category 3 eligible renewable resources (unbundled Renewable Energy Credits or RECs) exceeding 50% of the State law requirements, to achieve its renewable portfolio goals. However, for Category 3 RECs associated with generation facilities located within its service jurisdiction, the limitation set forth in the preceding sentence shall not apply.

ARTICLE 6
FINANCIAL PROVISIONS

6.1 Fiscal Year. The Authority's fiscal year shall be 12 months commencing July 1 and ending June 30. The fiscal year may be changed by Board resolution.

6.2 Depository.

6.2.1 All funds of the Authority shall be held in separate accounts in the name of the Authority and not commingled with funds of any Party or any other person or entity.

6.2.2 All funds of the Authority shall be strictly and separately accounted for, and regular reports shall be rendered of all receipts and disbursements, at least quarterly during the fiscal year. The books and records of the Authority shall be open to inspection by the Parties at all reasonable times.

6.2.3 All expenditures shall be made in accordance with the approved budget and upon the approval of any officer so authorized by the Board in accordance with its Operating Rules and Regulations. The Treasurer shall draw checks or warrants or make payments by other means for claims or disbursements not within an applicable budget only upon the prior approval of the Board.

6.3 Budget and Recovery Costs.

6.3.1 Budget. The initial budget shall be approved by the Board. The Board may revise the budget from time to time through an Authority Document as may be reasonably necessary to address contingencies and unexpected expenses. All subsequent budgets of the Authority shall be prepared and approved by the Board in accordance with the Operating Rules and Regulations.

6.3.2 Funding of Initial Costs. The County shall fund the Initial Costs of establishing and implementing the CCA Program. In the event that the

CCA Program becomes operational, these Initial Costs paid by the County and any specified interest shall be included in the customer charges for electric services to the extent permitted by law, and the County shall be reimbursed from the payment of such charges by customers of the Authority. The Authority may establish a reasonable time period over which such costs are recovered. In the event that the CCA Program does not become operational, the County shall not be entitled to any reimbursement of the Initial Costs.

6.3.4 Additional Contributions and Advances. Pursuant to Government Code Section 6504, the Parties may in their sole discretion make financial contributions, loans or advances to the Authority for the purposes of the Authority set forth in this Agreement. The repayment of such contributions, loans or advances will be on the written terms agreed to by the Party making the contribution, loan or advance and the Authority.

ARTICLE 7
WITHDRAWAL AND TERMINATION

7.1 Withdrawal.

7.1.1 General Right to Withdraw. A Party may withdraw its membership in the Authority, effective as of the beginning of the Authority's fiscal year, by giving no less than 180 days advance written notice of its election to do so, which notice shall be given to the Authority and each Party. Withdrawal of a Party shall require an affirmative vote of the Party's governing board.

7.1.2 Withdrawal Following Amendment. Notwithstanding Section 7.1.1, a Party may withdraw its membership in the Authority following an amendment to this Agreement provided that the requirements of this Section 7.1.2 are strictly followed. A Party shall be deemed to have withdrawn its membership in the Authority effective 180 days after the Board approves an amendment to this Agreement if the Director representing such Party has provided notice to the other Directors immediately preceding the Board's vote of the Party's intention to withdraw its membership in the Authority should the amendment be approved by the Board.

7.1.3 The Right to Withdraw Prior to Program Launch. After receiving bids from power suppliers for the CCA Program, the Authority must provide to the Parties a report from the electrical utility consultant retained by the Authority comparing the Authority's total estimated electrical rates, the estimated greenhouse gas emissions rate and the amount of estimated renewable energy to be used with that of the incumbent utility. Within 30 days after receiving this report, through its City Manager or a person expressly authorized by the Party, any Party may immediately withdraw its membership in the Authority by providing written notice of withdrawal to the Authority if the report determines that any one of the following conditions exists: (1) the Authority is unable to provide total electrical rates, as part of its baseline offering to customers, that are equal to or lower than the incumbent utility, (2) the Authority is unable to provide electricity in a manner that has a lower greenhouse gas emissions rate than the incumbent utility, or (3) the Authority will use less qualified renewable energy than the incumbent utility. Any Party who withdraws from the Authority pursuant to this Section 7.1.3 shall not be entitled to any refund of the Initial Costs it has paid to the Authority prior to the date of withdrawal unless the Authority is later terminated pursuant to Section 7.3. In such event, any Initial Costs not expended by the Authority shall be returned to all Parties, including any Party that has withdrawn pursuant to this section, in proportion to the contribution that each made. Notwithstanding anything to the contrary in this Agreement, any Party who withdraws pursuant to this section shall not be responsible for any liabilities or obligations of the Authority after the date of withdrawal, including without limitation any liability arising from power purchase agreements entered into by the Authority.

7.2 **Continuing Liability After Withdrawal; Further Assurances; Refund.** A Party that withdraws its membership in the Authority under either Section 7.1.1 or 7.1.2 shall be responsible for paying its fair share of costs incurred by the Authority resulting from the Party's withdrawal, including costs from the resale of power contracts by the Authority to serve the Party's load and any similar costs directly attributable to the Party's withdrawal, such costs being limited to those contracts executed while the withdrawing Party was a member, and administrative costs associated thereto. The Parties agree that such costs shall not constitute a debt of the withdrawing Party, accruing interest, or having a maturity date. The Authority may withhold funds otherwise owing to the Party or may require the Party to deposit sufficient funds with the Authority, as reasonably determined by the Authority, to cover the Party's costs described above. Any amount of the Party's funds held by the Authority for the benefit of the Party that are not required to pay the Party's costs described above shall be returned to the Party. The withdrawing party and the Authority shall execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, as determined by the Board, to effectuate the orderly withdrawal of such Party from membership in the Authority. A withdrawing party has the right to continue to participate in Board discussions and decisions affecting customers of the CCA Program that reside or do business within the jurisdiction of the Party until the withdrawal's effective date.

7.3 **Mutual Termination.** This Agreement may be terminated by mutual agreement of all the Parties; provided, however, the foregoing shall not be construed as limiting the rights of a Party to withdraw its membership in the Authority, and thus terminate this Agreement with respect to such withdrawing Party, as described in Section 7.1.

7.4 **Disposition of Property upon Termination of Authority.** Upon termination of this Agreement as to all Parties, any surplus money or assets in possession of the Authority for use under this Agreement, after payment of all liabilities, costs, expenses, and charges incurred under this Agreement and under any Authority Documents, shall be returned to the then-existing Parties in proportion to the contributions made by each.

ARTICLE 8
MISCELLANEOUS PROVISIONS

8.1 Dispute Resolution. The Parties and the Authority shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. Before exercising any remedy provided by law, a Party or the Parties and the Authority shall engage in nonbinding mediation in the manner agreed upon by the Party or Parties and the Authority. The Parties agree that each Party may specifically enforce this section 8.1. In the event that nonbinding mediation is not initiated or does not result in the settlement of a dispute within 120 days after the demand for mediation is made, any Party and the Authority may pursue any remedies provided by law.

8.2 Liability of Directors, Officers, and Employees. The Directors, officers, and employees of the Authority shall use ordinary care and reasonable diligence in the exercise of their powers and in the performance of their duties pursuant to this Agreement. No current or former Director, officer, or employee will be responsible for any act or omission by another Director, officer, or employee. The Authority shall defend, indemnify and hold harmless the individual current and former Directors, officers, and employees for any acts or omissions in the scope of their employment or duties in the manner provided by Government Code Section 995 *et seq*. Nothing in this section shall be construed to limit the defenses available under the law, to the Parties, the Authority, or its Directors, officers, or employees.

8.3 Indemnification of Parties. The Authority shall acquire such insurance coverage as the Board deems necessary to protect the interests of the Authority, the Parties and the public. Such insurance coverage shall name the Parties and their respective Board or Council members, officers, agents and employees as additional insureds. The Authority shall defend, indemnify and hold harmless the Parties and each of their respective Board or Council members, officers, agents and employees, from any and all claims, losses, damages, costs, injuries and liabilities of every kind arising directly or indirectly from the conduct, activities, operations, acts, and omissions of the Authority under this Agreement.

8.4 Amendment of this Agreement. This Agreement may be amended in writing by a two-thirds affirmative vote of the entire Board satisfying the requirements described in Section 4.12. Except that, any amendment to the voting provisions in Section 4.12 may only be made by a three-quarters affirmative vote of the entire Board. The Authority shall provide written notice to the Parties at least 30 days in advance of any proposed amendment being considered by the Board. If the proposed amendment is adopted by the Board, the Authority shall provide prompt written notice to all Parties of the effective date of such amendment along with a copy of the amendment.

8.5 **Assignment**. Except as otherwise expressly provided in this Agreement, the rights and duties of the Parties may not be assigned or delegated without the advance written consent of all of the other Parties, and any attempt to assign or delegate such rights or duties in contravention of this Section 8.5 shall be null and void. This Agreement shall inure to the benefit of, and be binding upon, the successors and assigns of the Parties. This Section 8.5 does not prohibit a Party from entering into an independent agreement with another agency, person, or entity regarding the financing of that Party's contributions to the Authority, or the disposition of proceeds which that Party receives under this Agreement, so long as such independent agreement does not affect, or purport to affect, the rights and duties of the Authority or the Parties under this Agreement.

8.6 **Severability**. If one or more clauses, sentences, paragraphs or provisions of this Agreement shall be held to be unlawful, invalid or unenforceable, it is hereby agreed by the Parties, that the remainder of the Agreement shall not be affected thereby. Such clauses, sentences, paragraphs or provision shall be deemed reformed so as to be lawful, valid and enforced to the maximum extent possible.

8.7 **Further Assurances**. Each Party agrees to execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, to effectuate the purposes and intent of this Agreement.

8.8 **Execution by Counterparts**. This Agreement may be executed in any number of counterparts, and upon execution by all Parties, each executed counterpart shall have the same force and effect as an original instrument and as if all Parties had signed the same instrument. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signature pages.

8.9 **Parties to be Served Notice**. Any notice authorized or required to be given pursuant to this Agreement shall be validly given if served in writing either personally, by deposit in the United States mail, first class postage prepaid with return receipt requested, or by a recognized courier service. Notices given (a) personally or by courier service shall be conclusively deemed received at the time of delivery and receipt and (b) by mail shall be conclusively deemed given 72 hours after the deposit thereof (excluding Saturdays, Sundays and holidays) if the sender receives the return receipt. All notices shall be addressed to the office of the clerk or secretary of the Authority or Party, as the case may be, or such other person designated in writing by the Authority or Party. In addition, a duplicate copy of all notices provided pursuant to this section shall be provided to the Director and alternate Director for each Party. Notices given to one Party shall be copied to all other Parties. Notices given to the Authority shall be copied to all Parties. All notices required hereunder shall be delivered to:

The County of Alameda

Director, Community Development Agency

224 West Winton Ave.
Hayward, CA 94612

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

if to [PARTY No. ____]

Office of the City Clerk

____

____

Office of the City Manager/Administrator

____

____

Office of the City Attorney

____

____

if to [PARTY No._____]

Office of the City Clerk

____

____

Office of the City Manager/Administrator

____

____

Office of the City Attorney

____

____

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: ______________________________

Name: ____________________________

Title: _____________________________

Date: _____________________________

Party: ____________________________

EXHIBIT A

-LIST OF THE PARTIES

(This draft exhibit is based on the assumption that all of the Initial Participants will become Parties. On the Effective Date, this exhibit will be revised to reflect the Parties to this Agreement at that time.)-

-

DRAFT EXHIBIT B

-ANNUAL ENERGY USE

(This draft exhibit is based on the assumption that <u>all</u> of the Initial Participants will become Parties. On the Effective Date, this exhibit will be revised to reflect the Parties to this Agreement at that time.)

This Exhibit B is effective as of ________________.

Party	**kWh ([YEAR]*)**

*Data provided by PG&E

DRAFT EXHIBIT C

- VOTING SHARES

(This draft exhibit is based on the assumption that all of the Initial Participants will become Parties. On the Effective Date, this exhibit will be revised to reflect the Parties to this Agreement at that time.)

This Exhibit C is effective as of ___________________.

Party	kWh ([YEAR]*)	Voting Share Section 4.11.2
Total		

*Data provided by PG&E

Attachment F

CITY OF
HAYWARD
HEART OF THE BAY

September 27, 2016

Bruce Jensen, Senior Planner
Alameda County Community Development Agency
224 West Winton Avenue, Room 111
Hayward, CA 94544

Sent via email to: bruce.jensen@acgov.org

Dear Mr. Jensen:

Subject: Draft JPA Agreement for East Bay Community Energy

I appreciate the efforts made by Alameda County to establish East Bay Community Energy (EBCE). I understand the County is challenged by trying to address many competing concerns and to develop a joint powers agreement that will be acceptable to all parties involved. I also understand the need to keep the process moving forward and to obtain timely approval from the Board of Supervisors so that EBCE can be launched on schedule.

I have reviewed the latest draft of the JPA dated September 13, 2016 and noticed that Sections 1.1.22 and 4.12 still show that "three" directors are required to request a voting shares vote.

In order to increase the likelihood that our full city council will vote to join the JPA, I urge County staff and the Board of Supervisors to revise Sections 1.1.22 and 4.12 to change the threshold for requesting a voting shares vote from "three" back to "two" as it was in earlier drafts. It is logical that the threshold to request a voting shares vote is lower than the minimum number of cities needed to carry a voting shares vote.

Thank you, in advance, for your consideration.

Sincerely,

Al Mendall

Al Mendall
City Council Member and Steering Committee Representative

CC:

Elisa Marquez, Hayward City Council Member and Steering Committee Alternate
Kelly McAdoo, Hayward City Manager

OFFICE OF THE MAYOR AND CITY COUNCIL

777 B STREET, HAYWARD, CA 94541-5007
TEL: 510/583-4340 • FAX: 510/583-3601 • TDD: 510/247-3340

CITY OF BERKELEY

Office of the Mayor

September 28, 2016

Bruce Jensen, Senior Planner
Alameda County Community Development Agency
224 West Winton Avenue, Room 111
Hayward, CA 94544

Sent via email to: bruce.jensen@acgov.org

Dear Mr. Jensen:

Subject: Draft JPA Agreement for East Bay Community Energy

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Thank you, in advance, for your consideration.

Sincerely,

Tom Bates

Tom Bates
Mayor
CC:

Dee Williams-Ridley, City Manager, City of Berkeley
Timothy Burroughs, Assistant to the City Manager, City of Berkeley
Zach Cowan, City Attorney, City of Berkeley

CITY OF Fremont
Office of the Mayor
3300 Capitol Avenue, Building A | P.O. Box 5006, Fremont, CA 94537-5006
510 284-4011 *ph* | 510 284-4001 *fax* | www.fremont.gov

September 28, 2016

Bruce Jensen, Senior Planner
Alameda County Community Development Agency
224 West Winton Avenue, Room 111
Hayward, CA 94544

Via Email: bruce.jensen@acgov.org

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Thank you, in advance, for your consideration.

Sincerely,

Bill Harrison

Bill Harrison
Mayor

cc: Fred Diaz, City Manager
Dan Schoenholz (Steering Committee Representative)
Rachel DiFranco (Steering Committee Alternate)

Dan Kalb
Oakland City Councilmember

One Frank Ogawa Plaza, 2nd floor • Oakland, CA 94612 • 510-238-7001

September 29, 2016

Bruce Jensen, Senior Planner (via e-mail to bruce.jensen@acgov.org)
Alameda County Community Development Agency
224 West Winton Ave., Room 111
Hayward, CA 94544

RE: Draft JPA Agreement for East Bay Community Energy

Dear Mr. Jensen,

I appreciate tremendously the efforts made by Alameda County to establish an East Bay Community Energy (EBCE) authority. I personally support this effort and hope we can get to a point where all or nearly all the cities in the County decide to participate.

Leading up to and during the most recent Advisory Committee meeting, it has been clear that County staff has been attempting to work through the various JPA elements and the interests shared by stakeholders. I realize that it is quite difficult to craft a proposed JPA agreement that meets everyone's needs and desires. I also fully understand the need to keep the process moving forward and to obtain timely approval from the Board of Supervisors so that EBCE can be launched within a reasonable timeframe.

I have reviewed multiple drafts of the proposed JPA agreement and participated in the advisory committee discussions. I also have had multiple discussions about the content of the document with our city attorney and assistant city administrator. I must take this opportunity—before the Supervisors cast their vote—to share with you that, as the representative of the City of Oakland, **I continue to oppose requiring any more than two Authority Board members be able to call for a so-called 'voting shares' vote.**

In order to reduce the possibility of significant bumps in the road regarding potential approval by our City Council, I urge County staff and the Board of Supervisors to revise the appropriate sections in the JPA agreement to change the threshold for requesting a 'voting shares' vote from 'three' back to 'two' as it was in earlier drafts throughout the year. The proposed JPA agreement does not prioritize proportional representation based on population, nor does it give the one or two largest cities an extra vote during the percentage vote, as is the case with other JPAs in Alameda County. Ensuring that some modicum of proportionality exists in the democratic voting structure is important. Therefore, requiring no more than two members of the JPA body to call for a voting shares vote makes sense and is consistent with Robert's Rules of Order. After all, merely calling for a vote requires nothing more than a motion and a second.

Thank you for your thoughtful consideration.

Truly,

Dan Kalb
Oakland City Councilmember and Steering Committee representative

CC: Christine Daniel, Chris Bazar, Shawn Wilson, Brian Washington, Daniel Hamilton

Attachment G

PORT OF OAKLAND

October 18, 2016

Susan Kattchee
Assistant Director
Department of Facilities & Environment
250 Frank H. Ogawa Plaza, Suite 5301
Oakland, CA 94612

Dear Ms. Kattchee:

Thank you for our conference call last week discussing the Alameda County-wide effort and the City's role in establishing a Community Choice Aggregation ("CCA") program. This letter responds to your request for a letter from the Port stating what the Port is asking the City to do.

Let me first state that the Port recognizes and supports the City's and the County's efforts to not only increase the use of renewable energy but to also make such renewable energy available for the members of the communities participating in that effort. The Port of Oakland has been monitoring the CCA effort over the past few years and is pleased the effort appears to be reaching a point where the CCA launch looks imminent.

As you know, the Port of Oakland operates its own municipal electric utility, and is the sole provider of electricity at the Airport and the largest service provider of electricity in the Seaport area. In partnership with the Northern California Power Authority ("NCPA"), a JPA of publicly owned utilities throughout Northern California, the Port procures power on behalf of its tenants. The Port's electric utility system provides significant benefit to our tenants in the form of energy efficiency programs, rooftop solar rebates, and competitive electric rates for electric service that is 50-80% GHG-free depending on how much hydroelectric energy the Port receives in any given year. The Board of Port Commissioners ("Port Commission") has approved a renewable energy procurement program, and the Port is taking steps to meet the state requirements of 50% renewables by 2030 and recently executed a renewable energy contract extension with EBMUD for clean, local renewable power. The Port's municipal electric utility operations and goals to provide cost-efficient and clean power are consistent and complementary to the goals of the CCA

Given the value the Port utility provides to its customers in the form of low-cost, clean energy, it would be duplicative to overlay the CCA over areas where the Port has its own electrical utility infrastructure. Furthermore, the Port, unlike other municipal members of the CCA, has a unique mission to tailor its utility services to the needs of aviation and maritime tenants of the Port. The Port Commission, vested with the exclusive and complete management of Port operations and having the duty to provide for the needs of commerce, shipping and navigation within the Port Area pursuant to Section 706(2) of the City Charter, is the legally appropriate legislative body to decide the scope and extent of the Port's participation in the CCA.

530 Water Street ■ Jack London Square ■ P.O. Box 2064 ■ Oakland, California 94604-2064
Telephone: (510) 627-1100 ■ Facsimile: (510) 627-1826 ■ Web Page: www.portofoakland.com

After our conference call, the Port has had some further discussion on this matter, and I wish to advise you that Port staff intends to recommend to the Board of Port Commissioners that it adopt its own ordinance requesting that all areas of the Port Area (as defined in Section 725 of the City Charter) become a part of the Alameda County CCA ***except*** for those areas within the Port Area that are or will be served by the Port's own electric distribution system. In this way, the Port will both participate in the CCA in areas where the Port utility does not have the capacity to supply power and preserve the cost-efficient and clean energy service where the Port currently has such capacity. Therefore, the Port requests that the City Council's ordinance exempts the Port Area in order to allow the Port Commission to join the CCA in a manner that would not duplicate or conflict with the operations and goals of the Port's electric utility.

We appreciate the time and effort your staff have taken to assist us through this process, and we would be happy to continue working with you as we each prepare our respective ordinances. If you have any questions regarding this matter, please feel free to contact me directly at (510) 627-1167.

Sincerely,

N. Procos

Nicolas Procos
Manager of Utilities Administration

cc: Becky Dowdakin, Environmental Services Manager, City of Oakland
Dan Hamilton, Manager Sustainability Program, City of Oakland
Celso Ortiz, Deputy City Attorney, City of Oakland
Chris Lytle, Executive Director, Port of Oakland
Chris Chan, Director of Engineering, Port of Oakland
Danny Wan, Port Attorney, Port of Oakland
Donnell Choy, Deputy Port Attorney, Port of Oakland

INTRODUCED BY COUNCILMEMBER KALB AND MAYOR SCHAAF

City Attorney

City Attorney

OAKLAND CITY COUNCIL

ORDINANCE NO.____________C.M.S.

ORDINANCE AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE ENERGY PROGRAM WITHIN THE CORPORATE BOUNDARIES OF THE CITY OF OAKLAND TO BECOME EFFECTIVE THIRTY DAYS FOLLOWING THE FINAL PASSAGE OF THE ORDINANCE

WHEREAS, the County of Alameda ("County") and cities within it have been actively investigating options to provide electricity supply services to constituents within the County with the intent of achieving greater local involvement over the provision of electricity supply services, competitive electric rates, the development of local renewable energy projects, reduced greenhouse gas emissions, and the wider implementation of energy conservation and efficiency projects and programs; and

WHEREAS, Assembly Bill 117, codified as Public Utilities Code Section 366.2 (the "Act"), authorizes any California city or county whose governing body so elects, to combine the electricity load of its residents and businesses in a community wide electricity energy program known as Community Choice Energy ("CCE"); and

WHEREAS, The Act allows a CCE program to be carried out under a joint powers agreement entered into by entities that each have capacity to implement a CCE program individually. The joint power agreement structure reduces the risks of implementing a CCE program by immunizing the financial assets of participants. To this end, since 2014, the County has been evaluating a potential CCE program for the County and the cities within Alameda County; and

WHEREAS, The County Board of Supervisors voted unanimously in June of 2014 to allocate funding to explore the creation of a CCE Program and directed County staff to undertake the steps necessary to evaluate its feasibility. To assist in the evaluation of the CCE program within Alameda County, the County established a Steering Committee, in 2015, that has met monthly, advising the Board of Supervisors on the possibility of creating a CCE Program; and

WHEREAS, The Technical Feasibility Study completed in June of 2016 shows that implementing a Community Choice Energy program would likely provide multiple benefits to the citizens of Alameda County, including the following: 1. Providing customers a choice of power providers; 2. Increasing local control over energy rates and other energy-related matters; 3. Providing electric rates that are competitive with those provided by the incumbent utility; 4. Reducing greenhouse gas emissions arising from electricity use; 5. Increasing local and regional renewable generation capacity; Page 164 of 190 388 6. Increasing energy conservation and efficiency projects and programs; 7. Increasing regional energy self-sufficiency; and 8. Encouraging local economic and employment benefits through energy conservation and efficiency projects; and

WHEREAS, Representatives from the County and Alameda County cities have developed the East Bay Community Energy Authority Joint Powers Agreement ("Joint Powers Agreement") (attached hereto as Exhibit A). The Joint Powers Agreement creates the East Bay Community Energy Authority ("Authority"), which will govern and operate the CCE program. The County and the Alameda County cities that elect to participate in the CCE Program shall do so by approving the execution of the Joint Powers Agreement and adopting an ordinance electing to implement a CCE Program, as required by Public Utilities Code Section 366.2(c)(12); and

WHEREAS, The Authority will enter into agreements with electric power suppliers and other service providers and, based upon those agreements, the Authority plans to provide electrical power to residents and businesses at rates that are competitive with those of the incumbent utility. Upon the California Public Utilities Commission approving the implementation plan prepared by the Authority, the Authority can provide service to customers within it member jurisdictions. Under Public Utilities Code Section 366.2, customers have the right to opt-out of a CCE program and continue to receive service from the incumbent utility. Customers who wish to continue to receive service from the incumbent utility will be able to do so at any time;

NOW, THEREFORE, THE COUNCIL OF THE CITY OF OAKLAND DOES ORDAIN AS FOLLOWS:

Section 1. Based upon all of the above, City Council elects to implement a Community Choice Energy program within the City's jurisdiction by and through the City's participation in the East Bay Community Energy Authority.

IN COUNCIL, OAKLAND, CALIFORNIA, ______________________________

PASSED BY THE FOLLOWING VOTE:

AYES-

NOES-

ABSENT-

ABSTENTION-

ATTEST: ____________________________

LaTonda Simmons
City Clerk and Clerk of the Council
of the City of Oakland, California

DATE OF ATTESTATION: ________________________

OAKLAND CITY COUNCIL

City Attorney

RESOLUTION NO.____________C.M.S.

Introduced by Councilmember Kalb and Mayor Schaaf

RESOLUTION APPROVING THE EAST BAY COMMUNITY ENERGY AUTHORITY JOINT POWERS AGREEMENT AND AUTHORIZE THE CITY ADMINISTRATOR TO EXECUTE THE EAST BAY COMMUNITY ENERGY AUTHORITY JOINT POWERS AGREEMENT; AND ADOPTING CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA) EXEMPTION FINDINGS

WHEREAS, AB 117, adopted as California state law in 2002, permits cities, counties, or city and county Joint Power Authorities to aggregate residential, commercial, industrial, municipal and institutional electric loads through Community Choice Aggregation (CCA); and

WHEREAS, the Oakland City Council is on record in support of this legislation; and

WHEREAS, there are numerous potential benefits for cities and counties that aggregate including: 1) More stable and reliable power supplies; 2) An expectation of lower electricity rates for residents, businesses and municipal operations compared to the rates of Pacific Gas & Electric Company (PG&E); 3) Opportunity for general fund revenue; 4) Greater use of renewable energy resources than are planned by PG&E; 5) Ratepayer access to a democratically elected governing body (the Oakland City Council); and,

WHEREAS, on May 12, 2005, City Council adopted Resolution No. 79325 C.M.S., declaring the City's intent to become a CCA and procure electricity on behalf of Oakland's electric customers; and

WHEREAS, in December 2012, the City Council approved Resolution No. 84126 C.M.S., adopting the City's Energy and Climate Action Plan (ECAP), which provides the actions and programs needed for the City to reach the goal of reducing greenhouse gas (GHG) emissions 36 percent by 2020; and

WHEREAS, ECAP Priority Action 52 states that the City will "continue to monitor the feasibility and utility of implementing community choice energy aggregation in Oakland," and will revisit the program design and needed resources if CCA is demonstrated as a successful model; and

WHEREAS, four CCA programs are currently providing electricity in California, including Marin Clean Energy, CleanPowerSF, Sonoma Clean Power, and Lancaster Choice Energy; and

WHEREAS, in June 2014, the Alameda County Board of Supervisors passed a resolution to explore the creation of a CCA program countywide, to include all eligible cities; and

WHEREAS, in February 2015, the Board of Supervisors passed a subsequent resolution forming a CCA Steering Committee representing cities, key stakeholders, and energy experts ; and

WHEREAS, in March 2015, the County officially invited the City of Oakland to serve on the Steering Committee; and

WHEREAS, in June 2015, City Council passed Resolution No. 85660 C.M.S. supporting the creation of a countywide CCA, appointing a representative and alternate representative to the CCA Steering Committee, and establishing goals for the proposed CCA program, which include providing electricity at lower rates than PG&E, prioritizing development of local renewable energy, reducing greenhouse gases, and creating clean energy jobs in the community; and

WHEREAS, in May 2016, City Council received a presentation on the CCA program from the Alameda County Planning Director; and

WHEREAS, in July 2016, City Council received an informational report on Draft Joint Powers Authority Agreement for Proposed East Bay Community Choice Energy JPA; and

WHEREAS, Alameda County conducted a feasibility study that concluded an Alameda CCA program is feasible, should be able to offer residents and businesses electric rates that are a cent or more per kilowatt-hour lower cost than that available from PG&E under most scenarios, could help facilitate greater amounts of renewable electricity generation to be developed in Alameda County, could reduce greenhouse gas emissions relative to PG&E, but only under certain circumstances, and can offer positive economic development and employment benefits both in the area and beyond; and

WHEREAS, the high desire and demand for clean, renewable energy is creating opportunities for work in the development of new renewable power generation through the building of local and in-state renewable energy in which the Oakland City Council and organized labor are united in ensuring that local union jobs are prioritized in the implementation of the clean energy economy; and

WHEREAS, a Community Choice energy program can accelerate the transition to renewable energy resources and reduce greenhouse gas emissions in the electricity sector, helping to achieve the goals of Oakland's Energy and Climate Action Plan (ECAP); and

WHEREAS, a Community Choice energy program that prioritizes the development of local renewable resources will likely create wealth within the community, boost Oakland's economy, and foster local business development; and

WHEREAS, a Community Choice energy program that prioritizes the development of local renewable resources can create family-sustaining clean energy jobs prioritizing training through union-sponsored apprenticeship programs, hiring of local residents, and expanding the number of unionized and similarly paid and benefitted jobs in the electricity sector thereby helping to lower Oakland's unemployment rate, provide for stable and reasonable wages and working conditions and electricity rates, including rates competitive with PG&E, and incentivize energy efficiency at the local level; and

WHEREAS, a Community Choice energy program can democratize energy by giving the community control and effective ownership of the energy supply and providing residents and businesses with access to a local, public energy agency; and

WHEREAS, a Community Choice energy program can target different categories of electricity customers to incentivize demand reduction and renewable energy installations and include programs to promote ownership of renewable energy assets for low and moderate income residents and communities of color, as well as those who do not own buildings and are often shut out of participation in the clean energy economy; now, therefore, be it

RESOLVED: That the City Council hereby authorizes the City Administrator to enter into an agreement with the East Bay Community Energy Authority Joint Powers Authority (EBCEA) to purchase energy, including clean energy, at lower costs than would be available through direct contracts with PG&E; and be it

FURTHER RESOLVED: That the City Council hereby adopts the California Environmental Quality Act findings set forth in the Agenda Report.

IN COUNCIL, OAKLAND, CALIFORNIA, ______________________________

PASSED BY THE FOLLOWING VOTE:

AYES -

NOES -

ABSENT -

ABSTENTION -

ATTEST:______________________________

LaTonda Simmons
City Clerk and Clerk of the Council
of the City of Oakland, California