Western Riverside Council of Governments
Executive Committee

AGENDA

Monday, February 6, 2017
2:00 p.m.

County of Riverside
Administrative Center
4080 Lemon Street
1st Floor, Board Chambers
Riverside, CA 92501

The following teleconference number is provided exclusively for members of the public wishing to address the Executive Committee directly during the public hearing portion of item 6.A on the agenda:

Teleconference: (877) 336-1828
Access Code: 5233066

In compliance with the Americans with Disabilities Act and Government Code Section 54954.2, if special assistance is needed to participate in the Executive Committee meeting, please contact WRCOG at (951) 955-8320. Notification of at least 48 hours prior to meeting time will assist staff in assuring that reasonable arrangements can be made to provide accessibility at the meeting. In compliance with Government Code Section 54957.5, agenda materials distributed within 72 hours prior to the meeting which are public records relating to an open session agenda item will be available for inspection by members of the public prior to the meeting at 4080 Lemon Street, 3rd Floor, Riverside, CA, 92501.

The Executive Committee may take any action on any item listed on the agenda, regardless of the Requested Action.

1. CALL TO ORDER / ROLL CALL (Ben Benoit, Chair)

2. PLEDGE OF ALLEGIANCE

3. PUBLIC COMMENTS

At this time members of the public can address the Executive Committee regarding any items within the subject matter jurisdiction of the Executive Committee that are not separately listed on this agenda. Members of the public will have an opportunity to speak on agendized items at the time the item is called for discussion. No action may be taken on items not listed on the agenda unless authorized by law. Whenever possible, lengthy testimony should be presented to the Executive Committee in writing and only pertinent points presented orally.

4. CONSENT CALENDAR

All items listed under the Consent Calendar are considered to be routine and may be enacted by one motion. Prior to the motion to consider any action by the Executive Committee, any public comments on any of the Consent Items will be heard. There will be no separate action unless members of the Executive Committee request specific items be removed from the Consent Calendar.

Action items:

A. Summary Minutes from the January 9, 2017, Executive Committee meeting are available for consideration. **P. 1**

Requested Action: *1. Approve Summary Minutes from the January 9, 2017, Executive Committee meeting.*

B. 2nd Quarter Draft Budget Amendment for Fiscal Year 2016/2017 ***Ernie Reyna*** **P. 15**

Requested Action: *1. Approve the 2nd Quarter Draft Budget Amendment for Fiscal Year 2016/2017.*

C. Flabob Airport TUMF Appeal ***Christopher Gray*** **P. 35**

Requested Action: *1. Approve the appeal consistent with the recommendation from staff and the Administration & Finance Committee.*

D. RIVCOconnect Broadband Initiative ***David Littell, County of Riverside IT*** **P. 51**

Requested Action: *1. Adopt WRCOG Resolution Number 02-17; A Resolution of the Executive Committee of the Western Riverside Council of Governments to Support Riverside County Information Technology's Broadband Initiative – RIVCOconnect.*

Information items:

E. Finance Department Activities Update ***Ernie Reyna*** **P. 61**

Requested Action: *1. Receive and file.*

F. Financial Report Summary through November 2016 ***Ernie Reyna*** **P. 63**

Requested Action: *1. Receive and file.*

G. Regional Streetlight Program Activities Update ***Tyler Masters*** **P. 69**

Requested Action: *1. Receive and file.*

H. Western Riverside Energy Leader Partnership Update ***Tyler Masters*** **P. 73**

Requested Action: *1. Receive and file.*

I. Environmental Department Activities Update ***Dolores Sanchez Badillo*** **P. 75**

Requested Action: *1. Receive and file.*

J. Clean Cities Coalition Activities Update ***Christopher Gray*** **P. 79**

Requested Action: *1. Receive and file.*

K. Single Signature Authority Report — *Ernie Reyna* — **P. 87**

Requested Action: *1. Receive and file.*

L. Public Service Fellowship Program — *Jennifer Ward* — **P. 93**

Requested Action: *1. Receive and file.*

M. Report from the League of California Cities — *Erin Sasse, League of California Cities* — **P. 95**

Requested Action: *1. Receive and file.*

5. ITEMS PULLED FOR DISCUSSION

6. REPORTS / DISCUSSION

Action Items:

A. PACE Program Activities Update — *Barbara Spoonhour, WRCOG* — **P. 107**

Requested Action: *1. Support the WRCOG PACE Ad Hoc Committee's recommendation for the HERO Program to implement some new rate options, and direct staff to return in 90-days with a report on Program revisions and impacts.*

B. Community Choice Aggregation Program Activities Update — *Barbara Spoonhour, WRCOG* — **P. 121**

Requested Action:
1. Receive the final draft Inland Choice Power Community Choice Aggregation Business Plan.
2. Direct the Executive Director to prepare and issue a Request for Proposals for CCA contract services.

C. Potential WRCOG Agency Office Relocation — *Rick Bishop, WRCOG* — **P. 239**

Requested Action: *1. Approve staff's recommendation to relocate the WRCOG offices to the Pacific Premiere Bank building and seek a 10-year lease agreement with the County of Riverside.*

Information Items:

D. Transportation Uniform Mitigation Fee (TUMF) Program Activities Update — *Christopher Gray, WRCOG* — **P. 241**

Requested Action: *1. Receive and file.*

7. REPORT FROM THE TECHNICAL ADVISORY COMMITTEE CHAIR — *Gary Nordquist*

8. REPORT FROM COMMITTEE REPRESENTATIVES

SCAG Regional Council and Policy Committee representatives

SCAQMD, Ben Benoit
CALCOG, Brian Tisdale

9. REPORT FROM THE EXECUTIVE DIRECTOR ***Rick Bishop***

10. ITEMS FOR FUTURE AGENDAS ***Members***

Members are invited to suggest additional items to be brought forward for discussion at future Executive Committee meetings.

11. GENERAL ANNOUNCEMENTS ***Members***

Members are invited to announce items / activities which may be of general interest to the Executive Committee.

12. CLOSED SESSION

CONFERENCE WITH LEGAL COUNSEL – EXISTING LITIGATION PURSUANT TO SECTION 54956.9(d)(1):

- **Case Number 30-2010-00357976**

13. NEXT MEETING: **The next Executive Committee meeting is scheduled for Monday, March 6, 2017, at 2:00 p.m., at the County of Riverside Administrative Center, 1st Floor Board Chambers.**

14. ADJOURNMENT

Western Riverside Council of Governments

Regular Meeting
~ Minutes ~

Monday, January 9, 2017 | **2:00 PM** | **County Administrative Center**

1. CALL TO ORDER / ROLL CALL

The meeting called to order at 2:05 p.m. on January 9, 2017, at County Administrative Center, 4080 Lemon Street, Riverside, CA.

Jurisdiction	Attendee Name	Status	Arrived
City of Banning	Debbie Franklin	Present	1:59 PM
City of Calimesa		Absent	
City of Canyon Lake	Jordan Ehrenkranz	Present	1:56 PM
City of Corona	Eugene Montanez	Present	1:51 PM
City of Eastvale	Adam Rush	Present	1:57 PM
City of Hemet	Bonnie Wright	Present	2:05 PM
City of Jurupa Valley	Laura Roughton	Present	1:56 PM
City of Lake Elsinore	Brian Tisdale	Present	2:01 PM
City of Menifee	John Denver	Present	1:55 PM
City of Moreno Valley	Yxstian Gutierrez	Present	2:02 PM
City of Murrieta	Kelly Seyarto	Present	1:51 PM
City of Norco	Kevin Bash	Present	2:01 PM
City of Perris	Rita Rogers	Present	1:57 PM
City of Riverside	Rusty Bailey	Present	2:04 PM
City of San Jacinto	Crystal Ruiz	Present	1:58 PM
City of Temecula	Mike Naggar	Present	1:57 PM
City of Wildomar		Absent	
District 1	Kevin Jeffries	Present	1:59 PM
District 2		Absent	
District 3	Chuck Washington	Present	2:00 PM
District 5	Marion Ashley	Present	2:04 PM
EMWD	David Slawson	Present	1:56 PM
WMWD	Brenda Dennstedt	Present	1:52 PM
Morongo		Absent	
Office of Education		Absent	
TAC Chair	Gary Nordquist	Present	1:56 PM
Executive Director	Rick Bishop	Present	1:58 PM

Note: Times above reflect when the member logged in; they may have arrived at the meeting earlier.

2. PLEDGE OF ALLEGIANCE

Committee member Bonnie Wright led members and guests in the Pledge of Allegiance.

3. WELCOME NEW MEMBERS

Chairman Franklin welcomed Mayor Yxstian Gutierrez, City of Moreno Valley; Councilmember Kelly Seyarto, City of Murrieta; and Councilmember Adam Rush, City of Eastvale.

4. PUBLIC COMMENTS

Arnold San Miguel of SCAG announced that an earthquake readiness workshop is scheduled for January 31, 2017, in Ontario. Goals include development of framework to address local vulnerabilities; provide toolkits to support efforts in achieving results for taking action in a reasonable timeframe; and share strategies to build, establish, and/or enhance community-wide partnerships. Each city is being asked to send three representatives.

SCAG is also seeking nominations for its Sustainability Awards; the deadline is in January 2017.

Chairwoman Franklin presented a Proclamation to outgoing Executive Committee member Councilmember Randon Lane, City of Murrieta.

Councilmember Lane stated that he has enjoyed his time on this Committee as both a member and as a past Chairman. Councilmember Lane thanked staff and Committee members for all their hard work.

5. CONSENT CALENDAR

RESULT:	**APPROVED AS RECOMMENDED [UNANIMOUS]**
MOVER:	City of San Jacinto
SECONDER:	City of Corona
AYES:	Banning, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley, Lake Elsinore, Menifee, Moreno Valley, Murrieta, Norco, Perris, Riverside, San Jacinto, Temecula, District 1, District 3, District 5, EMWD, WMWD
ABSENT:	City of Calimesa, City of Wildomar, District 2, Morongo

A. Summary Minutes from the December 5, 2016, Executive Committee meeting are available for consideration.

Action: *Approved Summary Minutes from the December 5, 2016, Executive Committee meeting.*

B. Finance Department Activities Update

Action: *Received and filed.*

C. Financial Report Summary through October 2016

Action: *Received and filed.*

D. Community Choice Aggregation Program Activities Update

Action: *Received and filed.*

E. Regional Streetlight Program Contract Extension

Action: *Received and filed.*

F. Western Riverside Energy Leader Partnership Update

Action: *Received and filed.*

G. Environmental Department Activities Update

Action: *Received and filed.*

H. Clean Cities Coalition Activities Update

Action: *Received and filed.*

I. Analysis of Fees and Their Potential Impact on Economic Development in Western Riverside County

Action: *Received and filed.*

J. PACE Debt Management Policy

Action: *Approved the Debt Management Policy.*

6. ITEMS PULLED FOR DISCUSSION

There were no items pulled for discussion.

7. REPORTS / DISCUSSION

A. PACE Program Activities Update

Michael Wasgatt reported that there are currently 361 jurisdictions participating in the California HERO Program; 161,000 applications have been submitted, of which 105,350 have been approved, for over $6.4 billion in funding. In the WRCOG HERO Program, over 52,000 applications have been submitted, of which 35,000 have been approved, for over $427 million in funding.

Overall, 39,000 energy and water efficiency measures have been installed in Western Riverside County, which equates to nearly $740 million in economic impact; 3,622 jobs created, 1.34 billion gallons of water saved, 847,000 tons of greenhouse gas emissions reduced, and 314 gigawatt hours of energy saved.

Chairwoman Franklin opened the public hearing; there were no comments and the public hearing was closed.

RESULT:	**APPROVED AS RECOMMENDED [UNANIMOUS]**
MOVER:	City of Temecula
SECONDER:	District 5
AYES:	Banning, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley, Lake Elsinore, Menifee, Moreno Valley, Murrieta, Norco, Perris, Riverside, San Jacinto, Temecula, District 1, District 3, District 5, EMWD, WMWD
ABSENT:	City of Calimesa, City of Wildomar, District 2, Morongo

Actions:

1. *Received summary of the Revised California HERO Program Report.*
2. *Conducted a Public Hearing Regarding the Inclusion of the Counties of Colusa, Mendocino, and Siskiyou Unincorporated areas, for purposes of considering the modification of the Program Report for the California HERO Program to increase the Program Area to include such additional*

jurisdictions and to hear all interested persons that may appear to support or object to, or inquire about the Program.

3. *Adopted WRCOG Resolution Number 01-17; A Resolution of the Executive Committee of the Western Riverside Council of Governments Confirming Modification of the California HERO Program Report so as to expand the Program Area within which Contractual Assessments may be offered.*

B. Transportation Uniform Mitigation Fee (TUMF) Program Activities Update

Christopher Gray reported that a comprehensive update of the Nexus Study is underway, and staff have been working with member jurisdictions to revisit every project currently within the Nexus Study. Growth projections have changed, and Network costs have been reduced by approximately $300 million.

The TUMF Nexus Study Ad Hoc Committee is scheduled to meet later this month and it is anticipated that it will make recommendations in moving forward. A draft Nexus Study will be released in February, providing for a public comment period of 30 days.

The WRCOG Committee structure will review the draft Nexus Study twice; Executive Committee action in anticipated for April. Any fee change will go into effect July / August 2017.

Committee member Kevin Jeffries indicated that he was told by a former City Councilmember who sat on this Committee that when the TUMF Program was created that each city / WRCOG gets 15% / can spend 15% of amount collected, and asked Mr. Gray for clarification.

Mr. Gray responded that the TUMF Administration Plan included a cap of spending revenues at no more than 4% of all revenues for Program administration, which includes primarily staff and consultant wages. Another provision exists in which jurisdictions are allowed to spend a certain amount of money in soft costs for a project. Soft costs include planning, engineering, design, contingency, and program management. Every dollar spent, whether hard or soft, has to be substantiated.

Committee member Jeffries asked if there is an admin fee, per say.

Mr. Gray responded that that is specifically discouraged. Jurisdictions which do not have time sheets cannot request reimbursement.

Committee member Jeffries has concerns with the retail fee, and asked how that can be corrected.

Mr. Gray responded that the TUMF Ad Hoc Committee has directed staff to research a phasing, freezing, or tiered approach. Research indicates that the TUMF Retail fee is substantially higher than neighboring jurisdictions. Current discussions revolve around phasing or freezing the fee, or determine a way to mitigate the Retail fee.

Committee member Mike Naggar asked about the potential impact based upon vehicle miles traveled (VMT) and how it might impact the TUMF and the Nexus Study.

Mr. Gray responded that current projections indicate that the requirement will kick-in in approximately two years after the Office of Planning and Research releases its final set of guidelines. There has been a substantial amount of pushback from the development industry, as well as various Metropolitan Planning Organizations. WRCOG has asked SCAG to assist in funding a study on how to ease the burden of that regulation, as staff views this as a fairly substantial unfunded mandate. Discussions with legal counsel are underway on ways TUMF can be altered to provide mitigation for VMT. Many jurisdictions have level of service requirements; unless that changes, TUMF will continue to provide mitigation for that as well.

Committee member Naggar asked if WRCOG has taken a position that VMT is bad or problematic.

Mr. Gray responded that WRCOG has partnered with RCTC, SCAG, and others. Some aspects of that approach have validity. Retail trips are not as far as house trips. A VMT approach is problematic for some jurisdictions.

Committee member Naggar asked if the Ad Hoc Committee has looked at the difference / dichotomy between the two methods.

Mr. Gray responded that that has not explicitly been discussed with the Ad Hoc Committee; however, it is in the Nexus Study.

Committee member Naggar indicated that he looks forward to future robust conversations on this matter. The old way of doing things is no longer accurate. Adding additional fees to development with properties at zero land base will shut down economic development. We need to start thinking of different ways which promotes economic development.

Committee member Chuck Washington indicated that discussions should include where the bar is set at and what we will get given a certain set of fees. Discussions at SCAG have occurred with regard to state transportation funding, and the belief is that the problem will get worse before it gets better.

Mr. Gray indicated that staff is always available for one-on-one briefings or presentations to City Councils / Boards.

Committee member Naggar asked that the matter of economics in place when TUMF was implemented be discussed. After 2008, equity was wiped off table. At the same time, the cost of infrastructure has not come down.

Mr. Gray responded that fee study includes a series of development and pro formas on what the impact of what fee increases would be on various development types. This information will be packaged and presented as a comprehensive story.

Committee member Naggar would like presented what the situation was in 2003; what progressed; what fell off in 2008; does it still make sense? If not, what changed?

Mr. Gray responded that regardless of the conditions in 2003, we are dealing with today's issues. The critical items are what we are dealing with today and in the foreseeable future.

Action: *Received and filed.*

C. Potential WRCOG Agency Office Relocation

Jennifer Ward reported that this Committee previously directed staff to compare WRCOG's office needs and job functions with that of similar agencies. Since the last presentation to this Committee in August 2016, multiple presentations / discussions have occurred with the Administration & Finance Committee.

The Administration & Finance Committee's preference after several discussions is option 1; the Citrus Towers building. It has been determined that purchasing a building is not the best option at this time due to various liabilities. WRCOG retained broker services of Andy Lustgarten.

With an office move, WRCOG is addressing five major goals: provide sufficient workspace so staff can be productive; the possibility for team collaboration and ample space for meetings; transparency in maintaining the ability to promptly respond to public records act requests and remain compliant with laws in publicizing agendas; to present a professional Agency image; and to provide a regional location for WRCOG's member jurisdictions as well as the many regional partners throughout southern California which WRCOG works with on a regular basis.

The current office provides approximately 5,000 sq. ft. and up to 37 staff can be working in the office at once. WRCOG has only one small conference room which will hold up to six, and does not provide for any teleconference capabilities. All conference room meeting space is dependent upon the availability from other agencies and departments throughout the County Administrative Center (CAC). Staff did a survey of six comparable agencies, and WRCOG falls well below the lowest with regard to square feet per employee.

The Western Municipal Water District (WMWD) has a building for either sale or lease located on Alessandro Boulevard. Supervisor Jeffries also suggested a particular building which is for sale. There are many buildings throughout the subregion; however, from a policy perspective, purchasing a building at this time is not necessarily the best way to go given various potential liabilities.

Ernie Reyna reported that staff examined the amount of time it would take to payback a loan in a purchase situation. Given the Agency's current cash flow, staff felt comfortable with a 10-year loan, but anything greater in length would be a challenge due to uncertainty in revenues collected from current programs. Staff researched interest rates and value of buildings and presented those results. With regard to the WMWD building, if WRCOG did not utilize the entire space, the concern was, does WRCOG become a landlord to utilize the extra space? WRCOG does not have staffing nor expertise in that area, therefore, staff believes leasing is the best option at this time.

Ms. Ward indicated that Option 1, the Citrus Towers, is located approximately one a one half blocks from the current office location. Citrus Towers satisfied the most number of needs with the fewest compromises. Citrus Towers has an entire suite completely vacant with plenty of space for current and future needs. The owner is willing to build to suit and will cover these costs; it is anticipated that the Agency could move in four months. This is a relatively new building so there are little to no concerns with potential construction issues. The owner is requesting a 10-year lease; staff does not see this as a problem as WRCOG has been in the same location for 15 years now. Lease rates are higher compared to other sites as are parking fees for staff. Over 10 years the total lease amount would be approximately $4.4 million.

Mr. Reyna indicated that staff attempted to negotiate the lease rate. Instead of lowering that rate, the Citrus Towers owner offered to build out the entire suite at their expense (approximately 10,000 square feet, plus an additional approximately 2,000 square feet not immediately being utilized). Additionally, the owner would waive the lease for two years on the extra 2,000 square feet. This totaled nearly $1 million in savings. The Agency would be able to move in by approximately May 1, 2017. The overall incentives bring the effective lease rate from $3.10 per sq. ft. to $2.68 per sq. ft. or $2.44 per sq. ft., depending on the total number of square feet WRCOG chooses to lease.

Ms. Ward reported that Option 2 is County-owned space in the Pacific Premiere Bank located across the street from WRCOG's current office location. This location does provide sufficient space for staffing and agency needs; however, the layout of the suite is somewhat awkward and would require more effort in construction customizing. The lease rate would be the same as what WRCOG is currently paying in the CAC. Given that there would be a significant amount of Tenant Improvements (TIs), and potential issues discovered during construction since it is an older building, the move-in timeframe would be significantly longer than four months. The County would not cover the costs of any TI and/or renovations.

Mr. Reyna indicated that there is just over 10k square feet available at the Pacific Premier Bank building, and at the same lease rate as WRCOG's current office location. There are 3 contiguous offices, one of which is off to the side, which makes the build out a little difficult. Staff estimated TIs at approximately $603,000, and would be approximately 12 months before staff could move in. Total costs equate to $2.76 (net effective lease rate) per sq. ft. when TIs (to be paid for by WRCOG) are added back in. Over 10 years the total lease amount would be approximately $3.8 million.

Ms. Ward indicated that Option 3 is the WMWD building of approximately 16,000 sq. ft. and an associated water efficient garden. Staff was interested in the creative options to redesign space for WRCOG's needs. However, the location is far from the current location and staff and the Agency would no longer be able to take advantages the current location provides. The building requires many improvements, such as a new roof, and redesign to make the building compliant with the Americans with Disabilities Act. This would add to TI costs and the timeframe in which the Agency could move.

Option 4 is the purchase of a commercial building in the River Crest location. Again, due to various insurance liabilities, as well as maintenance that would have to be handled in-house, and an uncertain revenue stream, staff does not believe that purchasing a building at this time is in the best interest of the Agency.

Committee member Eugene Montanez asked about the additional cost for parking at the Citrus Towers.

Mr. Reyna responded that WRCOG would absorb the cost difference, and that amount was included in the overall costs presented today.

Committee member Laura Roughton asked if the extra square footage in Option 1 was part of the initial lease, would the Agency be locked in to that space for the remainder of the lease should it desire not to utilize it.

Mr. Renya responded that if that extra space was not built out, it would most likely be able to be returned to the owner.

Andy Lustgarten added that with that additional space, the landlord would build it upfront and provide 26 months of no rent for that space. After which time, WRCOG would then be obligated through the remaining years through the end of the lease agreement. The benefit in having it built out upfront is that the landlord is paying for it. If it is later determined that WRCOG can utilize that space, WRCOG would be responsible for those costs.

Committee member Kevin Bash asked what current lease rate for the next 10 years is at WRCOG's current location.

Mr. Reyna responded that the current lease rate is $2.02 per sq. ft. plus a 3% annual escalator. Over the next 10 years the total lease amount would be approximately $3.8 million (this amount would include maintaining current office space plus an additional 5,000 square feet elsewhere, plus the cost of tenant improvements and furniture.

Committee member Kevin Jeffries indicated that his difficulty is getting over the fact that WRCOG does not want to own a building because of the liabilities associated with owning a building. Committee member Jeffries assumed the Agency had the funding and would not have to assume a mortgage. Committee member Jeffries is disappointed that the second most expensive location is the preferred option. This is unacceptable to most taxpayers and wished that something could have been found which was more affordable or respectable to the taxpayers, who will pay for this one way or another. Committee member Jeffries indicated that he is not happy that WRCOG wants to rent versus own but can respect it, but not at the most expensive location.

Committee member Rita Rogers asked, with regard to the Citrus Towers, if the Administration & Finance Committee approved the option with more or less sq. ft.

Mr. Reyna responded that that option was not available during discussions with the Administration & Finance Committee; however, the lease rate of $3.00 per sq. ft. was. The owner later indicated that the lease rate would remain as is even with the additional incentives.

Committee member Rogers asked if the Agency needs the extra sq. ft.

Ms. Ward responded that staff's believe is because WRCOG has the option to reserve that space rent free for just over two years, and if this Committee feels that the activities and potential agency growth can utilize that space, then staff wanted to provide that information.

Committee member Rogers asked if the Administration & Finance Committee approved the option with less sq. ft.

Ms. Ward responded that yes, it did.

Ward indicated that staff have taken Committee member comments to heart over the past year. WRCOG has outgrown its space over last five years. Staff and the broker completed a broad search to capture the synergies and efficiencies of being close to the CAC and affordable rate.

Committee member Jeffries indicated that staff still has not justified why the most expensive location was picked.

Ms. Ward responded that staff researched five or six options, to include staying at current location. That range of options was presented to Administration & Finance Committee several times. This choice is the result of a years' worth of discussion.

Rick Bishop added that staff put a lot of thought into a purchase option. WRCOG is different than the County and/or a city; the revenue sources are not as consistent or the same. The decision to purchase and not have the ability to make payments is onerous not only to WRCOG but to its member jurisdictions as well. A lease option and the ability to renegotiate / get out of a lease seem more prudent than a purchase. If more programs are created that come with more consistent revenue streams, an option for purchase can be revisited.

Committee member Crystal Ruiz indicated that WRCOG has been very prudent with its money and spending thereof. WRCOG thinks things through very thoroughly and has taken actions which have benefited this Committee. Committee member Ruiz indicated that she understands why WRCOG wants to remain in this area even though it may be the second highest cost. However, staff and the broker negotiated a good deal and the Agency is not spending money frivolously.

Committee member Brenda Dennstedt does not like idea of spending money that does not have to be spent. Committee member Dennstedt would be more than happy to go back to WMWD to discuss lease options. WRCOG initially discussed the option of purchasing; however, WMWD can also consider leasing options.

Mr. Lustgarten responded that 17 various options were evaluated, and more than half were toured. The challenge with older buildings is that, while lease rates may be lower, TIs allowances are significantly less expensive. The options are to same money upfront on capital costs, which would include TIs, and pay a slightly higher lease rate, or receive a lease discount upfront with higher capital costs to construct new space. There is a very limited inventory of 10k + sq. ft. space in downtown Riverside.

Committee member Washington indicated that he recalls when revenue was less predictable. A public agency does not know if the revenue stream will always be there. Many appreciate the convenience of having multiple meetings close to one another.

Committee member Roughton indicated that if the perception in the community is that this is the second most expensive building to rent, perception is important and should be considered. In negotiations, would WRCOG be paying a lower than market rate in the Citrus Towers? Committee member Roughton indicated that she likes the idea of reconsidering the WMWD building. Having a garden and far off vision regarding a sustainability / demonstration center is intriguing. That property would be conducive to that. Committee member Roughton indicated that she is not 100% comfortable supporting today's requested action.

Mr. Lustgarten responded that no other tenant in the Citrus Towers building has received more than $50 in TI, nor have they been offered a build to suit. A $70 construction cost per sq. ft. far exceeds any allowances offered; the rent rate is competitive. No lease agreements at less than $3.10 in have occurred within at least the last 2 years.

Committee member John Denver asked if there just are not many properties for sale in Riverside. If someone owned a building for 10 years, and then had a change in income, the building could then be sold for a profit.

Mr. Lustgarten responded that there are buildings for sale. Mentioned earlier was available space for lease at approximately 10,000 sq. ft. If one owned a building, and in the future needed to sell it, there is no current indication on whether or not a profit would be made.

Ms. Ward indicated that some of the other concerns were not just unforeseen revenue constraints or growth, but additional liabilities with insurance such as someone breaking into the building, etc.

Committee member Bonnie Wright asked how many other tenants in the Citrus Towers rent that large of a space? Generally, the larger the area, the more compensation by a lesser square foot rate.

Mr. Lustgarten responded that that was taken into consideration. Most tenants currently rent a larger amount of square feet. The owner is sensitive to rental rates; the flexibility is in TI and free rent concessions.

Committee member Bash indicated that sometimes a business has to be convenient for employees. A central location taken and access to other buildings should be taken into consideration.

Committee member Brian Tisdale indicated that the Administration & Finance Committee has been discussing this for over one year. Staff are currently in tight quarters.

Committee member Kelly Seyarto indicated that he was on this Committee when this conversation occurred about WRCOG moving into its current location. The move worked out better for the Agency in providing room to grow, and it worked out for the elected officials. The options presented being called the most expensive option is not necessarily the case. Staff has to have a place in order to be effective. Sometimes the cost of trying to make it look like you are saving money costs more. There is also a cost to continue exploring options over and over. We should trust that staff is presenting the best options.

RESULT:	**APPROVED AS RECOMMENDED [UNANIMOUS]**
MOVER:	City of San Jacinto
SECONDER:	City of Corona
AYES:	Banning, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley, Lake Elsinore, Menifee, Moreno Valley, Murrieta, Norco, Perris, Riverside, San Jacinto, Temecula, District 1, District 3, District 5, EMWD, WMWD
ABSENT:	City of Calimesa, City of Wildomar, District 2, Morongo

Action: *Authorized WRCOG to relocate the WRCOG offices to the Citrus Towers, utilizing 10,597 square feet, with a 10-year lease.*

D. Distribution of Round II BEYOND Allocations to Member Jurisdictions

Andrea Howard reported that last year's pilot program provided $1.8 million to member jurisdictions to make progress towards the six goals outlined in WRCOG's Sustainability Framework. More than 30 projects are being funded.

Staff is looking to distribute $4.3 million to its member jurisdictions this year; $1.05 to agency reserves; $700,000 to Agency activities (the Fellowship Program, the Community Choice Aggregation Program, and the Regional Streetlight Program), and $250,000 for a regional economic development initiative. A remaining $2.05 million is for BEYOND allocations. $2 million will go to a central pot of funding for fixed allocations to each member jurisdiction.

The allocations being presented for the central pot of funding cover two primary goals – to avoid the pitfalls of a strictly population-based formula, and to ensure an equitable distribution.

Last year's formula had three population formulas, in which members received a flat allocation plus a small, additional, per-capita allocation. It was later determined that this method created significant inequities in how the funding was distributed across member jurisdictions.

The proposed formula distributes funding through a series of per-capita allocations that incrementally decrease as population increases across five population tiers. A one-time increase to the total allocation of $250,000 is being proposed given that many jurisdictions will be receiving a decrease in funding than last year. Staff is also proposing a minimum for all jurisdictions to receive is $35,000.

Committee member Kevin Jeffries asked if this Committee has already taken action on other funding mentioned in the staff report (Agency reserves, Agency activities, and a regional economic development initiative, Healthy Communities set aside), listed as being prosed today? When did this Committee vote on an increase in reserves and the regional economic development initiative?

Jennifer Ward responded that the remainder categories were approved on June 24, 2016, except $250,000 for regional economic development, which was the result of an Ad Hoc Committee and Administration & Finance Committee recommendation in August 2016. The only proposal being presented for consideration today is for the BEYOND funding

Committee member Laura Roughton clarified that today's action is for a one-year adjustment in the original formula. Moving forward, the formula being presented today should be okay from year to year, barring any increase and/or decrease in revenues.

Ms. Howard responded that this Committee would still have the option to revisit yearly how those allocations are distributed.

Committee member Roughton indicated to make clear that the $35,000 minimum is subject to any increase and/or decrease in funding / revenue.

Ms. Howard responded that funding could be set in that the minimum allocation is not fixed, but the rest of the formula would be.

Committee member Roughton indicated that that would be fine.

Committee member Brian Tisdale indicated that when this Program started last year, the Committee decided to revisit yearly. The funding allocation is not set in stone; allocations can change. The Program should keep that flexibility and not place any restrictions on it.

RESULT:	**APPROVED AS RECOMMENDED [UNANIMOUS]**
MOVER:	City of Lake Elsinore
SECONDER:	City of Temecula
AYES:	Banning, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley, Lake Elsinore, Menifee, Moreno Valley, Murrieta, Norco, Perris, Riverside, San Jacinto, Temecula, District 1, District 3, EMWD, WMWD
ABSENT:	Calimesa, Wildomar, District 2, District 5, Morongo

Actions:

1. *Approved the tiered allocation formula to allocate BEYOND funding for Round II.*
2. *Increased the BEYOND Round II allocation by $252,917.00 from $1.8 million to $2.05 million.*

E. Report from the League of California Cities

Erin Sasse reported that the League has hired a new Executive Director, who will be at the League's upcoming conference later this month.

The Governor is scheduled to release the budget tomorrow at 11 a.m. Revenues are down from projections and this will most likely be a factor in the budget. Anticipated funding includes transportation. SB 1 and AB 1 are packaged very similar to last year at $6 billion – a 12 cent increase to the gas tax; it would end the Board of Equalization's true-up process on the unreliable price based upon the excise tax; an increase of $38 to vehicle registration fees; a $100 increase to registration fees for zero-emission vehicles; a 20 cent increase on the diesel excise tax; $300 million from existing cap-and-trade funds, and $500 million in vehicle weight fees – phased-in over five years.

Affordable housing is a big priority for the State this year. The League does not expect any funding in the Governor's proposal. The Housing & Community Development Department

(HCD) released a housing report with an attached graph which shows the costs of housing when combined with transportation. When transportation was factored in, affordable housing in this subregion was not so affordable. HCD is requesting comments on that report.

This evening's Division has been rescheduled to November 13, 2017.

The Institute for Local Government (ILG) is providing free public engagement training January 31 – February 1, 2017. Attendance is limited. ILG is also hosting a hunger leadership breakfast event on February 25, 2017.

On February 3, 2017, a Division Local Elected Officials training is being held.

The New Mayors and Councilmembers training will be held in 2 weeks.

Chairman Franklin asked for an email of all the dates mentioned.

Ms. Sasse responded that she would.

The League's Public Safety Lobbyist met with the California Department of Corrections and Rehabilitation Secretary Scott Kernan regarding the implementation of Prop 57.

Committee member Mike Naggar indicated that as the focus on the State budget for affordable housing will be driven by the legislature, perhaps that information can be plugged into TUMF discussions.

Rick Bishop responded that there is an existing exclusion for affordable housing to pay TUMF.

Action: *Received and filed.*

8. REPORT FROM THE TECHNICAL ADVISORY COMMITTEE CHAIR

Gary Nordquist indicated that the Technical Advisory Committee was dark in December; the next meeting is scheduled for January 19, 2017.

9. REPORT FROM COMMITTEE REPRESENTATIVES

Debbie Franklin, SCAG Community, Economic, and Human Development (CEHD) representative, reported that the CEHD recently received a presentation on recreation marijuana. The presentation can be found on SCAG's website, and shows the breakdown on revenue and distribution for the cities. The California Air Resources Board presented on implementing different Assembly and Senate Bills regarding continuing and increasing the amount of energy conservation.

10. REPORT FROM THE EXECUTIVE DIRECTOR

Rick Bishop reported that the City of Hemet Regional Streetlight Demonstration tours have been very successful - 4 tours and approximately 100 people in all. One more tour is scheduled for January 19, 2017. Staff is working with eight or nine jurisdictions which are considering actions and participation in the Program during the months of January and February.

11. ITEMS FOR FUTURE AGENDAS

Chairman Franklin would like a status update on vehicle miles traveled.

12. GENERAL ANNOUNCEMENTS

There were no general announcements.

13. NEXT MEETING:

The next WRCOG Executive Committee meeting is scheduled for Monday, February 6, 2017, at 2:00 p.m., at the County of Riverside Administrative Center, 1st Floor Board Chambers.

14. ADJOURNMENT

The meeting adjourned in memory of Supervisor John J. Benoit at 3:55 p.m.

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Item 4.B

Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **2nd Quarter Draft Budget Amendment for Fiscal Year 2016/2017**

Contact: **Ernie Reyna, Chief Financial Officer, reyna@wrcog.cog.ca.us, (951) 955-8432**

Date: **February 6, 2017**

The purpose of this item is to *share WRCOG's 2nd Quarter Budget Amendments for Fiscal Year (FY) 2016/2017, as identified in the attachment to this staff report, which include no net changes to both the General Fund and Transportation Department, and a net expenditure increase to the Energy Department that will be offset by a reimbursable grant for Electric Vehicle (EV) chargers. A summary of proposed amendments by Department is listed below.*

Requested Action:

1. Approve the 2nd Quarter Draft Budget Amendment for Fiscal Year 2016/2017.

General Fund: The Administration's single largest line item increase to expenditures is for the addition of criminal insurance of $9,280, and with all additions in this Program, increases to expenditures will amount to $20,396, but will be offset by a decrease in the Membership Dues line item in the same amount. For the Government Relations Program, the single largest increase in expenditures is for computer supplies of $1,012, and with the other increases in various line items, the total amount of increase is $2,131, but will be offset by a decrease to fringe benefits in the same amount.

Net Expenditure Increase to the General Fund: ***$0***

Transportation Department: The TUMF Program's largest increase to expenditures is legal which will need to be increased by $20,519, and with the other increases in expenditures, the total increase will be $21,993. This amount will be offset by decreasing the amount of consulting by the same amount of $21,993. The Active Transportation Program will be increasing legal fees by $1,905, which will be offset by a decrease to consulting labor of the same amount. Lastly, the Clean Cities Program will have increases to its Overhead, Fringe Benefit, and Cell Phone line items of $3,849, but this will be offset in reductions to the Supplies-Materials line item of the same amount.

Net Expenditure Increase to Transportation Department: ***$0***

Energy Department: Within the Energy Department, WRCOG purchased six electric vehicle (EV) chargers in three different locations within the subregion to assist member agencies. The cost of those chargers was $49,605, and is reimbursable up to $30,000 by the Air Quality Management District (AQMD). In addition, the Regional Street Lights Program will increase its expenditures by $8,872, and, coupled with the Energy Department, expenditures will increase by $60,248, of which, $30,000 will be reimbursed by AQMD. The Southern California Edison Program will be increasing its revenue by $10,643, leaving a net expenditure increase of $49,605 in the Energy Department, and will reflect the $30,000 reimbursable when received.

Net Expenditure Increase to Energy Department: ***$49,605***

<u>Prior Actions</u>:

<u>January 19, 2017</u>: The Technical Advisory Committee recommended that the Executive Committee approve the 2nd Quarter Draft Budget Amendment for Fiscal Year 2016/2017.

<u>January 11, 2017</u>: The Administration & Finance Committee recommended that the Executive Committee approve the 2nd Quarter Draft Budget Amendment for Fiscal Year 2016/2017.

<u>Fiscal Impact</u>:

General Fund: No Revenue / Expenditure / Increase or Decrease

Transportation: No Revenue / Expenditure / Increase or Decrease

Energy: Net Expenditure Increase of $49,605

Overall, FY 2016/2017's Budget for the 2nd Quarter will increase expenditures for the Agency by $49,605, of which, $30,000 will be reimbursed through an AQMD grant, leaving a balance of $19,605. This increase in expenditures will be offset by future HERO revenues in the Energy Department.

<u>Attachment</u>:

1. Annual Budget for the Year Ending June 30, 2017, with 2nd Quarter Amendments.

Item 4.B

2nd Quarter Draft Budget Amendment for Fiscal Year 2016/2017

Attachment 1

Annual Budget for the Year Ending June 30, 2017, with 2nd Quarter Amendments

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Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Total General Fund

		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Expenditures			
	Wages and Benefits			
61000	Fringe Benefits	49,793	20,747	**(2,131)**
	Total Wages and Benefits	49,793	20,747	**(2,131)**
	General Operations			
65101	General Legal Services	-	88	**88**
73003	WRCOG Auto Fuels Expense	178	329	**500**
73004	WRCOG Auto Maintenance Expense	16	33	**17**
73102	Parking Validations	-	105	**105**
73107	Event Support	1,241	1,561	**320**
73108	General Supplies	-	188	**188**
73109	Computer Supplies	425	1,437	**1,012**
73113	Membership Dues	35,000	6,620	**(20,171)**
73114	Subscriptions/Publications	4,783	4,864	**81**
73115	Meeting Support/Services	1,100	1,608	**508**
73116	Postage	-	53	**53**
73204	Communications - Cellular	38	177	**139**
73206	Communications - Computer Server	17,000	18,271	**1,271**
73302	Equipment Maintenance - Computers	3,267	8,151	**4,884**
73405	Insurance - Gen/Business	62,970	72,250	**9,280**
73407	WRCOG Auto Insurance	345	1,570	**1,225**
85101	Consulting Labor	20,000	22,630	**2,630**
	Total General Operations	-	139,935	**2,130**
	Total Net Expenditure Increase/(Decrease)			**$ 0**

Western Riverside Council of Governments
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Department: Administration		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Expenditures			
	General Operations			
73003	WRCOG Auto Fuels Expense	178	329	**500**
73004	WRCOG Auto Maintenance Expense	16	33	**17**
73113	Membership Dues	34,750	6,145	**(20,396)**
73114	Subscriptions/Publications	4,783	4,864	**81**
73115	Meeting Support/Services	1,100	1,608	**508**
73206	Communications - Computer Srv	17,000	18,271	**1,271**
73302	Equipment Maintenance - Computers	3,267	8,151	**4,884**
73405	Insurance - Gen/Business	62,970	72,250	**9,280**
73407	WRCOG Auto Insurance	345	1,570	**1,225**
85101	Consulting Labor	20,000	22,630	**2,630**
	Total General Operations	-	135,851	**(0)**
	Total Net Expenditure Increase/(Decrease)			**$ (0)**

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Government Relations (70)		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Expenditures			
	Wages and Benefits			
61000	Fringe Benefit	49,793	20,747	**(2,131)**
	Total Wages and Benefits	49,793	20,747	**(2,131)**
	General Operations			
65101	General Legal Services	-	88	**88**
73102	Parking Validations	-	105	**105**
73107	Event Support	1,241	1,561	**320**
73108	General Supplies	-	188	**188**
73109	Computer Supplies	425	1,437	**1,012**
73113	Membership Dues	250	475	**225**
73116	Postage	-	53	**53**
73204	Communications Cellular	38	177	**139**
	Total General Operations	1,954	4,085	**2,131**
	Total Net Revenue Increase/(Decrease)			**$ (0)**

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Transportation (Summary)		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Expenditures			
	Wages and Benefits			
61000	Fringe Benefit	3,406	4,278	**872**
	Total Wages and Benefits	3,406	4,278	**872**
	General Operations			
63000	Overhead Allocation	12,500	10,000	**2,500**
65101	General Legal Services	200,000	222,423	**22,424**
73113	Membership Dues	-	670	**670**
73114	Subcriptions/Publications	-	-	**-**
73115	Meeting Support/Services	-	-	**-**
73116	Postage	-	-	**-**
73117	Other Household Expenditures	112	213	**101**
73119	Storage			
73120	Printing Services	-	-	**-**
73122	Computer Hardware	-	-	**-**
73201	Communications-Regular			
73203	Communications-Long Distance			
73204	Communications-Cellular	285	762	**477**
73206	Communications-Comp Sv			
73209	Communications-Web Site	-	-	**-**
73301	Equipment Maintenance - General	-	-	**-**
73405	Insurance - General/Business Liason			
73502	County RIFMIS Charges			
73601	Seminars/Conferences	1,000	1,123	**123**
73605	General Assembly Expenditures			
73611	Travel - Mileage Reimbursement	-	-	**-**
73612	Travel - Ground Transportation	-	-	**-**
73613	Travel - Airfare	-	-	**-**
73620	Lodging	1,000	1,066	**66**
73630	Meals	614	1,128	**514**
73640	Other Incidentals	-	-	**-**
73650	Training	-	-	**-**
73703	Supplies/Materials	10,000	-	**(3,849)**
73704	Newspaper Ads			
73705	Billboard Ads	-	-	**-**
73706	Radio & TV Ads			
85100	Direct Costs			**-**
85101	Consulting Labor	803,500	212,374	**(23,898)**
85102	Consulting Expenses	-	-	**-**
90101	Computer Equipment Purchases	-	-	**-**
90201	Office Equipment Purchase	-	-	**-**
97001	Operating Transfer Out	-	-	
97005	Benefits Transfer Out	-	-	
	Total General Operations	1,029,011	449,760	**(872)**
	Total Net Revenue Increase/(Decrease)			**$ (0)**

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Transportation (TUMF - 1148)		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Expenditures			
	General Operations			
65101	General Legal Services	200,000	220,519	**20,519**
73113	Membership Dues	-	670	**670**
73117	Other Household Expenditures	112	213	**101**
73601	Seminars/Conferences	1,000	1,123	**123**
73620	Lodging	1,000	1,066	**66**
73630	Meals	614	1,128	**514**
85101	Consulting Labor	643,500	207,852	**(21,993)**
	Total General Operations	846,226	432,571	**(0)**
	Total Net Expenditure Increase/(Decrease)			**$ 0**

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
Department: Transportation (Active Transportation Program - 2030)				
	Expenditures			
	General Operations			
65101	General Legal Services	-	1,905	**1,905**
85101	Consulting Labor	160,000	4,522	**(1,905)**
	Total General Operations	160,000	6,427	**-**
	Total Net Expenditure Increase/(Decrease)			**$ -**

Western Riverside Council of Governments
Annual Budget
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Department: Environmental (Clean Cities - 1010)		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Expenditures			
	Wages and Benefits			
61000	Fringe Benefit	3,406	4,278	**872**
	Total Wages and Benefits	3,406	4,278	**872**
	General Operations			
63000	Overhead	12,500	10,000	**2,500**
73204	Communications-Cellular	285	762	**477**
73703	Supplies/Materials	10,000	-	**(3,849)**
	Total General Operations	22,785	10,762	**(872)**
	Total Net Expenditure Increase/(Decrease)			**$ 0**

Western Riverside Council of Governments
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Department: Energy (Summary)		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Revenues			
40609	SCE Phase Three	-	10,643	**10,643**
	Total Revenues	-	10,643	**10,643**
	General Operations			
65101	General Legal Services	38,173	55,937	**17,764**
65507	Commissioners Per Diem	1,500	-	**450**
73107	Event Support	23,000	15,766	**3,772**
73113	Membership Dues	-	265	**265**
73114	Subcriptions/Publications	273	585	**312**
73115	Meeting Support/Services	37	103	**66**
73116	Postage	-	2	**2**
73117	Other Household Expenditures	242	310	**68**
73126	EV Charging Equipment	-	49,605	**49,605**
73405	Insurance - General/Business Liason	175	595	**420**
73601	Seminars/Conferences	5,163	299	**(2,101)**
73611	Travel - Mileage Reimbursement	425	1,093	**668**
73613	Travel - Airfare	2,100	1,937	**837**
73620	Lodging	600	-	**(600)**
73630	Meals	148	176	**28**
73640	Other Incidentals	1,500	2,224	**724**
73650	Training	4,000	-	**(2,000)**
85101	Consulting Labor	619,793	410,044	**(10,032)**
	Total General Operations	697,129	538,942	**60,248**
	Total Net Expenditure Increase/(Decrease)			**$ 49,605**

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Energy (WRCOG HERO - 2006)		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Expenditures			
	General Operations			
65101	General Legal Services	25,000	33,024	**8,024**
73640	Other Incidentals	1,500	2,224	**724**
85101	Consulting Labor	469,793	277,959	**(9,624)**
	Total General Operations	496,293	313,207	**(876)**
	Total Net Expenditure Increase/(Decrease)			**$ (876)**

Western Riverside Council of Governments
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For the Year Ending June 30, 2017

Department: Energy (SCE - 2010)		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Expenditures			
	General Operations			
65101	General Legal Services	750	4,307	**3,557**
73107	Event Support	20,000	5,437	**(3,557)**
	Total General Operations	20,750	9,744	**0**
	Total Net Expenditure Increase/(Decrease)			**$ 0**

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Energy (Regional Street Lights - 2026)		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Expenditures			
	General Operations			
65101	General Legal Services	12,423	18,547	**6,124**
73107	Event Support	3,000	4,972	**1,972**
73114	Subcriptions/Publications	273	410	**137**
73611	Travel - Mileage Reimbursement	425	1,035	**610**
73630	Meals	148	176	**28**
	Total General Operations	16,269	25,141	**8,872**
	Total Net Expenditure Increase/(Decrease)			**$ 8,872**

Western Riverside Council of Governments
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For the Year Ending June 30, 2017

Department: Energy (Community Choice Aggregation - 2040)		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Expenditures			
	General Operations			
73113	Membership Dues	-	265	**265**
73115	Meeting Support/Services	37	103	**66**
73116	Postage	-	2	**2**
73601	Seminars/Conferences	663	-	**(663)**
73613	Travel - Airfare	600	1,937	**1,337**
73620	Lodging	600	-	**(600)**
85101	Consulting Labor	150,000	132,085	**(408)**
	Total General Operations	1,300	134,393	**(0)**
	Total Net Expenditure Increase/(Decrease)			**$ (0)**

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Energy (SCE Phase III - 2070)		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Revenues			
40609	SCE Phase Three	-	10,643	**10,643**
	Total Revenues	-	10,643	**10,643**
	Total Net Revenue Increase/(Decrease)			**10,643**

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Base (Energy Dept - 2100)

		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Expenditures			
	General Operations			
65101	General Legal Services	-	59	**59**
73107	Event Support	-	5,357	**5,357**
73114	Subcriptions/Publications	-	175	**175**
73126	EV Charging Equipment	-	49,605	**49,605**
73601	Seminars/Conferences	1,500	299	**(500)**
73613	Travel - Airfare	1,500	-	**(500)**
73650	Training	4,000	-	**(2,000)**
	Total General Operations	7,000	55,494	**52,195**
	Total Net Expenditure Increase/(Decrease)			**$ 52,195**

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Spruce (2102)		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Expenditures			
	General Operations			
73611	Travel - Mileage Reimbursement	-	58	**58**
	Total General Operations	-	58	**58**
	Total Net Expenditure Increase/(Decrease)			**$ 58**

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Energy (California HERO - 5000)		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	**Amendment Needed 12/31/2016**
	Expenditures			
	General Operations			
65507	Commissioners Per Diem	1,500	1,950	**450**
73117	Other Household Expenditures	242	310	**68**
73405	Insurance - General/Business Liason	175	595	**420**
73601	Seminars/Conferences	3,000	-	**(938)**
	Total General Operations	4,917	2,855	**(0)**
	Total Net Expenditure Increase/(Decrease)			**$ (0)**

Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **Flabob Airport TUMF Appeal**

Contact: **Christopher Gray, Director of Transportation, gray@wrcog.cog.ca.us, (951) 955-8304**

Date: **February 6, 2017**

***The purpose of this item is to** request that Committee members approve a TUMF appeal from the Flabob Airport in the City of Jurupa Valley.*

Requested Action:

1. Approve the appeal consistent with the recommendation from staff and the Administration & Finance Committee.

WRCOG's Transportation Uniform Mitigation Fee (TUMF) Program is a regional fee program designed to provide transportation and transit infrastructure that mitigates the impact of new growth in Western Riverside County. Each of WRCOG's member jurisdictions and the March JPA participates in the Program through an adopted ordinance, collects fees from new development, and remits the fees to WRCOG. WRCOG, as administrator of the TUMF Program, allocates TUMF to the Riverside County Transportation Commission (RCTC), groupings of jurisdictions – referred to as TUMF Zones – based on the amounts of fees collected in these groups, and the Riverside Transit Agency (RTA).

The TUMF Administrative Plan serves as the governance document for the TUMF Program and outlines various roles and responsibilities for WRCOG, the Riverside County Transportation Commission, member agencies, and other parties involved in the TUMF Program. The TUMF Administrative Plan contains a provision in which a building permit applicant can appeal any TUMF assessment, provided that the process outlined in the Administrative Plan is followed.

TUMF Appeal

The TUMF Program allows an applicant to appeal the fee under certain circumstances. Section X of the TUMF Administrative Plan (Attachment 1) outlines the appeal process.

The Tom Wathen Center (Applicant), owner of the Flabob Airport in the City of Jurupa Valley, received approximately 57 hangars from the Rialto Airport, which is now closed. The operators of the Flabob Airport intend to install these hangers for use at the Airport. As these hangers would be new buildings at the Airport, they would be subject to TUMF.

Both the Airport operator and the City questioned whether TUMF would be applicable to this use, which WRCOG indicated that it would be because the project did not fall under one of the TUMF exemptions outlined TUMF Ordinance and Administrative Plan. Therefore, the City assessed the TUMF for this project as industrial buildings. The applicant appealed their TUMF assessment first to the City (which denied the appeal) and then to WRCOG (Attachment 2). The appeal was presented to the Administration & Finance Committee pursuant to the procedures for TUMF appeals.

The Applicant's TUMF appeal is in two parts:

1. The project should be exempt from TUMF because it is a public use facility, regardless of ownership or operation by a government entity;
2. The TUMF Administrative Plan should be updated to revise the language for the government/public building exemption to include public-use airports, however owned, and which hold a current permit from the Division of Aeronautics of Caltrans.

While the City denied the appeal, as per the current requirements, the City Council and City staff is in support of the TUMF appeal for a variety of reasons (Attachment 3). The main issue in question is whether an airport is a public facility (which is exempt from TUMF) or a private use (which is subject to TUMF). Currently, government / public buildings, public schools, and other public facilities are exempt from TUMF per the Administrative Plan. This exemption ensures that WRCOG member jurisdictions are not assessing fees on public facilities that they are constructing or operating.

After reviewing the information provided by the Applicant and the City, WRCOG staff would consider an airport to be a public facility and therefore TUMF exempt. If the Executive Committee concurs with the recommendation to approve this appeal, staff will be updating the Administrative Plan to exempt airports from TUMF based on the following criteria:

- These airports are public use facilities; and
- These airports are appropriately permitted by Caltrans or other state agency.

Approving this appeal will result in a loss to the TUMF Program of approximately $140,000. However, staff does not anticipate a significant number of projects satisfying this exemption as it is very narrowly drawn and the likelihood of additional public-use airports in Riverside County is minimal. Therefore, there is limited, long-term financial impact on the TUMF Program.

At its January 11, 2017, meeting, the Administration & Finance Committee recommended that the Executive Committee approve the TUMF appeal consistent with staff's recommendation.

Prior Action:

January 11, 2017: The Administration & Finance Committee 1) approved staff's recommendation to approve the appeal; and 2) recommended that the Executive Committee approve the appeal consistent with staff's recommendation.

Fiscal Impact:

Based on the outcome of the appeal, $140,000 in TUMF revenues may not be received in Fiscal Year 2016/2017.

Attachments:

1. TUMF Administrative Plan Appeal Process.
2. Flabob Airport TUMF Appeal Letter.
3. City of Jurupa Valley TUMF Letter.

Item 4.C

Flabob Airport TUMF Appeal

Attachment 1

TUMF Administrative Plan Appeal Process

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the one percent administrative salaries and benefit cap) unless otherwise directed by the Executive Committee.

3. Beginning July 1, 2006, WRCOG will take the administrative component from the revenue collected based on the total fee obligation inclusive of executed credit agreements.
4. Beginning July 1, 2006, all CFD's, SCIP and other financing mechanisms will pay the maximum (4%) administrative component in cash to WRCOG. When the administrative component is less than 4% then the surplus revenue will be allocated in accordance to their adopted percentages to the Multi-species Habitat Conservation Plan, RCTC, RTA and the Zones.
5. For refunds, whether it is because the project is no longer going forward or expiration of building permits (where no construction has commenced), the applicant is entitled to a refund less the administrative component. Refunds will be processed based on available cash and will not take precedence over the projects identified as funded on the approved TIP. Refunds will however take precedence over the addition of new projects to the TIP.

X. Appeals. Appeals shall only be made in accordance with the provisions of this Section X.

A. Persons or Entities Who Having Standing to Appeal. No person or entity shall have standing to avail themselves of this Section X, except those persons or individuals who are responsible for paying the TUMF and have an unresolved appealable issue or matter.

B. Appealable Issues and Matters. No issue or matter shall be heard or reviewed under this Section X unless the issue or matter is appealable. An issue or matter is appealable, if a qualified person or entity ("Appellant") has a good-faith dispute directly related to Appellant's Property ("TUMF Dispute") regarding (i) the amount of Appellant's TUMF obligation; (ii) the administration of TUMF Credits; (iii) exemption of Appellant's property from the TUMF Program; or (iv) administration of TUMF reimbursements.

C. Appeal Process.

1. If a qualified person or entity has a TUMF Dispute, he or she shall first attempt to resolve the dispute informally with the staff of the local jurisdiction. If the TUMF Dispute remains unresolved after a reasonable attempt to address it at the local level, the qualified person or entity may submit a written appeal to the appropriate department of the local jurisdiction. The written appeal shall thoroughly identify the TUMF Dispute. The Appellant and staff from the local jurisdiction shall attempt to resolve the issue within thirty (30) days of the local jurisdiction's receipt of the appeal. At the request of the local jurisdiction, or on its own accord, WRCOG staff may also participate in such discussions. At the conclusion of the thirty (30) day period, staff of the local jurisdiction shall render a written decision on the appeal. If the staff of the local jurisdiction determines the issue or matter is not a TUMF Dispute, the written appeal shall be rejected. Staff's decision shall be provided in writing to the Appellant. In such cases, if the Appellant desires further review from the Board of Supervisors/City Council of the affected local jurisdiction, the

Appellant must submit a written request for review to the Clerk of the Board/City Council within five (5) days of receiving staff's written decision. The decision of the Board/City Council shall be forwarded to the WRCOG Executive Committee in the same manner set forth in Paragraph 2 of this Section.

2 The issue or matter shall be heard by the Board of Supervisors/City Council of the affected local jurisdiction; provided, the Appellant submits a written request for further review to the Clerk of the Board/City Council within five (5) days of Appellant's receipt of the local jurisdiction's written decision regarding the Appellant's appeal. The Board/City Council shall forward its written decision to WRCOG for review and concurrence. If the WRCOG Executive Committee disagree with the decision of the City Council/Board of Supervisors, the WRCOG Executive Committee shall determine a proper course of action and notify the jurisdiction of its findings. The WRCOG Administration & Finance Committee may, at its discretion or at the request of the Executive Committee, provide its recommendation to the Executive Committee on the appeal.

XI. **Arbitration.** When there is a dispute among the Zone members that cannot be resolved and prevents the adoption of a project prioritization schedule, the matter shall be forwarded to the WRCOG TAC and WRCOG Executive Committee for a determination. Once the WRCOG Executive Committee takes action on the issue the decision is final.

If there is a dispute at the WRCOG Executive Committee level regarding project prioritization of a specific project(s) and a consensus cannot be reached, that project shall be tabled until such time as new information is presented and the matter can be resolved.

XII. **TUMF Program Amendments.** WRCOG shall undertake a review of all components of the TUMF Program in accordance with Government Code Section 66000 et seq. and other applicable laws, and, if necessary, recommend Program amendments and/or adjustments. Amendments to the Administrative Plan will be subject to the approval of the WRCOG Executive Committee. Amendments required to the TUMF Program Ordinance shall be approved by each participating jurisdiction, acting on recommendations provided by the WRCOG Executive Committee. The review shall consider whether future administration costs to participating jurisdictions are needed.

1. **TUMF Network Revisions**: The TUMF Network is reviewed and revised at regular Nexus Study updates, with minor adjustments such as name changes, distances, and other errors that may be found from time to time occurring on a more frequent basis. However, there could be instances when certain assumptions were made during a Nexus Update that did not come to fruition that should be addressed. The primary cause is when a new city is incorporated and inherits the TUMF Network, which may not reflect the new jurisdiction's General Plan or priorities; another example is if a jurisdiction needs to "trade" a facility on the Network due to a rapid change in development patterns that should not wait for the normal revision cycle.

For new cities there would be an opportunity to review the TUMF Network with WRCOG staff to ensure that the Network identifies their priorities and allows

Item 4.C
Flabob Airport TUMF Appeal

Attachment 2
Flabob Airport TUMF Appeal Letter

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Flabob Airport LLC
The Tom Wathen Center

November 8, 2016

Mr. Rick Bishop, Executive Director
Western Riverside Council of Governments
4080 Lemon Street
3rd Floor, MS1032
Riverside, CA 92501-3609

Dear Mr. Bishop:

The Tom Wathen Center, the nonprofit 501(c)(3) corporation which owns Flabob Airport, requests that the WRCOG Executive Committee reconsider two changes to the TUMF Administrative Manual, made on June 24, 2016. These changes (Note 1) limited the "public facilities" exemption to "public facilities that are owned and operated by a government entity." We believe that this is an unsound policy when applied to public-use airports, regardless of ownership, and that public-use airports were not considered when these changes were adopted.

Generally, airports are classified by their use, rather than by their ownership. The following are examples:

- Riverside County defines "airport" by its use, in Ordinance 448: ""Airport" means any area of land or water designed and set aside for the landing and taking off of aircraft and *utilized or to be utilized in the interest of the public* for such purposes." (Italics added)

- The Development Fee Act, Government Code Sections 66000-66008. includes the following:
  "(d) "Public facilities" includes public *improvements*, public services, and community amenities."
  Section 66002 (c) includes the following:
  "(c) "Facility" or "improvement," as used in this section, means any of the following:

  * * *

  (6) Transportation and transit facilities, including but not limited to streets and supporting improvements, roads, overpasses, bridges, harbors, ports, *airports*, and related facilities." (Italics added)

  - The State of California requires the same permit for all public-use airports, whether owned by a government entity, a nonprofit corporation, or a private

1 Exhibit E, paragraph Q, and Exhibit F, paragraph 2.

4130 Mennes Avenue Jurupa Valley, CA 92509 Tel: (951) 683-2309 Fax: (951) 684-2309

entity: Operation Without Permit, PUC 21663. “It is unlawful for any political subdivision, any of its officers or employees, or any person to operate an airport unless an appropriate airport permit required by rule of the Department [now the Division of Aeronautics of Caltrans] has been issued by the Department and has not subsequently been revoked.”

- California regulations define a “Public Use Airport” by its function, without regard to its ownership. CCR 3527: “(q) Public-Use Airport: An airport that is open for aircraft operations to the general public and is listed in the current edition of the Airport/Facility Directory that is published by the National Ocean Service of the U.S. Department of Commerce.” Flabob Airport meets all requirements of this definition, and is listed as a public-use airport in the current Federal Aviation Administration Airport/Facility Directory.
- In the Jurupa Valley General Plan, the land use designation for Flabob Airport is “PF-Public Facilities.” The definition is: “Public Facility Area Plan Land Use Designation: Uses within the Public Facilities land use designation provide essential support services to the County. These uses include *airports*, landfills, flood control facilities, utilities, schools, and other such facilities.” (Italics added.)
- Flabob Airport is listed as a “Regional” public-use airport in the most recent (2013) California Aviation System Plan, Inventory Element, of the Caltrans Division of Aeronautics. Other airports classified as “Regional” in the WRCOG region include Corona Municipal Airport, French Valley Airport, Hemet-Ryan Airport, and Riverside Municipal Airport. All except Flabob are owned by counties or municipalities; but the classification is based on public function, not ownership.

These are among the reasons why we believe it is not sound policy to exclude public-use airports from the TUMF on the basis of ownership. Such airports play an important role in an integrated transportation system regardless of ownership.

The background of this request is that Flabob Airport received approximately 55 airplane hangars from the defunct Rialto Municipal Airport, and is in the process of installing them at Flabob, approximately doubling the available number of hangars. Our request for a waiver of TUMF as a “public facility” was denied by the Jurupa Valley Building Official, and by the Jurupa Valley City Council. These denials were mandated by the change in the WRCOG TUMF Administrative Manual, limiting the “public facility” exemption to government-owned facilities. At the City Council hearing of October 20 on this matter, the following occurred:

“16. COUNCIL BUSINESS
A. CONSIDERATION OF THE APPEAL OF FLABOB AIRPORT FOR A WAIVER OF TRANSPORTATION UNIFORM MITIGATION FEES FOR HANGER EXPANSION AT FLABOB AIRPORT, 4130 MENNES AVENUE, JURUPA VALLEY

Council Member Hancock announced that because his business is located inside the Flabob Airport, he would recuse himself from this matter. He stepped down from the dais and left the Council Chamber.

Keith Clarke, Building Official, presented the staff report.
John Lyon, Corporate Secretary of the Tom Wathen Center that operates the Flabob Airport presented a written statement explaining why they concur with staff's recommendation. He asked the City to support their request to WRCOG to reconsider their recent policy change and to exempt public use airports.
Discussion followed.
A motion was made by Council Member Johnston, seconded by Mayor Pro Tem Lauritzen, to 1) deny the waiver request; 2) deny the appeal of the building classification, and 3) submit a letter to WRCOG supporting Flabob Airport's request for an appeal.

Ayes: Berkson, Johnston, Lauritzen, Roughton
Noes: None
Absent: Hancock"

Accordingly, Flabob Airport has the full support of the Jurupa Valley City Council.

The changes we request are:

Exhibit E, paragraph Q, add the underlined language:

"Q. Government/public buildings, public schools, and public facilities that are owned and operated by a government entity<u>, and public-use airports, however owned, which hold a current permit from the Divison of Aeronautics of Caltrans,</u> in accordance with Section G. subsection Iv of the model TUMF Ordinance."

Exhibit F, Paragraph 2, add the underlined language:

"2. Government/public buildings, public schools, and public facilities that are owned and operated by a government entity<u>, and public-use airports, however owned, which hold a current permit from the Divison of Aeronautics of Caltrans,</u> in accordance with Section Q of Exhibit E of the Administrative Plan and Section G. subsection Iv of the model TUMF Ordinance."

We believe that this change will in no way undermine the purpose of the TUMF. As noted, the addition of the new hangars at Flabob will approximately double the existing hangar capacity. We conducted a detailed survey, three times daily for seven days, recording all motor vehicles at Flabob Airport and their purpose in visiting. This survey showed that there were approximately seventeen daily trips generated by users of aircraft hangars. Therefore, we anticipate that doubling the hangar capacity will add about that number of additional trips, an insignificant amount.

We will be pleased to meet with you or your staff to provide any more information or to discuss this further.

Very truly yours,

John D. Lyon, Corporate Secretary and Trustee

Cc: Hon. Laura Roughton, Mayor

4130 Mennes Avenue Jurupa Valley, CA 92509 Tel: (951) 683-2309 Fax: (951) 684-2309

Mr. Gary Thompson, City Manager

Item 4.C

Flabob Airport TUMF Appeal

Attachment 3

City of Jurupa Valley TUMF Letter

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December 5, 2016

Western Riverside Council of Governments
Attn: Executive Committee
4080 Lemon Street
3rd Floor, MS 1032
Riverside, CA 92501-3609

RE: FLABOB AIRPORT REQUEST FOR WAIVER OF TUMF FEES

At the October 20, 2016 Jurupa Valley City Council meeting, the appeal for waiver of TUMF fees for Flabob Airport in the amount of $139,368 for their associated facility improvements was denied. This decision was made as a result of a written determination by WRCOG staff that this facility was not exempt, due to it being a privately owned facility versus a "public facility" (government owned). Although the City Council denied the fee waiver based on the decision by WRCOG staff, the City Council and City staff feel that the impact on regional transportation should not be determined based on ownership, rather it should be based on the technical aspects alone. This airport serves as a municipal and public airport in the same context as a regular government entity owned municipal airport.

City staff has been assisting the owners of Flabob Airport for several years in order to process the permits for 57 hangars obtained from the closure of the Rialto Airport, and to be re-constructed at this location, which are the subject of the TUMF fees in question. The City Council understands that this airport is financially challenged, as it is owned and operated by a non-profit organization, with payment of these fees placing an additional burden on their ability to maintain a cohesive operation. Recently, the Jurupa Unified School District waived the payment of their fees because they determined that this use was unique, and in recognition of the value that this airport provides to the region.

In light of the above, and in support of the documented reasons submitted by Flabob Airport in support of their waiver request, the City Council encourages members of the WRCOG Executive Committee to approve the TUMF fee waiver appeal for this facility.

If you have any questions regarding this matter, please feel free to call me at 951-332-6464.

Sincerely,

Gary Thompson
City Manager

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Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **RIVCOconnect Broadband Initiative**

Contacts: **David Littell, Information Technology Officer II, County of Riverside, DLittell@RIVCO.ORG, (951) 955-3687**

Date: **February 6, 2017**

***The purpose of this item is to** adopt a Resolution in support of Riverside County Information Technology's (RCIT) broadband initiative – "RIVCOconnect." This initiative seeks to remove the road blocks that obstruct service providers from building out current broadband infrastructure. The Resolution does not, in any way, place any legal commitment upon the signatories.*

Requested Action:

1. Adopt WRCOG Resolution Number 02-17; A Resolution of the Executive Committee of the Western Riverside Council of Governments to Support Riverside County Information Technology's Broadband Initiative – RIVCOconnect.

RIVCOconnect is a Riverside County initiative supported by the Riverside County Board of Supervisors and Executive Office, and led by RCIT, that seeks to invite the private sector to work in cooperative fashion and create partnerships to deliver Broadband services Countywide.

Background

Throughout Riverside County – as well as across most of the country as a whole – large segments of our residents have no access to high-speed internet service. Most of these – approximately 58% of the total population living in these areas – reside in rural, unincorporated, and tribal communities. These Riverside County residents, numbering nearly 100,000 in total, are the individuals most likely to fall behind in the 21st Century world of information, the 21st Century economy, and occupy that area known as the Digital Divide.

RIVCOconnect is a Riverside County initiative, supported by the Riverside County Board of Supervisors and Executive Office, and led by RCIT, that seeks to remove the road blocks that obstruct service providers from building out the current infrastructure. RIVCOconnect seeks to invite the private sector, either incumbent vendors or business entities new to the County, to work in a cooperative fashion and create partnerships to deliver Broadband services Countywide at speeds of 1 Gbps and above. It is also the goal of RIVCOconnect that this service be provided to all residents at an affordable cost, one that allows all residents to access high-speed connections to information, entertainment, health care, government services, employment opportunities, and educational growth. The RIVCOconnect Initiative is working toward the development of expedited County permitting procedures, providing low-cost locations for fiber shelters, telecomm cabinets, pole boxes and curbside utility vaults, and offering incentives such as anchor tenancy and asking the same of our municipal and local community partners who will be joining us in our efforts.

It is not the intent of the County of Riverside that this new Countywide Gigabit Network will be owned and operated in the public realm. Rather, it is the goal of RIVCOconnect and the Board of Supervisors that the private sector will see the new opportunities being unveiled that will lead to the largest such high-speed

Broadband network in the country. RIVCOconnect will pave the way for economic growth, educational advancement, rising employment in professional and technical lines of business, and increased security for the County's seniors.

Purpose of the Resolution

The RIVCOconnect team is asking the cities and Tribal Nations in Riverside County to sign a Resolution of Support for Riverside County's Broadband Fiber to the Premise Master Plan (The Master Plan can be found online at https://data.countyofriverside.us/Administrative-and-Fiscal-Services/Broadband-Master-Plan-For-Riverside-County/gyry-nit5). The resolution will not, in any way, place any legal commitment upon the signatories, nor does it place said jurisdictions under any restraint regarding their own pursuit of high-speed broadband services within their own boundaries. No out of pocket expenditures or budgetary outlays are asked for, as this project seeks only to clear the path and present an inviting atmosphere for the private sector to bid on this build-out of infrastructure and the affordably-priced provision of gigabit-speed internet.

The purpose of signing this resolution is to present to these bidders a unified field of County residents, all of whom desire high-speed broadband to every home, school and business within this County. Currently, several cities are in the process of signing this resolution and several others have already signed. The Coachella Valley Association of Governments has provided the RIVCOconnect team with their own signed resolution, and so having WRCOG also sign the document of support would provide another layer of consensus and add an element of gravitas to the RFP.

Prior Action:

July 21, 2016: The Technical Advisory Committee received report.

Fiscal Impact:

This item is informational only; therefore, there is no fiscal impact.

Attachments:

1. WRCOG Resolution Number 02-17; A Resolution of the Executive Committee of the Western Riverside Council of Governments to Support Riverside County Information Technology's Broadband Initiative - RIVCOconnect.
2. CVAG's Resolution supporting the County's Broadband Fiber to the Premise Master Plan.

Item 4.D
RIVCOconnect Broadband Initiative

Attachment 1
WRCOG Resolution Number 02-17; A Resolution of the Executive Committee of the Western Riverside Council of Governments to Support Riverside County Information Technology's Broadband Initiative - RIVCOconnect

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RESOLUTION NUMBER 02-17

A RESOLUTION OF THE EXECUTIVE COMMITTEE OF THE WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS TO SUPPORT RIVERSIDE COUNTY INFORMATION TECNOLOGY'S BROADBAND INITIATIVE - RIVCOCONNECT

WHEREAS, all Riverside County residents, businesses, and institutions need high quality gigabit broadband services where they live, work, learn and play; and

WHEREAS, closing the digital divide is important and provides long-term community benefits that include the ability to fully engage in the digital economy, access existing and emerging services, and expands economic opportunities; and

WHEREAS, high speed broadband enables improved healthcare access, treatment and information; and

WHEREAS, high speed broadband enables new business models, creates business efficiencies, drives job creation, and connects goods and services to customers and partners worldwide; and

WHEREAS, high speed broadband enables changes in how we access educational resources, collaborate, conduct research and continue to learn anytime, anyplace and at any pace; and

WHEREAS, high speed broadband enables greater civic participation and brings communities together, helps improve public safety, and makes our transportation systems more resilient and efficient; and

WHEREAS, the Executive Committee and other community partners can work together to affect the deployment decisions of broadband providers by lowering the cost of entry and operation of systems in our communities, reduce the risks of delays during the planning, permitting and construction phases, provide opportunities for increasing revenue, and creating new avenues for competitive entry; and

WHEREAS, the Executive Committee supports the adoption of consistent expedited broadband permitting processes throughout participating jurisdictions; and

WHEREAS, the Executive Committee supports the concept of 'Dig Once' whereby conduit is installed for future or immediate use for fiber optic cable installation whenever underground construction occurs in a roadway; and

WHEREAS, the Executive Committee supports the aggregation of demand by all participating communities as anchor tenants of selected provider(s) if acceptable services are available.

NOW, THEREFORE, BE IT RESOLVED by Executive Committee of the Western Riverside Council of Governments follows:

The Executive Committee of WRCOG does herby support the Riverside County Broadband Master Plan and the development of a Request for Participation (RFP) for the deployment of gigabit fiber services to all homes, businesses and institutions countywide.

PASSED AND ADOPTED by the Executive Committee of the Western Riverside Council of Governments on February 6, 2017.

____
Ben Benoit, Chair
WRCOG Executive Committee

____
Rick Bishop, Secretary
WRCOG Executive Committee

Approved as to form:

____
Steven DeBaun
WRCOG Legal Counsel

AYES: _______ NOES: _______ ABSENT: _______ ABSTAIN: _______

Item 4.D

RIVCOconnect Broadband Initiative

Attachment 2

CVAG's Resolution supporting the County's Broadband Fiber to the Premise Master Plan

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RESOLUTION NO. 16-006 SETTING FORTH COACHELLA VALLEY ASSOCIATION OF GOVERNMENT'S SUPPORT FOR RIVERSIDE COUNTY'S BROADBAND FIBER TO THE PREMISE MASTER PLAN

WHEREAS, all Riverside County residents, businesses and institutions need high quality gigabit broadband services where they live, work, learn and play; and
WHEREAS, closing the digital divide is important and provides long-term community benefits that include the ability to fully engage in the digital economy, access existing and emerging services, and expands economic opportunities; and
WHEREAS, high speed broadband enables improved healthcare access, treatment and information; and
WHEREAS, high speed broadband enables new business models, creates business efficiencies, drives job creation, and connects goods and services to customers and partners worldwide; and
WHEREAS, high speed broadband enables changes in how we access educational resources, collaborate, conduct research and continue to learn anytime, anyplace and at any pace; and
WHEREAS, high speed broadband enables greater civic participation and brings communities together, helps improve public safety, and makes our transportation systems more resilient and efficient; and
WHEREAS, the Coachella Valley Association of Governments and other community partners can work together to affect the deployment decisions of broadband providers by lowering the cost of entry and operation of systems in our communities, reduce the risks of delays during the planning, permitting and construction phases, provide opportunities for increasing revenue, and creating new avenues for competitive entry; and
WHEREAS, the Coachella Valley Association of Governments supports the adoption of consistent expedited broadband permitting processes throughout participating jurisdictions; and
WHEREAS, the Coachella Valley Association of Governments supports the concept of 'Dig Once' whereby conduit is installed for future or immediate use for fiber optic cable installation whenever underground construction occurs in a roadway; and
WHEREAS, the Coachella Valley Association of Governments supports the aggregation of demand by all participating communities as anchor tenants of selected provider(s) if acceptable services are available.
NOW, THEREFORE, BE IT RESOLVED on this 5th day of December 2016 that the Coachella Valley Association of Governments does herby support the Riverside County Broadband Master Plan and the development of a Request for Participation (RFP) for the deployment of gigabit fiber services to all homes, businesses and institutions countywide.

CVAG Executive Committee Chair
Dana Reed

Executive Director
Tom Kirk

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Item 4.E

Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: Finance Department Activities Update

Contact: Ernie Reyna, Chief Financial Officer, reyna@wrcog.cog.ca.us, (951) 955-8432

Date: February 6, 2017

***The purpose of this item is to** provide an update on the interim WRCOG audit of Fiscal Year 2015/2016, which should result in a final Comprehensive Annual Financial Report (CAFR) issued in January 2017. This report also provides an update on agency budget amendments, and an update on the annual TUMF Audit for 2015/2016.*

Requested Action:

1. Receive and file.

Financial Audit

Financial auditors from Vavrinek, Trine, Day, & Co., conducted their interim audit work for Fiscal Year (FY) 2015/2016 at the end of July 2016. The auditors worked with WRCOG staff to begin the process of reviewing the financial ledgers, and returned during the week of September 26, 2016, to conduct final fieldwork. At the Finance Directors' Committee on January 26, 2017, an update on the audit and financial statements was presented. The year-end financials have been issued and the audit concluded along with the final CAFR issued on January 31, 2017.

Budget Amendment

December 31, 2016, marked the end of the second quarter of FY 2016/2017, and the Administration & Finance Committee was presented with a budget amendment at its January 11, 2017, meeting. The Technical Advisory Committee also considered the amendment report at its January 19, 2017, meeting. The Executive Committee will consider the amendment report at its February 6, 2017, meeting under a separate item

Annual TUMF Audit for FY 2015/2016

Staff has completed the TUMF audits of each jurisdiction and the final reports will be issued in February of 2017. The TUMF audits allow staff to ensure that member agencies are correctly calculating and remitting TUMF funds in compliance with the TUMF Program.

Prior Actions:

January 19, 2017: The Technical Advisory Committee received report.
January 11, 2017: The Administration & Finance Committee received report.

Fiscal Impact:

This item is informational only; therefore, there is no fiscal impact.

Attachment:

None.

Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **Financial Report Summary through November 2016**

Contact: **Ernie Reyna, Chief Financial Officer, reyna@wrcog.cog.ca.us, (951) 955-8432**

Date: **February 6, 2017**

The purpose of this item is to *provide a monthly summary of WRCOG's financial statements in the form of combined Agency revenues and costs.*

Requested Action:

1. Receive and file.

Attached for Committee review is the Financial Report Summary through November 2016.

Prior Actions:

January 19, 2017: The Technical Advisory Committee received report.
January 11, 2017: The Administration & Finance Committee received report.

Fiscal Impact:

This item is informational only; therefore there is no fiscal impact.

Attachment:

1. Financial Report Summary – November 2016.

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Item 4.F

Financial Report Summary through November 2016

Attachment 1

Financial Report Summary – November 2016

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Western Riverside Council of Governments
Monthly Budget to Actuals
For the Month Ending November 30, 2016

		Approved 6/30/2017 Budget	Thru 11/30/2016 Actual	Remaining 6/30/2017 Budget
	Revenues			
40001	Member Dues	309,410	306,410	3,000
42001	Other Revenue	-	15	(15)
42004	General Assembly	300,000	5,000	295,000
40601	WRCOG HERO	1,963,735	565,983	1,397,752
40602	SCE Phase II	57,000		57,000
40604	CA HERO	7,615,461	2,766,363	4,849,098
40605	The Gas Company Partnership	62,000	16,944	45,056
40606	SCE WRELP	-	4,692	(4,692)
40607	WRCOG HERO Commercial	27,500	11,384	16,116
40609	SCE Phase III	-	10,634	(10,634)
40611	WRCOG HERO Recording Revenue	335,555	132,125	203,430
40612	CA HERO Recording Revenue	1,301,300	590,290	711,010
40614	Active Transportation	200,000	50,254	149,746
41201	Solid Waste	107,915	93,415	14,500
41401	Used Oil Opportunity Grants	250,000	264,320	(14,320)
41402	Air Quality-Clean Cities	139,500	128,000	11,500
41701	LTF	692,000	701,250	(9,250)
43001	Commercial/Service - Admin (4%)	37,074	30,846	6,229
43002	Retail - Admin (4%)	142,224	51,431	90,793
43003	Industrial - Admin 4%)	128,446	47,587	80,860
43004	Residential/Multi/Single - Admin (4%)	1,067,271	334,459	732,813
43005	Multi-Family - Admin (4%)	224,983	21,185	203,798
43001	Commercial/Service	889,786	740,581	149,205
43002	Retail	3,413,375	1,234,334	2,179,040
43003	Industrial	3,082,710	1,142,077	1,940,632
43004	Residential/Multi/Single	25,614,514	8,026,729	17,587,785
43005	Multi-Family	5,399,595	508,450	4,891,146
	Total Revenues	**61,125,676**	**17,784,757**	**43,340,919**
	Expenditures			
	Wages and Benefits			
60001	Wages & Salaries	1,981,159	885,417	1,095,742
61000	Fringe Benefits	579,477	300,166	279,311
	Total Wages and Benefits	**2,620,636**	**1,185,583**	**1,435,053**
	General Operations			
63000	Overhead Allocation	1,518,136	632,557	885,579
65101	General Legal Services	410,673	324,715	85,958
65401	Audit Fees	25,000	10,300	14,700
65505	Bank Fees	25,500	7,904	17,596
65507	Commissioners Per Diem	46,500	21,150	25,350
73001	Office Lease	145,000	56,514	88,486
73003	WRCOG Auto Fuels Expense	178	299	(121)
73004	WRCOG Auto Maint Expense	16	33	(17)
73102	Parking Validations	3,650	2,835	815
73104	Staff Recognition	1,200	632	568
73107	Event Support	181,888	30,377	151,511
73108	General Supplies	20,833	6,866	13,967
73109	Computer Supplies	7,925	3,336	4,589
73110	Computer Software	13,705	10,638	3,067
73111	Rent/Lease Equipment	25,000	15,525	9,475
73113	Membership Dues	40,600	7,815	32,785
73114	Subcriptions/Publications	8,283	5,102	3,181
73115	Meeting Support/Services	14,098	3,650	10,448
73116	Postage	5,653	1,400	4,253
73117	Other Household Expenditures	2,354	2,630	(276)
73118	COG Partnership Agreement	40,000	10,254	29,746
73122	Computer Hardware	4,000	337	3,663
73201	Communications-Regular	2,000	350	1,650
73203	Communications-Long Distance	1,200	95	1,105
73204	Communications-Cellular	11,186	4,476	6,710
73206	Communications-Comp Sv	17,000	30,414	(13,414)
73209	Communications-Web Site	15,600	407	15,193
73301	Equipment Maintenance - General	7,070	2,724	4,346
73302	Equipment Maintenance - Computers	3,267	11,418	(8,151)
73405	Insurance - General/Business Liason	63,520	73,020	(9,500)
73407	WRCOG Auto Insurance	345	345	-
73502	County RCIT	2,500	545	1,955
73506	CA HERO Recording Fee	1,636,855	474,368	1,162,487
73601	Seminars/Conferences	25,013	6,692	18,322
73605	General Assembly	300,000	1,723	298,277
73611	Travel - Mileage Reimbursement	21,252	6,038	15,214
73612	Travel - Ground Transportation	8,779	1,684	7,095
73613	Travel - Airfare	22,000	6,192	15,808
73620	Lodging	19,550	5,347	14,203
73630	Meals	10,091	4,130	5,961
73640	Other Incidentals	14,164	4,786	9,378
73650	Training	14,200	40	14,160
73703	Supplies/Materials	45,700	300	45,400
73706	Radio & TV Ads	44,853	25,750	19,103
XXXXX	TUMF Projects	38,399,980	15,297,485	23,102,495
85101	Consulting Labor	3,528,328	819,826	2,708,502
85102	Consulting Expenses	245,000	2,889	242,111
85180	BEYOND Expenditures	2,023,000	128,321	1,894,679
90101	Computer Equipment/Software	31,500	9,437	22,063
	Total General Operations	**49,225,890**	**17,441,113**	**31,152,220**
	Total Expenditures	**51,846,526**	**18,626,696**	**32,587,273**

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Item 4.G

Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **Regional Streetlight Program Activities Update**

Contact: **Tyler Masters, Program Manager, masters@wrcog.cog.ca.us, (951) 955-8378**

Date: **February 6, 2017**

The purpose of this item is to *provide the Committee with an update on the Streetlight City Council Presentations and the next steps that member jurisdictions are taking as they consider participating in the Program.*

Requested Action:

1. Receive and file.

WRCOG's Regional Streetlight Program will assist member jurisdictions with the acquisition and retrofit of their Southern California Edison (SCE)-owned and operated streetlights. The Program has three phases, which include: 1) streetlight inventory; 2) procurement and retrofitting of streetlights; and 3) ongoing operations and maintenance. The overall goal of the Program is to provide significant cost savings to the member jurisdictions.

Background

At the direction of the Executive Committee, WRCOG is developing a Regional Streetlight Program that will allow jurisdictions (and Community Service Districts) to purchase the streetlights within their boundaries that are currently owned / operated by SCE. Once the streetlights are owned by the member jurisdiction, the lamps will then be retrofitted to Light Emitting Diode (LED) technology to provide more economical operations (i.e., lower maintenance costs, reduced energy use, and improvements in public safety). Local control of the streetlight system allows jurisdictions opportunities to enable future revenue generating opportunities such as digital-ready networks, and telecommunications and IT strategies.

The goal of the Program is to provide cost-efficiencies for local jurisdictions through the purchase, retrofit, and maintain the streetlights within jurisdictional boundaries, without the need of additional jurisdictional resources. As a regional Program, WRCOG is working with jurisdictions to move through the acquisition process, develop financing recommendations, develop / update regional and community-specific streetlight standards, and implement a regional operations and maintenance agreement that will increase the level of service currently being provided by SCE.

City Council Presentations

To support the education of the Regional Streetlight Program staff has provided a number of presentations including City Council Study Sessions, Council Members briefings, and City Commissions, in addition to over 25 WRCOG Committee update presentations and City-specific cash flow meetings. Staff is working with member staff to set additional presentations and/or meetings as requested.

Next Steps: WRCOG staff has been working with participating member jurisdictions and SCE to support jurisdictions through the acquisition processes to transition current SCE-owned streetlights to jurisdictional ownership. After assessing feasibility of acquiring its streetlights from SCE, one of the next major steps in order to complete the acquisition process is for each interested jurisdiction and SCE to mutually agree on a Purchase and Sales Agreement. The Sales Agreement would then need to be taken to City Council for approval. Several WRCOG cities have scheduled City Council meetings to consider approval of their Sales Agreement:

January 24, 2017: City of Lake Elsinore - City Council decision
February 7, 2017: City of San Jacinto - City Council presentation and potential decision
February 14, 2017: City of Hemet - Council Study Session followed by potential February decision
February 15, 2017: City of Menifee - Anticipated City Council decision
February/March 2017: City of Murrieta - Anticipated City Council decision
February 2017: City of Temecula - Anticipated City Council decision
February 2017: City of Wildomar - Anticipated City Council decision

On January 24, 2017, the City of Lake Elsinore City Council unanimously approved the following actions:

1. Approved the Purchase and Sale Agreement, including the No-Fee Light Pole License Agreement, substantially as to form, with SCE to acquire approximately 3,186 sellable streetlights, and authorized the City Manager to execute the required documents subject to City Attorney's final approval.

2. Approved and Authorized the City Manager to execute the necessary documents with Bank of America Public Capital Corporation ("BofA") to provide financing for the acquisition and retrofit of streetlights to LED technology. The BofA option provides a "direct placement lease" which is secured by the streetlights.

3. Directed City staff to complete the following items:

   a. Determine new Street Light Standards
   b. Determine LED retro-fitting options to reduce energy consumption
   c. Determine the Operation and Maintenance (O&M) responsibilities

Upon jurisdiction approval of the Sales Agreement, SCE will then submit the Sales Agreement to the California Public Utilities Commission (CPUC) for final approval before the transfer of streetlights can occur. Dependent upon the monetary size indicated in the Sales Agreement, the CPUC could take anywhere between two to six months to approve.

Below are the next steps that will be taken by a WRCOG member jurisdiction during 2017:

Jurisdiction	Received SCE evaluation	SCE Sales Distributed	Council Action on SCE Sales Contract	Selecting financing options	Anticipated CPUC application	Anticipated CPUC approval	Anticipated Retrofit
Calimesa	12/15/15	10/19/16	TBD	TBD	TBD	TBD	TBD
Corona	No	The City already owns most of the streetlights within its City Boundaries					
Eastvale	12/15/15	10/19/16	TBD	TBD	TBD	TBD	TBD
Hemet	1/20/16	10/19/16	Feb. 2017	TBD	May 2017	Aug. 2017	Sept. 2017
Jurupa Valley	2/26/16	10/19/16	TBD	TBD	TBD	TBD	TBD
Lake Elsinore	9/28/15	10/19/16	1/24/17	TBD	April 2017	July 2017	Aug. 2017

Menifee	1/8/16	10/19/16	2/1/17	TBD	May 2017	Aug. 2017	Sept. 2017
Murrieta	10/23/15	10/19/16	Feb. 2017	TBD	May 2017	Nov. 2017	Dec. 2017
Norco	3/14/16	10/19/16	TBD	TBD	TBD	TBD	TBD
Perris	1/19/16	10/19/16	TBD	TBD	TBD	TBD	TBD
San Jacinto	1/21/16	10/19/16	2/7/17	TBD	May 2017	Aug. 2017	Sept. 2017
Temecula	9/28/16	10/19/16	Feb. 2017	TBD	May 2017	Nov. 2017	Dec. 2017
Wildomar	1/19/16	10/19/16	Feb. 2017	TBD	May 2017	Aug. 2017	Sept. 2017
County of Riverside	3/16/16	10/19/16	TBD	TBD	TBD	TBD	TBD
JCSD	12/15/16	10/19/16	TBD	TBD	TBD	TBD	TBD
RCSD	2/26/16	RCSD will support the City of Jurupa Valley if the City chooses to participate in the Regional Program					

WRCOG staff continues to schedule meetings with the remaining member cities to work with SCE on the finalization of the Sales Agreement and assist WRCOG member cities at City Council meetings for decision on the Sales Agreement. If interested in discussing where your jurisdiction is in the process and what the next steps are, please contact Tyler Masters, Program Manager, at (951) 955-8378 or masters@wrcog.cog.ca.us.

Demonstration Area Tour Update: In Partnership with the City of Hemet, WRCOG has installed a variety of LED streetlights from different vendors in five Demonstration Areas throughout the City. These five Demonstration Areas represent different street and land use types, from school, residential, and commercial areas, to low, medium, and high traffic street areas. 12 outdoor lighting manufacturers are participating in these Demonstration Areas.

Input from local government officials, public safety staff, health experts, residents, business owners, and other community stakeholders is important before moving forward with a plan to upgrade streetlights in the subregion. With support from RTA, WRCOG was able to provide guided educational bus tours of the five Demonstration Areas for participants:

- November 10, 2016, at 5:30 p.m.
- November 14, 2016, at 5:30 p.m.
- November 29, 2016, at 5:30 p.m.
- December 7, 2016, at 5:30 p.m.
- January 30, 2016, at 5:30 p.m.

Prior Actions:

January 19, 2017: The Technical Advisory Committee received report.
January 12, 2017: The Public Works Committee received report.

Fiscal Impact:

Activities for the Regional Streetlight Program are included in the Agency's adopted Fiscal Year 2016/2017 Budget. The additional costs associated with this contract amendment in the amount of $70,779 will be reflected in an upcoming Agency Budget Amendment.

Attachment:

None.

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Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **Western Riverside Energy Leader Partnership Update**

Contact: **Tyler Masters, Program Manager, masters@wrcog.cog.ca.us, (951) 955-8378**

Date: **February 6, 2017**

The purpose of this item is to *provide the Committee with an update the January WRELP Zone meeting and the addition of the Cities of Corona and Moreno Valley into the Western Riverside Energy Leader Partnership.*

Requested Action:

1. Receive and file.

The Western Riverside Energy Leader Partnership (WRELP) responds to Executive Committee direction for WRCOG, Southern California Edison (SCE), and the Southern California Gas Company (SoCal Gas) to seek ways to improve marketing and outreach to the WRCOG subregion regarding energy efficiency. WRELP is designed to assist local governments to set an example for their communities to increase energy efficiency, reduce greenhouse gas (GHG) emissions, increase renewable energy usage, and improve air quality.

January WRELP meeting

On January 26, 2017, WRCOG hosted a WRELP meeting to discuss various items of importance to all member jurisdictions. This meeting was held at the City of Hemet Public Library (300 E Latham Ave., Hemet) from 10:00 a.m. – 11:30 a.m.

At the previous WRELP Quarterly meeting, members decided to conduct zone-type monthly meetings. The purpose of hosting these monthly zone meetings is to visit the participating WRELP member jurisdictions in order to understand what energy efficiency projects participating cities are interested in implementing at their municipal facilities, as well as to provide updates on the types of assistance that WRELP staff, SCE, and/or SoCal Gas can provide. WRELP staff will be visiting member cities on a monthly basis to learn about potential projects and jurisdiction goals related to energy efficiency. These smaller group settings will allow individual jurisdictions to talk specifically about their cities' projects, and identify and request project-specific support and resources from WRCOG and Utility staff.

Cities of Corona and Moreno Valley to Join WRELP

In January 2017, the Cities of Corona and Moreno Valley began transitioning to WRELP. Both Cities have been members of the Community Energy Partnership (CEP), which supports energy efficiency projects at municipal facilities and engages within the community to promote the idea of energy efficiency. The City of Corona joined the CEP in 2004 and the City of Moreno Valley joined the CEP in 2002, before WRELP was developed. On January 18, 2017, the City of Corona adopted a Resolution to officially join WRELP. The City of Moreno Valley will take an action to adopt a similar resolution in the next few months.

The reason for the transition for both Cities from the CEP to WRELP is that the California Public Utilities Commission (CPUC) has requested that Local Government Partnerships take on a more regional structure with the purpose of connecting cities with similar climate zones and needs, as well as to promote cost effectiveness. As such, the Cities of Corona and Moreno Valley will be transitioning from the CEP to the WRELP, which is administered by WRCOG.

The Cities of Corona and Moreno Valley are leaders in the field of energy efficiency. Through their participation in the CEP, between 2006 and 2016, both Cities have achieved a combined 8,942,900 kWh in energy savings.

Prior Action:

January 19, 2017: The Technical Advisory Committee received report.

Fiscal Impact:

This item is informational only; therefore, there is no fiscal impact.

Attachment:

None.

Item 4.I

Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **Environmental Department Activities Update**

Contact: **Dolores Sanchez Badillo, Staff Analyst, badillo@wrcog.cog.ca.us, (951) 955-8306**

Date: **February 6, 2017**

***The purpose of this item is to** provide an update on the Used Oil and Filter Exchange events and the progress of WRCOG's Pilot Litter Program being conducted in the City of Lake Elsinore.*

Requested Action:

1. Receive and file.

WRCOG assists its member jurisdictions with addressing state mandates, specifically the Integrated Waste Management Act (AB 939, Chapter 1095, Statutes of 1989), which required 25% and 50% diversion of waste from landfills by 1995 and 2000, respectively. While certain aspects of AB 939 have been modified over the years with legislation defining what materials counted towards diversion and how to calculate the diversion rate for jurisdictions, the intent of the bill remains. Each year, a jurisdiction must file an Electronic Annual Report (EAR) with CalRecycle on the jurisdictions' achievements in meeting and maintaining the diversion requirements. The Environmental Department also has a Regional Used Oil component which is designed to assist member jurisdictions in educating and promoting proper recycling and disposal of used oil, oil filters, and household hazardous waste (HHW) to the community.

Recycling Program Activities Update

In January 2017, WRCOG hosted three used oil events in Western Riverside County cities.

Used Oil Events: WRCOG's Used Oil and Oil Filter Exchange events help educate and facilitate the proper recycling of used motor oil and used oil filters in various WRCOG jurisdictions. The primary objective of hosting the events is to educate "Do It Yourself" (DIY) individuals who change their own oil, promoting the recycling of used oil and oil filters; therefore, an auto parts store is a great venue for educating these individuals. In addition to promoting used oil / oil filter recycling, staff informs the DIYer about the County-wide HHW Collection Program in which residents can drop-off other automotive and household hazardous products for free.

WRCOG's first Used Oil event of the year was held in the City of Murrieta on January 7, 2017, and was visited by approximately 75 attendees. The WRCOG team was joined by representatives from radio station KGGI. The group engaged with Murrieta residents by discussing the basics of automobile oil changing and offered free materials to get the job done. Area residents who stopped by had questions on the locations of local HHW facilities. Staff had materials available on HHW, such as composting and disposal of common medical waste. Attendees, some who drove in from the Cities of Lake Elsinore and Temecula, were pleased with the used oil containers provided that morning. Those in attendance voiced appreciation of the event and asked for continued education for those who might not know the risks of **not** recycling. That morning, 72 used oil containers were distributed, and 21 used oil filters were exchanged.

WRCOG and KGGI Radio staff at the Used Oil event in Murrieta.

The City of Jurupa Valley partnered with WRCOG's Environmental Department on January 21, 2017, for the City's first Used Oil event of the year. Staff was on hand to spread awareness about the program to those who make oil changes at home. The team provided important information regarding automobile oil recycling, such as used oil filters, which typically contain 10% of the used product after oil changes. The public was advised to bring the used oil right back where they purchased it – in this case, O'Reilly's Auto Parts on Mission Blvd. The team spoke to nearly 30 customers about locations to take HHW such as paint, aerosol cans, batteries and e-waste. Attendees were very appreciative of the event. A number of residents had an interest in the information, especially on where to take HHW. Quite a few residents expressed their thanks for the valuable used oil materials, one saying the "kit" provided saved him a lot of money.

WRCOG Intern Jorge Nieto manages the Used Oil booth in Jurupa Valley.

On January 28, 2017, residents of the City of Lake Elsinore attended a Used Oil Event held at the AutoZone located on 32231 Mission Trail Blvd. DIYers exchanged their old oil filters for new ones. Many attendees stopped by the WRCOG booth to receive free oil drain containers, oil filter drain containers, shop rags, oil filter wrenches, and *The Complete Guide to Residential Recycling*. WRCOG distributed over 70 FREE oil drain containers. Staff coordinated with AutoZone management in advance to market the event to residents. Flyers, radio spots and Facebook notices helped get the word out. KATY Radio commercials were broadcasted a week prior to the event and station employees were on hand for a remote broadcast that morning. Free DIY oil materials were distributed to all who attended.

Upcoming Used Oil Events

The following is a list of Used Oil and Oil Filter Exchange events that are presently scheduled. To request an event for your jurisdiction please contact Jorge Nieto, WRCOG Intern, at (951) 955-8328 or nieto@wrcog.cog.ca.us.

Date	Event	Location	Time
2/4/17	City of Norco Used Oil Event	AutoZone, 1404 Hamner Ave.	9 a.m. – 12 p.m.
2/18/17	City of Riverside Used Oil Event	AutoZone, 7315 Indiana Ave.	9 a.m. – 1 p.m.
3/4/17	City of Moreno Valley Used Oil Event	AutoZone, 12601 Perris Blvd.	9 a.m. – 12 p.m.
3/11/17	City of Eastvale Used Oil Event	Autozone, 14228 Schleisman Rd.	9 a.m. – 12 p.m.
3/18/17	City of Corona Used Oil Event	AutoZone, 501 North McKinley	9 a.m. – 12 p.m.

CalRecycle Grant Opportunities

The following is a list of current grant opportunities offered by CalRecycle to assist public and private entities in the safe and effective management of the waste stream. WRCOG provides grant assistance to member jurisdictions seeking to pursue funding opportunities. To request grant assistance for the grants listed below, please contact Dolores Sanchez Badillo, Staff Analyst, at (951) 955-8306 or badillo@wrcog.cog.ca.us

Organics Grant Program (Fiscal Year 2016-2017): The Department of Resources Recycling and Recovery (CalRecycle) administers the Organics Grant Program pursuant to Public Resources Code section 42999. The purpose of this competitive grant Program is to reduce greenhouse gas emissions by expanding existing capacity or establishing new facilities in California to reduce the amount of California-generated green materials, food materials, or alternative daily cover being sent to landfills.

Funding: $24,000,000 is available for Fiscal Year 2016-2017, to be distributed as follows:

- Compost Projects: $12,000,000 allocation for compost projects with a maximum grant award of $3,000,000 per application. This includes $2,400,000 in requested infrastructure costs and $600,000 in performance payments.
- Rural Programs: $3,000,000 from the compost projects allocation is available for Rural Program applications. The maximum grant award is $3,000,000 per application. This includes $2,400,000 in requested infrastructure costs and $600,000 in performance payments.

There is a $12,000,000 allocation for a digestion project, with a maximum award of $4,000,000 per application. This includes $3,200,000 in requested infrastructure costs and $800,000 in performance payments. If interested, information can be found at:
http://www.calrecycle.ca.gov/Climate/GrantsLoans/Organics/FY201617/default.htm

Application due date: March 9, 2017

WRCOG Pilot and Regional Litter Initiative

Lake Elsinore Pilot Litter Program Graphic Designs for Educational Outreach

A partnership comprised of the City of Lake Elsinore, WRCOG, and Riverside Flood Control and Water Conservation District is working hard to move the Lake Elsinore Litter Pilot Program to the next level. April 22, 2017, is both Earth Day and the day of the Annual Lake Elsinore Clean Extreme event. All parties are working together to merge the Litter Pilot Program into the successful community event. This year, over 700 city residents are expected to clean lots, pick up highway trash, and paint a large mural on a wall located directly across the highway from the Lake Elsinore Outlets.

The Lake Elsinore Litter Program will donate materials, conduct contests, bring along a remote radio station opportunity, and provide “Love Where You Live” information for all attendees. WRCOG would like to thank Lowe’s Home Improvement and CR&R Environmental Services for their contributions. Look for more information on the April 22, 2017, Clean Extreme Event on the City of Lake Elsinore’s and WRCOG websites.

Local businesses will also be involved in the “Love Where You Live” litter program to advocate having a clean and litter-free environment. Static cling “Litter-Free Zone” stickers will be provided and placed upon business store windows to help reduce litter as part of the No Littering Campaign. Approximately thirty businesses on Main Street will take the no-litter pledge, promising to combat litter and behaviors promoting it.

Lake Elsinore Litter Program Business Window Sticker

Various items such as recycle bins and informational flyers detailing important tips on keeping commercial businesses clean and litter-free will be provided to these stores.

Prior Action:

January 19, 2017: The Technical Advisory Committee received report.

Fiscal Impact:

Solid Waste and Used Oil Program activities are included in the current adopted Agency budget. Costs identified in association with the Pilot Litter Initiative will come from WRCOG carryover funds within the Environment Department and reflected in an upcoming Agency Budget for Fiscal Year 2016/2017, as a quarterly budget amendment, if needed.

Attachment:

None.

Item 4.J

Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **Clean Cities Coalition Activities Update**

Contact: **Christopher Gray, Director of Transportation, gray@wrcog.cog.ca.us, (951) 955-8304**

Date: **February 6, 2017**

The purpose of this item is to *provide an on-going briefing for the Clean Cities Coalition, an on-going Program to encourage the purchase and use of alternative fueled vehicles within the WRCOG subregion.*

Requested Action:

1. Receive and file.

AB 2766 Reporting Information

The AB 2766 budget allows for 10% to be allocated by jurisdictions to air quality education and outreach efforts. The Clean Cities Coalition conducts these efforts on behalf of the member agencies as educational and outreach programs designed to empower our stakeholders with the tools and resources necessary to develop and implement successful fuel diversification, prepare vehicle upgrade strategies based on specific operational needs and local market conditions, and diversify their programs to include the following:

- Promote the reduction of petroleum-based fuels and increase the use of alternative fuel vehicles, fuels, and advanced technologies;
- Promote diversification and vehicle upgrade strategies;
- Address AB 32 mandates to reduce greenhouse gas emissions; and
- Incorporate additional topics such as public health, active transportation planning, and energy efficiency strategies.

For the purposes of AB 2766, WRCOG has provided a summary of accomplishments for Fiscal Year 2015-2016 to each member agency – a letter to the City of Banning is provided for reference. A short summary of the accomplishments are provided below.

- Establish Partnership with UC Riverside's Center for Environmental Research and Technology (CE-CERT): Staff has identified CE-CERT to be a vital partner for the advancement of the goals of the Clean Cities Coalition. The research and development conducted locally at the CE-CERT is a tremendous benefit to the subregion and staff aims to establish a partnership to enable access and frequent updates to the Coalition members.

- The Western Riverside County Active Transportation Plan: Staff has been working with local jurisdiction staff to ensure a regionally significant active transportation plan is crafted, so that any form of active transportation can be viable option for residents to utilize and reduce greenhouse gas emissions.

- County of Riverside Purchasing and Fleet Services Vehicle Vendor Expo – June 2, 2016: Local policy makers, fleet operators, and industry representative from the region joined a day-long exhibit and panels to support alternative fuel purchasing and fleets. One of the panels featured WRCOG, in which staff discussed funding programs to support alternative fuel deployments in Southern California fleets.

- South Coast Air Quality Management District's (AQMD) 2016 Air Quality Management Plan (AQMP) Outreach: AQMD provided an overview and led discussions with Coalition members at a stakeholder meeting in October to review the 2016 AQMP. WRCOG staff reviewed the 2016 AQMP and provided feedback to AQMD staff.

- Clean Cities Coalition Stakeholder Meetings: Staff hosted several meetings to discuss air quality legislation, funding opportunities, and clean technologies associated with air quality.

- News and Publications: Staff continues to produce quarterly newsletters, Public Service Announcements and publications regarding alternative fuel / advanced technology advancements and interviews with air quality champions.

- Update of Good Neighbor Guidelines for Siting New and/or Modified Warehouse / Distribution Facilities: WRCOG conducted an effort to update these guidelines in the summer of 2016. This update included three key elements: 1) Identifying strategies used by other agencies to address similar issues; 2) Updating references to any technical documents in the guidelines; and 3) Reviewing the guidelines to update as appropriate.

Outreach Events

Active Transportation Network: Staff participates in this quarterly meeting to discuss active transportation opportunities and challenges in the Riverside County area.

Safe Routes to School: Staff participates with the Riverside County Department of Public Health to encourage students to walk or ride their bikes to school.

Grant Writing Services

AQMD Elective Vehicle Charging Equipment Rebates: Staff was available to assist with the application process for funding made available through AQMD via EPA funds for government and non-profits agencies to purchase additional EV chargers.

Additional Workshops & Activities

Mobile Source Air Pollution Reduction Review Committee (MSRC) Work Program Development Workshops: A series of workshops were held in order to receive input on MSRC's two-year Work Program, which distributes approximately $14 million each year to projects designed to reduce emissions from motor vehicles within the South Coast Air District. Coalition members participated in a discussion about how the MSRC can help improve air quality in the South Coast region and assist AQMD in meeting its clean air requirements.

AQMD Air Quality Management Plan (AQMP) Advisory Committee Monthly Meetings: WRCOG staff attended monthly meetings of the AQMP Advisory Committee.

Prior Action:

January 19, 2017: The Technical Advisory Committee received report.

Fiscal Impact:

This item is informational only; therefore there is no fiscal impact.

Attachment:

1. AB 2766 Report FY 2015-2016.

Item 4.J

Clean Cities Coalition Activities Update

Attachment 1

AB 2766 Report FY 2015-2016

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BANNING INTEROFFICE MEMO

Date: January 27, 2017

To: Art Vela, Public Works Director, City of Banning

From: Christopher Gray, Director of Transportation, WRCOG

Subject: City of Banning AB 2766 Reporting Information ($3,000 for the Clean Cities Coalition)

Who we are: The Western Riverside County Clean Cities Coalition (Coalition) is a voluntary program that brings together local government and private industry in an effort to expand the use of alternatives to gasoline and diesel fuel.

Coalition goals: The AB 2766 budget allows for 10% to be allocated to air quality education and outreach efforts. The Coalition educational and outreach programs are designed to empower our stakeholders with the tools and resources necessary to develop and implement successful fuel diversification, vehicle upgrade strategies based on specific operational needs and local market conditions, and diversify their programs to include the following:

- Promote the reduction of petroleum based fuels and increase the use of alternative fuel vehicles, fuels, and advanced technologies;
- Promote diversification and vehicle upgrade strategies;
- Address AB 32 mandates to reduce greenhouse gas emissions; and
- Incorporate additional topics such as public health, active transportation planning, and energy efficiency strategies.

In addition, the Coalition coordinates air quality efforts for both private and public sectors by providing a forum to discover commonalities, combine resources, and promote the benefits of alternative fuels and advanced technology vehicles in their communities. The Coalition looked to provide this forum by beginning to form a relationship with the University of California, Riverside's Center for Environmental Research and Technology, as noted in the accomplishments.

Where our funding comes from: The Coalition receives funding from the U.S. Department of Energy, private sector sponsorships, and its member jurisdictions: the Cities of Banning, Calimesa, Corona, Eastvale, Lake Elsinore, Hemet, Moreno Valley, Perris, Riverside, San Jacinto, Temecula, and the County of Riverside. **A portion of the City's AB 2766 funding is used to implement the Coalition, and the City is notified about all program activities.**

How we are organized: This program is administered by the Western Riverside Council of Governments.

AB 2766 Funds: The AB 2766 funds are utilized for staff funding to manage and administer the following programs:

Selected FY 2015/2016 accomplishments:

- Establish Partnership with UC Riverside's Center for Environmental Research and Technology (CE-CERT) – Coalition staff has identified CE-CERT to be a vital partner for the advancement of the goals of the Clean Cities Coalition. The research and development conducted locally at the CE-CERT is a tremendous benefit to the subregion and the Coalition staff aims to establish a partnership to enable access and frequent updates to the Coalition members.

  CE-CERT is the largest research center on campus and brings together multiple disciplines throughout the campus to address environmental challenges in air, energy, and transportation. The Center's research focus is on utilizing technology to achieve environmental sustainability that requires innovation in many different areas. Among the topics CE-CERT researches that are most relevant, and the Coalition will be looking for more information on in the future, are emissions and fuel research – encompassing measurement of vehicle emissions in the laboratory and in the field, under controlled and “real world” operating conditions; and CE-CERT’s Sustainable Integrated Grid Initiative – research to integrate solar electricity generation, smart distribution, commercial-scale energy storage, and electric transportation.

- <u>The Western Riverside County Active Transportation Plan</u>: In November 2014, WRCOG was awarded funds from the California Transportation Commission to create the Western Riverside County Active Transportation Plan. Work has commenced on the Plan and is working to address the walking and biking infrastructure in Western Riverside County, as well as increasing safety for pedestrians and cyclists. Coalition staff has been working with local jurisdiction staff to ensure a regionally significant active transportation plan is crafted, so that any form of active transportation can be viable option for residents to utilize and reduce greenhouse gas emissions.

- <u>County of Riverside Purchasing and Fleet Services Vehicle Vendor Expo – June 2, 2016:</u> local policy makers, fleet operators and industry representative from the region joined a day-long exhibit and panels to support alternative fuel purchasing and fleets. One of the panels featured Coalition staff to discuss funding programs to support alternative fuel deployments in Southern California fleets. Another panel featured experience fleet managers sharing information on alternative fuel deployment efforts and provided lessons learned. The main event was focused around exhibition booths and displays from fleet operators, industry, and government agencies.

- <u>South Coast Air Quality Management District’s (AQMD) 2016 Air Quality Management Plan (AQMP) Outreach:</u> AQMD provided an overview and led discussions with Coalition members at a stakeholder meeting in October to review the 2016 AQMP. Coalition members actively participated and all questions raised were answered by AQMD staff. Also, Coalition staff reviewed the 2016 AQMP and provided feedback to AQMD staff.

- <u>Clean Cities Coalition Stakeholder Meetings</u>: The Coalition hosted several meetings to discuss air quality legislation, funding opportunities, and clean technologies associated with air quality.

- <u>News and Publications</u>: The Coalition continues to produce quarterly newsletters, Public Service Announcements (PSA), and publications regarding alternative fuel/advanced technology advancements and interviews with air quality champions.
    - City residents, businesses, elected officials, and County staff receives the quarterly newsletter as a web blast.

- <u>Update of Good Neighbor Guidelines for Siting New and/or Modified Warehouse / Distribution Facilities:</u> WRCOG adopted a Good Neighbor Guidelines for Siting New and/or Modified Warehouse / Distribution Facilities to guide local jurisdictions in siting and to try to integrate the new / modified facility well with its surroundings previously in 2003. The original purpose of these Guidelines were to assist developers, property owners, elected officials, community organizations, and the general public in addressing some of the complicated choices associated with siting warehouse / distribution facilities and understanding the options available when addressing environmental issues.

  WRCOG conducted an effort to update these guidelines in the Summer of 2016. This update included three key elements:

    - Identifying strategies used by other agencies to address similar issues
    - Updating references to any technical documents in the guidelines
    - Reviewing the guidelines to update them as appropriate

Outreach Events:

- Active Transportation Network: The Coalition participates in this quarterly meeting to discuss active transportation opportunities and challenges in the Riverside County area. This meeting provides updates on relevant events particular to the area, upcoming legislation, education events for bicycle/pedestrian safety, and opportunities to decrease vehicle dependency utilizing active transportation.

- Safe Routes to School: The Coalition participates with the Riverside County Department of Public Health to encourage students to walk or ride their bikes to school. This program reduces the vehicle miles traveled by parents and reduces greenhouse gas emissions. Coalition staff participated in Safe Routes to School meetings.

Grant Writing Services:

- The South Coast Air Quality Management District Elective Vehicle Charging Equipment Rebates: funding was made available through AQMD via EPA funds for government and non-profits agencies to purchase additional EV chargers. The amount of the rebate was up to $7,500 per charger, an additional $5,000 for solar panels associated with plug-in electric vehicles, and grant funds were limited to no more than $42,000 per site. Coalition staff was available to assist with the application process.

Additional Workshops & Activities:

- Mobile Source Air Pollution Reduction Review Committee (MSRC) Work Program Development Workshops: The Mobile Source Air Pollution Reduction Review Committee (MSRC) held a series of workshops to receive input on its two-year work program, which distributes approximately $14 million each year to projects designed to reduce emissions from motor vehicles on the South Coast Air District. Coalition members participated in a discussion about how the MSRC can help improve air quality in the South Coast region and assist SCAQMD in meeting its clean air requirements. The discussion also included a dialogue among stakeholders about their clean air priorities and how the MSRC could assist by considering funding for programs to meet their goals.

- South Coast Air Quality Management District (AQMD) Air Quality Management Plan (AQMP) Advisory Committee Monthly Meetings: WRCOG staff attended monthly meetings of the AQMP Advisory Committee. The AQMP is a regional and multi-agency effort (AQMD, California Air Resources Board, Southern California Association of Governments, and the U.S. Environmental Protection Agency). State and Federal planning requirements include developing control strategies, attainment demonstrations, reasonable further progress, and maintenance plans.

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Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **Single Signature Authority Report**

Contact: **Ernie Reyna, Chief Financial Officer, reyna@wrcog.cog.ca.us, (951) 955-8432**

Date: **February 6, 2017**

***The purpose of this item is to** notify the Committee of any recent contracts signed under the single-signature authority of the Executive Director.*

Requested Action:

1. Receive and file.

The Executive Director has single-signature authority for contracts up to $50,000. For the period of October 1, 2016, through December 31, 2016, there was one contract signed by the Executive Director.

The one contract signed by the Executive Director is for NetFile, Inc. NetFile is an online platform for filing the required Statement of Economic Interest Form 700. This platform will be used both by WRCOG and RCHCA. The total amount of this contract is $5,200 and will be paid in four quarterly installments of $1,300.

Prior Actions:

January 19, 2017: The Technical Advisory Committee received report for the period October 1, 2016, through December 31, 2016.

January 11, 2017: The Administration & Finance Committee received report for the period October 1, 2016, through December 31, 2016.

Fiscal Impact:

The $5,200 will be added to the General Fund's budget as an upcoming quarterly budget amendment to Fiscal Year 2016/2017.

Attachment:

1. Contracts Activity Spreadsheet.

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Item 4.K
Single Signature Authority Report

Attachment 1
Contracts Activity Spreadsheet

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Western Riverside Council of Governments
Contracts Activity Report
For the Period October 1, 2016, through December 31, 2016

Level Of Authority	Date	Consultant	Description of Services	Amount
Executive Director	11/29/2016	NetFile, Inc.	Online platform for filing Form 700	$5,200
Administration & Finance				
None				
Other				
None				
			Total Amount for Single Signature	**$ 5,200**

Prepared and Approved by

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Item 4.L

Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **Public Service Fellowship Program**

Contact: **Jennifer Ward, Director of Government Relations, ward@wrcog.cog.ca.us, (951) 955-0186**

Date: **February 6, 2017**

The purpose of this item is *to make Committee members aware of the second round of WRCOG's Public Service Fellowship, conducted in partnership with University of California, Riverside, and California Baptist University.*

Requested Action:

1. Receive and file.

In partnership with higher education institutions, WRCOG launched a Public Service Fellowship Program that provides local university graduates with career opportunities with local governments and agencies in a way that is mutually beneficial to both the Fellow and Agency.

Fellowship Program Overview

In early 2016, WRCOG launched a Public Service Fellowship Program in Western Riverside County, administered by WRCOG in partnership with University of California, Riverside (UCR) and California Baptist University (CBU). The Technical Advisory Committee (TAC) directed WRCOG staff to expand the Fellowship Program to include students from California State University, San Bernardino (CSUSB), and during the next several months staff will continue developing a relationship with the CSUSB Career Center in preparation to offer the Fellowship to those students in subsequent rounds. The goal of this Program is to retain local students in Western Riverside County to fulfill the subregion's needs for a robust public sector workforce and to combat the often-mentioned "brain drain" that Riverside County experiences when local students graduate but then leave the region to seek full-time employment elsewhere. The Fellowship Program targets students graduating from UCR and CBU, and engages them in career opportunities with local governments and agencies in a way that is mutually beneficial to both the Fellow and agency. The first round of Fellows began working within WRCOG's member agencies in July 2016 and will conclude their Fellowships in February or March 2017.

Fellowship Program Second Round

Based on the success of the Fellowship thus far as indicated by feedback from both the Fellows, university partners, and participating jurisdictions, WRCOG is proceeding with a second round of the Fellowship. The academic institutions will continue to provide high-caliber students that can contribute valuable assistance to agencies and ensure these students are prepared with the necessary skills, understanding, and education to succeed in the public sector. WRCOG's member agencies will again be able to draw from a "pre-screened" pool of qualified candidates that are likely to want to pursue a career in local government in Western Riverside County. WRCOG, UCR, and CBU will conduct a first round of interviews with the students who apply to the Fellowship to determine eligibility, and then the member agencies will have an opportunity to also interview potential candidates for their particular jurisdiction.

In order to facilitate the most successful Fellow placements, staff requested feedback from the Technical Advisory Committee through an Agency Interest Form. The information requested in the Agency Interest Form will provide valuable input to WRCOG, UCR, and CBU, and will aid in the process of recommending compatible Fellows for placement at the agencies.

Program Structure

WRCOG will continue operating the Fellowship by hiring the Fellows as temporary employees of WRCOG. WRCOG will also oversee the human resources and payroll aspects of the Program. Under this structure, Fellows can work up to 30 hours per week at their host Agency for a total of up to 960 hours per fiscal year. WRCOG staff are working with UCR and CBU to adhere to the following schedule for the second round of the Fellowship Program.

Timeline:

- January 2017: Collect feedback from WRCOG member agencies and finalize the pilot Program structure.
- February 2017: Notify students at UCR and CBU about the Fellowship and solicit interested applicants.
- March 2017: WRCOG, UCR, and CBU review applications, interview top candidates, and recommend agency placements.
- April 2017: Agencies interview and confirm Fellow placements. Fellows participate in Program orientation.
- May – July 2017: Fellowships begin.

Program Funding: WRCOG has allocated $400,000 in its Fiscal Year 2016/2017 Budget to initiate this Program. For this year, a small portion of funds will be allocated toward administration / operational costs, and the majority of funds will be allocated for compensation for the Fellows.

Prior Action:

January 19, 2017: The Technical Advisory Committee received report.

Fiscal Impact:

A total of $400,000 was allocated under the Agency Fiscal Year 2016/2017 Budget for the Public Service Fellowship Program, under the Government Relations budget.

Attachment:

None.

Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: Report from the League of California Cities

Contact: Erin Sasse, Regional Public Affairs Manager, League of California Cities, esasse@cacities.org, (951) 321-0771

Date: February 6, 2017

***The purpose of this item is to** inform the Committee of activities undertaken by the League of California Cities.*

Requested Action:

1. Receive and file.

AB 1 (Frazier) & SB 1 (Beall): Transportation Funding; League Postion: SUPPORT

Background: AB 1 (Frazier) and SB 1 (Beall) are similar proposals which will provide comprehensive and sensible transportation reforms, modest increases to existing revenue sources, and meaningful infrastructure investments. These proposals present an opportunity for the 2017 legislature to advance a broad framework to address the overwhelming accumulation of needed repairs and deferred maintenance in addition to other transportation needs.

The time is now to address the $73 billion unmet funding need for local streets and roads and the $72 billion backlog to the State's Highway System. The funding need will grow by an additional $20 billion in just ten years for local streets and roads alone.

California's leaders need to face the fact that the current transportation funding system is antiquated due to fuel efficiency advancements and a gas tax which was set in 1994 and has remained unadjusted.

AB 1 and SB 1 would raise revenue over a variety of sources:

- A 12 cent increase to the gas tax (SB 1 would ask to phase this increase in over 3 years);
- Ending the Board of Equalization's "true up" process on the unreliable price based excise tax on gas;
- A $38 increase to the vehicle registration fee;
- A $100 vehicle registration fee on zero emission vehicles;
- A 20 cent increase to the diesel excise tax;
- $300 million from existing cap and trade funds; and
- $500 million in vehicle weight fees phased in over five years.

Through these revenue sources, AB 1 and SB 1 would generate an additional $6 billion annually to provide desperately needed funding for the state and local transportation network. In addition to raising revenue, the proposal includes a series of reforms to improve efficiency, transparency, and accountability.

With the expressed commitment of Legislative Leadership and the Governor to finding a solution to our crumbling roads and an obsolete transportation funding stream, we urge this legislature to turn their immediate attention to both AB 1 and SB 1 as the vehicles to deliver this victory for California.

League Submits Comprehensive Comments on the Housing and Community Development's (HCD) Draft 2025 Statewide Housing Assessment

Public Workshops Planned; comments on Report Due by March 4, 2017.

The California Department of HCD recently released its Draft 2025 Housing Assessment: "California's Housing Future: Challenges and Opportunities."

HCD is asking stakeholders, including cities, to provide comments on the report that outlines what HCD has identified as the challenges to addressing housing affordability as well possible options to help increase housing supply and reduce overall housing costs. The League has submitted comprehensive comments that examine the report and identify areas where HCD's evaluation does not fully account for how market forces, other state policies, and lack of affordable housing resources affect housing development. Cities should also review the report and provide feedback to HCD.

Useful Information on Size and Scope of Problem: HCD's draft report contains information that helps describe the significant housing needs of California's diverse regions and residents, which includes:

- The assessment of the serious need for more affordable housing;
- The analysis of the economic impact of where housing is located;
- The understanding of the full range of housing needs in terms of rental and homeownership supply; and
- Using the lens of housing types, affordability and costs to project California's housing needs through 2025.

Disproportionate Focus on Role of Local Government and Incomplete Analysis of Market Forces and Lack of Affordable Housing Resources: The League's comments highlight some areas of concern, which include the following:

- The draft report disproportionately focuses on local government's role in the planning, zoning, and permitting process, but fails to examine or acknowledge the fundamental private market forces that contribute greatly to housing production or lack thereof.
- While some discussion of affordable housing resources is provided, surprisingly, the report makes no mention of how the elimination of redevelopment agencies in 2011 contributed to the loss of over $1 billion annually in affordable housing resources. Moreover, despite the scope of the described affordable housing crisis, the report conveys the Administration's opposition to any expenditure of additional state General Fund dollars on affordable housing.
- Concerns are also raised with several apparent conclusions presented in the report on the role of local government in the development of housing which lack sufficient supporting research and evidence.
- Inconsistent messaging. Some areas of the report state that a one-size-fits-all approach to housing does not work in California because of the State's diverse needs and markets. In other areas, however, the report advocates for top-down land use policies and changes that could affect all California cities.

The League's detailed comments are available on the League's website for cities to review.

HCD Requests Public Comments by March 4: Cities are encouraged to carefully review the full report and provide written comments to HCD by Saturday, March 4, 2017. Comments and questions can be submitted via email to sha@hcd.ca.gov. As part of the public process, HCD has scheduled several statewide housing assessment public workshops. The workshops are scheduled as follows:

- Fresno: Jan. 30 from 1:00 p.m. - 4:30 p.m.
- Los Angeles: Feb. 3 1:00 p.m. - 4:30 p.m.
- Sacramento: Feb. 6 1:00 p.m. - 4:30 p.m.
- Redding: Feb. 24 1:00 p.m. - 4:30 p.m.
- Bay Area: TBD

Next Steps: All cities should review HCD's report and consider providing written comments by March 4, 2017. The League will continue to provide updates, host webinars, and solicit input throughout the year. Cities' involvement is critical to maintaining local land use authority, public engagement, and transparency. See move at http://www.cacities.org/Top/News/News-Articles/2017/January/League-Submits-Comprehensive-Comments-on-HCD-s-Dra?utm_campaign=website&utm_source=cacities.org&utm_medium=email#sthash.Ls5QXlRi.dpuf.

Prior Action:

January 19, 2017: The Technical Advisory Committee received report.

Fiscal Impact:

This item is informational only; therefore, there is no fiscal impact.

Attachments:

1. Prop 64 Informal Briefing flyer.
2. Riverside County General Division Meeting flyer.

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Item 4.M

Report from the League of California Cities

Attachment 1

Prop 64 Informal Briefing flyer

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LEAGUE MEMBERS ONLY

Informational Briefing on Prop. 64: Local Regulation and Taxation Under the AUMA

Overview

On November 8, 2016, the Control, Regulate, and Tax Adult Use of Marijuana Act ("AUMA" or "Act") passed, legalizing nonmedical use of marijuana by persons 21 years of age and over, and the personal cultivation of up to six marijuana plants. In addition, the AUMA will create a state regulatory and licensing system governing the commercial cultivation, testing, and distribution of nonmedical marijuana, and the manufacturing of nonmedical marijuana products.

TOPICS WILL INCLUDE

- **Summary of the Adult Use of Marijuana Act**
- **Key differences between Prop. 64 and the Medical Marijuana Regulation and Safety Act enacted in 2015**
- **Rules on personal use and personal cultivation**
- **State licensing**
- **Local regulation of commercial recreational marijuana operations**
- **Taxation**
- **Policy issues for local governments to consider**

BRIEFING DETAILS

Wednesday, February 15, 2017
1:00 – 3:30 pm

Mayors Ceremonial Room 7th Floor
3900 Main St.
Riverside, CA 92522

Tim Cromartie
League of California Cities
Legislative Representative

Michael Coleman
CaliforniaCityFinance.com
Fiscal Policy Advisor

WHO SHOULD ATTEND

Mayors • Council Members • City Managers/ Assistant City Managers • Fiscal Officers City Planners • City Attorneys • Law Enforcement

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TO REGISTER: please visit www.cacities.org/events. For questions, please contact Sarah Nowshiravan at 916-658-8204 or snowshiravan@cacities.org.

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Item 4.M

Report from the League of California Cities

Attachment 2

Riverside County General Division Meeting flyer

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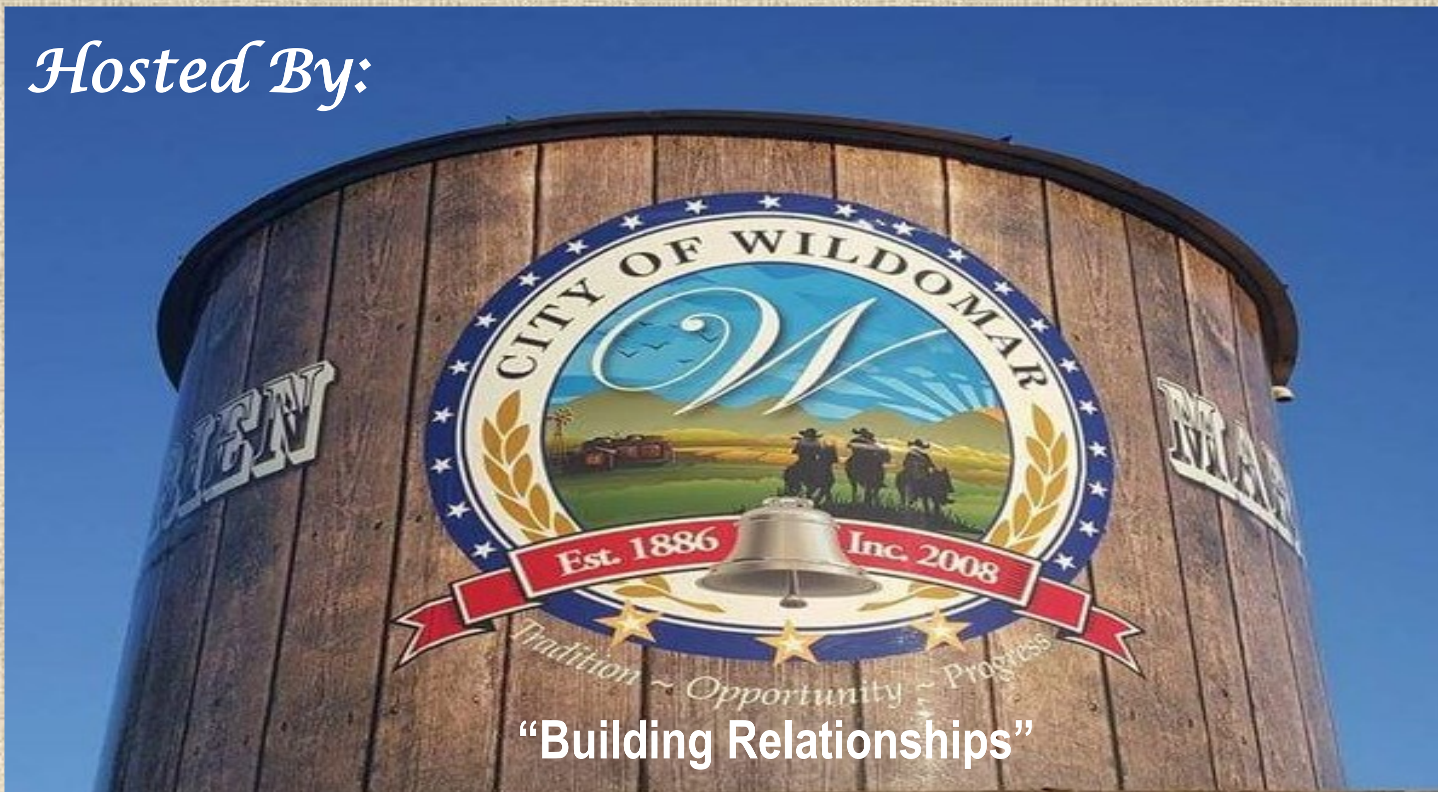
LEAGUE® OF CALIFORNIA CITIES

Riverside County Division General Meeting

Rescheduled to:

Monday February 13, 2017



The Corporate Room

34846 Monte Vista Drive Wildomar, CA 92595

4:00PM City Manager's Meeting (Wildomar City Hall 23873 Clinton Keith Rd.)

5:30PM Check in / Reception

6:00PM Dinner and Message from Speaker "Rocky Osborn"

Cost: $25.00 per Person

Meal Choice: Tri-tip, Chicken, Vegetarian

Please re- RSVP by February 1, 2017 to Araceli Corona

acorona@cityofwildomar.org or call 951-677-7751x200

MAKE CHECKS PAYABLE TO:

League of California Cities

6185 Magnolia Ave. Suite 360 Riverside, CA 92506

Sponsored By:

CR&R INCORPORATED environmental services

WM WASTE MANAGEMENT

INTERWEST CONSULTING GROUP

DeJONG'S DAIRY

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Item 6.A

Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **PACE Program Activities Update**

Contact: **Barbara Spoonhour, Director of Energy and Environmental Programs, spoonhour@wrcog.cog.ca.us, (951) 955-8313**

Date: **February 6, 2017**

***The purpose of this item is to** provide the Executive Committee with an update on the PACE Programs that WRCOG oversees. This includes the HERO Program, CaliforniaFIRST, and Spruce Finance.*

Requested Action:

1. Support the WRCOG PACE Ad Hoc Committee's recommendation for the HERO Program to implement some new rate options, and direct staff to return in 90-days with a report on Program revisions and impacts.

WRCOG's PACE Programs provide financing to property owners to implement a range of energy saving, renewable energy, and water conserving improvements to their homes and businesses. Improvements must be permanently fixed to the property and must meet certain criteria to be eligible for financing. Financing is paid back through a lien placed on the property tax bill. The HERO Program was initiated in December 2011 and has been expanded (an effort called "California HERO") to allow for jurisdictions throughout the state to join WRCOG's Program and allow property owners in these jurisdictions to participate. The CaliforniaFirst and Spruce Programs are planned to launch under the WRCOG Program PACE umbrella in 1st Quarter 2017.

Overall HERO Program Activities Update

Residential: As of January 20, 2017, over 156,200 applications in both the WRCOG and California HERO Programs have been approved to fund more than $1.4 billion in eligible renewable energy, energy efficiency and water efficiency projects.

WRCOG Subregion: As of January 20, 2017, a total of 22,275 projects, totaling over $430 million, have been completed (Attachment 1).

Statewide Program: As of this writing, 361 jurisdictions outside the WRCOG and San Bernardino Associated Governments' (now known as San Bernardino Council of Governments) subregions have adopted Resolutions of Participation for the California HERO Program. Over 41,300 projects have been completed, totaling over $886 million (Attachment 2).

The table below provides a summary of the total estimated economic and environmental impacts for projects completed in both the WRCOG and the California HERO Programs to date:

Economic and Environmental Impacts Calculations	
KW Hours Saved – Annually	667 GWh

GHG Reductions – Annually	175,157 Tons
Gallons Saved – Annually	403 Million
$ Saved – Annually	$89.3 Million
Projected Annual Economic Impact	$2.94 Billion
Projected Annual Job Creation/Retention	14,476 Jobs

The table below provides a summary of the estimated work breakdown of projects completed in both the WRCOG and the California HERO Programs:

Project Data	
HVAC	30.3%
Windows / Doors	19.2%
Solar	19.6%
Roofing	10.2%
Landscape	9.2%

HERO Program Update

Dealer / Contractor Fee Proposal: On January 11, 2017, the Administration & Finance Committee received a presentation regarding the inclusion of lower interest rates using dealer / contractor fees for the HERO Program. After discussion, the Administration & Finance Committee had some additional questions regarding homeowner impacts, small and mid-sized contractor participation, and impact to Renovate America's bottom line, and directed the item to be discussed with the WRCOG PACE Ad Hoc Committee. The Administration & Finance Committee also gave the PACE Ad Hoc Committee the authority to make a direct recommendation to the Executive Committee in February.

On January 25, 2017, the PACE Ad Hoc Committee received a presentation from Renovate America on the below questions raised from the Administration & Finance Committee members and are recommending that the Executive Committee move forward with implementing, in addition to its current interest rates, a dealer / contractor fee program that would provide lower interest rates to property owners that take advantage of the HERO Program.

The implementation of a dealer / contractor fee model will offer lower interest rate options to HERO homeowners through a contractor fee model – a model ubiquitous in the home improvement finance industry, and retail finance in general. In short, contractors pay a percentage of the project cost to Renovate America to offer a lower interest rate to the homeowner. By introducing lower interest rate options via a contractor fee, the HERO Program can position itself better than how it's positioned today relative to other payment options.

In addition to the Program's current interest rates with no dealer / contractor fees, the contractors will be able to select from several different rate sets. Contractors will only be able to offer those rates for a period of 90 days in order to give the model stability in tracking and to ensure contractors are not "bouncing" back and forth between rate sets. During the initial 90 days after implementation of this proposal, the Program will allow contractors to change their rate selection one time, helping to mitigate any unintended consequences stemming from selecting the improper rate set for their respective business. After that initial period, the contractor will have a rate enrollment period every 90 days, but it's important to note that the Program will not solicit the contractors to make changes.

Homeowner Savings: Each term set provides significant savings for all homeowners over HERO's existing rate set. Based on an average assessment amount of $18,100, homeowners would save up to the following in total payments over the life of their assessments (using the 5 and 25 year bookends, respectively).

Total Payment Savings Over Current HERO Rates	5 Years	25 Years
Rate Set 2	$875	$4,183
Rate Set 3	$1,553	$6,959
Rate Set 4	$2,546	$10,460

We expect the homeowner with the average assessment would save $6,700 if they took their obligation to term and still thousands of dollars if they prepay their assessment beforehand. As noted above, because of how PACE law works, the savings will be able to be realized by all homeowners, even those homeowners with lower credit scores who typically are not able to get access to lower interest rates.

The following are the questions asked by the Administration & Finance Committee:

1. *How will the HERO Program ensure that the contractor fees will not be passed on?*

- Renovate America will add a ban on direct fee passage to its existing contractor participation agreement.
- Renovate America will verify with all homeowners that they were not offered a different price for HERO than any other financing option or cash.
- HERO will track project cost trends by contractors as an additional screen.
- On a monthly basis, if an instance is found of a fee being directly passed on, HERO will ensure the contractor refunds the overage.
- Additionally, this infraction will be monitored through HERO's Contractor Management System and could result in suspension or termination.

2. *How will small to mid-size contractors be impacted?*

- This proposal will enable them to grow their businesses in a competitive marketplace.
  - Most contractors already use financing with contractor fees.
  - Average contractor fee in the market is 12.4%.
- The HERO Program is proposing rate sets where the average contractor fee is less than what they are currently paying with other financing options.
- By offering multiple rate sets – including the current term set with no contractor fee – the contractor can choose which rate and fee structure is for best for their business model.

3. *How does this impact Renovate America's bottom line?*

- These rates will lower Renovate America's revenue per assessment.
- It is expected that an increase in origination volume due to more competitive interest rates and broader customer interest will offset the per assessment reduction in revenue.

WRCOG staff and Renovate America have determined the following review reporting criteria that will occur on a monthly basis. This will allow staff the opportunity to review the performance of the new rate sets and to determine whether or not there need to be any changes brought back to the WRCOG PACE Ad Hoc Committee for consideration.

Improvement	Performance Criteria
Lower payments for homeowners	Track savings to homeowners and report on Compliance cases if the direct passage of a fee is detected
Higher customer satisfaction	Compare historical customer satisfaction results to current results to see if customer satisfaction is higher with the new rates
More favorable views of the Program	Provide anecdotal evidence of public comment

Lower average prices of projects	Track and compare average project prices to historical data
Fewer complaints about contractors	As part of an overall contractor management protocol, HERO will continue reporting on contractor complaints looking for trends in the data related to the introduction of the fee
Fewer mortgage foreclosures and lower foreclosure rates	Continue to track any instances of mortgage foreclosures and foreclosure rates
Lower property tax delinquency rates	Continue to track property tax delinquency rates
Greater energy and water savings and economic impact	Continue to track the projects funded and the impact of the projects on energy savings and water savings as well as jobs created

Additional PACE Providers

During the last several months staff have conducted additional site visits with CaliforniaFirst and Spruce to work through the mechanics of implementing these Programs within the Western Riverside subregion. Staff expects to bring the final agreement with CaliforniaFIRST to the March 6, 2017, Executive Committee meeting and could start accepting CaliforniaFIRST applications the next day depending on the Executive Committee's action. WRCOG is still working with Spruce to launch their PACE Program in spring 2017. Jurisdictions in Western Riverside County have the discretion to allow any PACE Program provider to operate in their city or county, regardless of whether that provider is operating under WRCOG's PACE Program umbrella.

Staff has also received inquiries from additional PACE providers who have expressed interest in operating in the WRCOG subregion under the WRCOG PACE Program umbrella. To begin the process, a potential PACE provider needs to submit a response to a staff questionnaire, agree to an on-site inspection, and interview with the PACE Ad Hoc Committee. Staff will reconvene the PACE Ad Hoc Committee on an "as needed" basis to evaluate these interested PACE providers.

Prior Actions:

January 25, 2017: The PACE Ad Hoc Committee recommended that the Executive Committee move forward with implementing, in addition to its current interest rates, a dealer / contractor fee program that would provide lower interest rates to property owners utilizing the HERO Program.

January 19, 2017: The Technical Advisory Committee received report.

January 11, 2017: The Administration & Finance Committee directed the PACE Ad Hoc Committee to meet and make a recommendation to the Executive Committee at its February 2017 meeting regarding the lowering of HERO Program interest rates.

January 9, 2017: The Executive Committee 1) received summary of the Revised California HERO Program Report; 2) conducted a Public Hearing Regarding the Inclusion of the Counties of Colusa, Mendocino, and Siskiyou Unincorporated areas, for purposes of considering the modification of the Program Report for the California HERO Program to increase the Program Area to include such additional jurisdictions and to hear all interested persons that may appear to support or object to, or inquire about the Program; and 3) adopted WRCOG Resolution Number 01-17; A Resolution of the Executive Committee of the Western Riverside Council of Governments Confirming Modification of the California HERO Program Report so as to expand the Program Area within which Contractual Assessments may be offered.

Fiscal Impact:

HERO revenues and expenditures for the WRCOG and California HERO Programs are allocated in the Fiscal Year 2016/2017 Budget under the Energy Department.

<u>Attachments</u>:

1. WRCOG HERO Snapshot.
2. CA HERO Snapshot.

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Item 6.A

PACE Program Activities Update

Attachment 1

WRCOG HERO Snapshot

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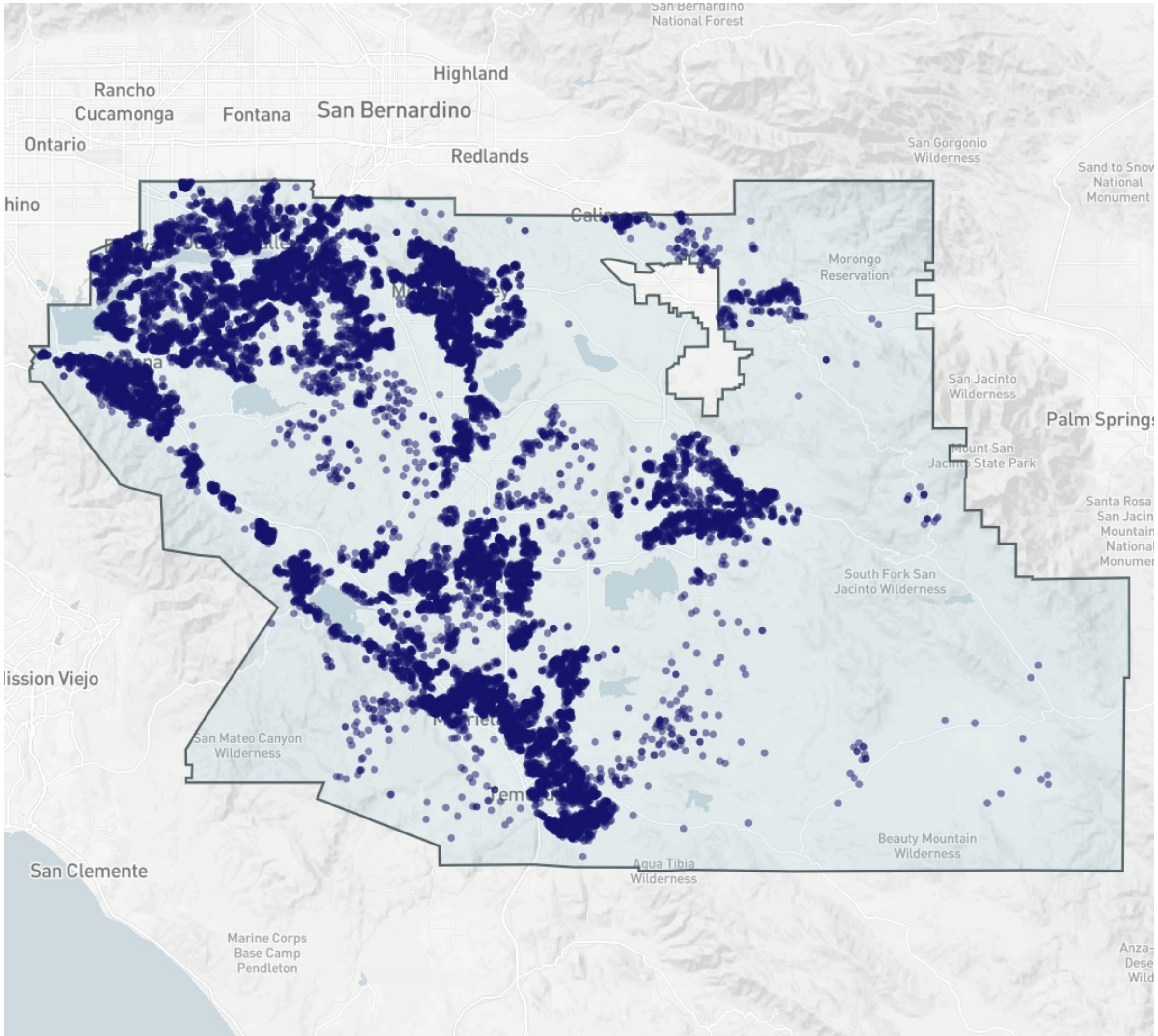
WRCOG - Western Riverside Council of Governments - WRCOG Program

19,100 Homes Improved

12/14/2011
HERO Launch Date

460,685
Housing Count

01/01/2011 - 01/20/2017
Report Range



Improvements

Type	Total Installed	Bill Savings
Energy	25.4K	$294M
Solar	12.3K	$518M
Water	1,718	$12.7M

Lifetime Impact

Applications Submitted	52.2K
Applications Approved	35.5K
Funded Amount	$431M
Economic Stimulus	$746M
Jobs Created	3,656
Energy Saved	3.16B kWh
Emissions Reduced	854K tons
Water Saved	1.38B gal

Learn how these numbers are calculated at https://www.herogov.com/faq

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Item 6.A

PACE Program Activities Update

Attachment 2

CA HERO Snapshot

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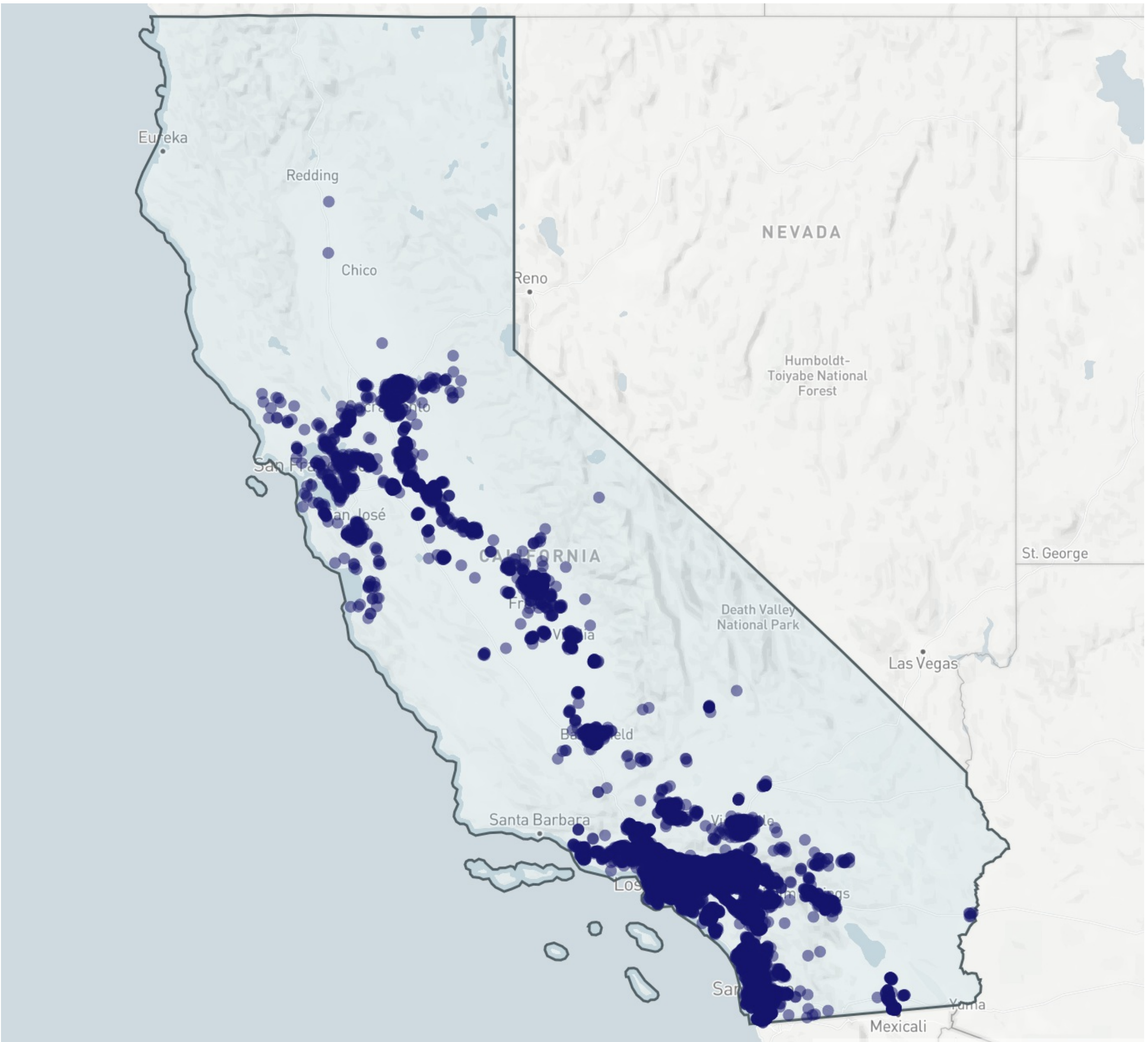
California HERO Program

37,331 Homes Improved

02/10/2014
HERO Launch Date

5,645,047
Housing Count

02/10/2014 - 01/20/2017
Report Range



Improvements

Type	Total Installed	Bill Savings
Energy	52.3K	$627M
Solar	21.4K	$987M
Water	3,960	$31.5M

Lifetime Impact

Applications Submitted	104K
Applications Approved	76.6K
Funded Amount	900M
Economic Stimulus	$1.56B
Jobs Created	7,638
Energy Saved	5.74B kWh
Emissions Reduced	1.52M tons
Water Saved	3.40B gal

Learn how these numbers are calculated at https://www.herogov.com/faq

hero GOV 855-HERO-411 gov@heroprogram.com

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Item 6.B

Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **Community Choice Aggregation Program Activities Update**

Contact: **Barbara Spoonhour, Director of Energy and Environmental Programs, spoonhour@wrcog.cog.ca.us, (951) 955-8313**

Date: **February 6, 2017**

***The purpose of this item is to** provide the Committee with an update on efforts to examine the feasibly of a Community Choice Aggregation Program for either the subregion, Riverside County, or two Counties (Riverside and San Bernardino).*

Requested Actions:

1. Receive the final draft Inland Choice Power Community Choice Aggregation Business Plan.
2. Direct the Executive Director to prepare and issue a Request for Proposals for CCA contract services.

Community Choice Aggregation (CCA) allows cities and counties to aggregate their buying power to secure electrical energy supply contracts on a region-wide basis. In California, CCA (Assembly Bill 117) was chaptered in September 2002 and allows for local jurisdictions to form a CCA for this purpose. Several local jurisdictions throughout California are pursuing formation of CCAs as a way to lower energy costs and/or provide "greener" energy supply. WRCOG's Executive Committee has directed staff to pursue the feasibility of Community Choice Aggregation for Western Riverside County. WRCOG, the San Bernardino Associated Governments, now known as San Bernardino Council of Governments (SBCOG) and Coachella Valley Association of Governments (CVAG) have funded a joint, two-county feasibility study in response to the Executive Committee's direction; the study has recently been completed.

CCA Activities Update

In January 2016, staff received direction from the Executive Committee to pursue a Feasibility Study for the potential formation of a CCA Program. To achieve economies of scale and resource efficiencies, San Bernardino Associated Governments, now known as San Bernardino Council of Governments (SBCOG) and the Coachella Valley Association of Governments (CVAG) joined WRCOG's effort to have a multi-county study completed. To complete the Feasibility Study, WRCOG entered into an agreement with BKi.

On October 3, 2016, the Executive Committee directed staff to move forward with the development of a CCA Program and to return with recommendations from the Administration & Finance Committee on governance and operational structures.

On January 11, 2017, the Administration & Finance Committee recommended that the Executive Committee receive the 4th and final Draft Feasibility Study (Attachment 1) and to authorize staff to release a Request for Proposal (RFP) for CCA services.

The Final Study outlines the preliminary data and key findings regarding the feasibility of a CCA for the two-county region, including data and findings for the Western Riverside, San Bernardino and Coachella Valley subregions separately. The Study concludes that the feasibility of developing a CCA is favorable, using a number of conservative assumptions.

The Study concludes that the formation of Inland Choice Power (ICP) – a two county CCA - in the service areas of CVAG, SBCOG and WRCOG is financially prudent and will yield considerable benefits for future ICP residents and businesses. These benefits include a 4.9% lower rate for energy if supplied at roughly the same renewable mix as is currently supplied by SCE, and at least a 3.8 percent lower rate for electricity (assuming a 50 percent renewable energy scenario – which is nearly twice the amount of renewables currently provided by SCE to customers) than is charged by SCE. With the achievement of Phase 2 level of operations (e.g. full implementation of a CCA), and all customers in the three subregions deemed eligible to participate, ICP would reduce greenhouse gas emissions by as much as 2.34 million metric tons of CO_2e per year, add over 500 jobs, generate over $54 million in additional gross domestic product, and give residents and businesses choice regarding their power supply and energy efficiency programs. Key to the formation of a CCA is that it provides consumers with additional choices regarding their energy consumption. The study concludes that even with these stated rate savings, significant funding could be generated to support new programs, local energy projects, and/or provide additional rate savings to the CCA's customers.

The separate formation of smaller, subregional CCAs for the Coachella Valley, Western Riverside and San Bernardino County is financially feasible and results in beneficial environmental / economic impacts. According to the study, a joint CCA (two counties combined) with common back office functions and local options for program development is the most economical operational option. Staff will continue to examine the pros and cons of the geographic models to help inform future discussions among the Executive Committee. Staff also desires to release a RFP for CCA contract which will request solicitors to provide bid estimates for various CCA operational components; this will also help to provide information on the potential costs of a fully outsourced CCA operating at the various geographies discussed above.

Some highlights from the final Study include:

<u>Consumer cost savings</u>: The combined savings for both Counties (taking into account the generation savings with the SCE distribution cost assumptions) are:

- 4.9% savings with a 33% renewable
- 3.8% savings with a 50% renewable (11.2% lower than SCE's 50% Green Rate)
- 5.7% higher with a 100% renewable (9.4% lower than SCE's 100% Green Rate)

<u>Implementation / start-up costs</u>: The Study examines implementation of a CCA from the "ground-up" and uses very conservative numbers and participation estimates, for example, to determine whether or not a CCA is feasible. In examining the two counties joining together, a number of the implementation / start-up costs would be reduced compared to CCAs operating at the smaller geographies.

Exhibit 23
Start-Up Costs Summarized by Phase (ICP)

		Phase 1	Phase 2
	Total 2017 Pre-Start Costs	July – December 2017	CY 2018
Start-Up Costs			
Infrastructure	$90,000	$260,000	$350,000
Consultants (incl. Data Manager)	$620,000	$1,471,529	$15,724,632
Staffing	$90,000	$970,000	$2,488,333
Utility Trans. Fee	$250,165	$3,574,050	$8,197,628
Total Start-Up	**$1,050,165**	**$6,275,579**	**$26,760,549**

However, if 3 separate CCAs were formed (one for each of the subregion geographies), there would still be savings. This is due to the fact that a number of the start-up costs would not be needed or would be reduced if the COGs played an active role in the implementation (i.e., infrastructure and staffing, etc.).

Exhibit 36 Start-Up Costs for Three CCAs Summarized by Phase						
	CVAG 2017	CVAG 2018	SANBAG 2017	SANBAG 2018	WRCOG 2017	WRCOG 2018
Start-Up Costs						
Infrastructure	$240,000	$350,000	$350,000	$350,000	$240,000	$420,000
Consultants	$1,226,215	$2,398,639	$1,792,679	$9,074,423	$1,552,634	$6,331,569
Staffing	$400,000	$1,190,000	$1,060,000	$2,488,333	$400,000	$1,704,167
Utility Trans. Fee	$453,211	$918,803	$2,088,921	$4,405,258	$1,297,475	$2,873,783
Total Start-Up	**$2,319,426**	**$4,857,442**	**$5,291,600**	**$16,318,014**	**$3,490,109**	**$11,329,519**

Economic Development Impacts: The Study outlines enhanced local economic development that could occur with the formation of a CCA. The analyses contained in this Study focused primarily on the direct effects of this formation. However, in addition to direct effects, indirect economic effects are also estimated. The indirect effects of creating a CCA include the effects of increased local investments, increased disposable income due to bill savings, and improved environmental and health conditions.

In total, approximately 547 jobs are projected to be created in the TRICOG region through the implementation of a CCA. The TRICOG region is also projected to have a labor income impact of over $24.0 million, a total value added impact of approximately $37.2 million, and an output impact over $54.9 million.

SCE Rates and Surcharges: The base case forecast of SCE rates assumes delivery rates increase at 2 percent per year and generation rates increase approximately 2 percent based on the projected market prices and renewable resource growth rates. Additionally, SCE's generation cost was modeled in the high and low case by incorporating the expected range of market and renewable resource costs.

The level of the Power Cost Indifference Adjustment (PCIA), or Exit Fee, will impact the cost competiveness of a CCA. In order to be cost-effective, CCA power supply costs plus PCIA and other surcharges must be lower than SCE's generation rates. Over time, the PCIA will vary, but it is expected that it will decline as market prices increase. The PCIA reflects SCE's own resources and signed contracts. Once the contracts expire, the related PCIA will disappear. Sensitivity to the PCIA has been modeled in the high case scenario by assuming the PCIA would increase to reflect a historic high of 2.5 cents per kWh and remain flat for the 20-year analysis period. For the low case scenario, it was assumed that the PCIA decreases by 50 percent in year one and remains flat for the 20-year analysis period.

Governance structures: One of the next steps in the implementation of a CCA will be to examine and ultimately determine a governance structure under which the CCA will operate. WRCOG has outlined seven different scenarios (summarized below) for further examination.

Once a governance structure has been determined, the development of the operational structure would then be decided. The operational structure will be largely based on the extent to which the Governing Board of a CCA desires to have CCA functions performed in house, outsourced, or in combination. As mentioned previously, staff desires to develop a RFP if the Executive Committee concurs with the recommendation in this report in order to solicit bids from the private sector on the costs of an outsourced model to help inform this analysis.

- **Two County CCA Scenario**

  This option will examine **jurisdictions within Riverside and San Bernardino Counties** moving forward with a single, two-county CCA.

  A JPA would need to be formed. According to WRCOG's legal counsel, a county providing a regional service can do so through a cooperative agreement with city partners and/or through an enterprise fund without establishing a JPA. In the case of CCAs, however, the statutory authority specifically defines the composition of an aggregator such that a county cannot provide CCA to incorporated area residents absent a JPA. PUC 331.1(a)-(b) and 366.2(c)(12)(A)- (B) define a community choice aggregator and specify CCA program requirements. An entity can elect to implement a CCA program within its jurisdiction, or two or more entities may elect to combine their loads through a joint powers agency.

PUC 331.1 was amended in 2011 by SB 790 (Leno) to add subsection (c), which expanded the entities that are permitted to undertake CCA. PUC 331.1(c) authorizes two non-JPAs, the Kings River Conservation District and Sonoma County Water Agency, and any California public agency possessing statutory authority to generate and deliver electricity at retail within its service territory to combine the loads of cities and counties within, or contiguous to, its jurisdiction that have elected to be served by the CCA.

In other words, a county would either need to have special legislation authorizing it to provide CCA in incorporated areas or it would need to be a public owned electric utility where “city customers” have opted into the program.

Scenario 1: *Formation of a new JPA between Riverside and San Bernardino counties that has incorporated jurisdictions participating, and all operations would be performed/overseen by the JPA. Decisions on Board representation would be determined through the development of the JPA.*

Scenario 2: *Formation of a new JPA, where one of the 3 COGs (WRCOG, SBCOG, or CVAG) or one or more of the member jurisdictions takes the lead on the operational functions of the CCA and allows member jurisdictions from both counties to participate. Decisions on Board representation would be determined through the development of the JPA.*

- **One County Scenario**

This option examines jurisdictions within Riverside or San Bernardino Counties moving forward with the formation of a separate CCA for each County. **A JPA would need to be formed (see discussion above).**

Scenario 3: Formation of a new JPA between jurisdictions within Riverside or San Bernardino counties that has all operations performed/overseen by the JPA. Decisions on Board representation would be determined through the development of the JPA.

- **Individual Scenario for Coachella Valley, Western Riverside, San Bernardino areas**

This option examines that each of the COG regions (Coachella Valley, Western Riverside, and San Bernardino) would form and operate its own CCA. Scenarios include new JPA utilizing existing COG resources, a new JPA completely separate from the COGs, or amendments to existing COG JPAs to be made to allow the creation and operation/oversight of the CCA.

For WRCOG, this could mean the following:

Scenario 4: *WRCOG could amend its existing JPA to form a CCA for participating member jurisdictions. Member jurisdictions that wish to participate would need to take City Council or Board action to be included in the CCA. Those jurisdictions that elect not to participate or already have their own municipal utilities would not have input or representation on CCA activities. This is similar to the Transportation Uniform Mitigation Fee (TUMF) Program, where certain members that do not participate in TUMF do not vote on TUMF items.*

Scenario 5: *A new JPA - separate from WRCOG – could be formed and utilize WRCOG’s staffing and resources for the operations. This is similar to the Riverside County Habitat Conservation Authority (RCHCA), which operates under its own JPA but for which WRCOG administers the Program through a separate agreement with the RCHCA. Again, member jurisdictions that wish to participate would need to take City Council action to be included in the CCA.*

Scenario 6: *Formation of a new JPA, completely separate from WRCOG that would provide service to the Western Riverside subregion.*

- **Individual jurisdiction Scenario**

  This option is where a single jurisdiction establishes and administers its own CCA.

  Scenario 7: *Individual jurisdictions would create a CCA and operate under the jurisdiction.*

Operational structures: An analysis of potential operational structures for a CCA will examine hiring new staff, hiring a mix of staff and consultants, or hiring a third party to implement the CCA on behalf of the JPA.

To adequately examine the optimum operational structure for CCA operations – whether contracting with a third party entity, using staff, or utilizing a mix thereof in operating the CCA - WRCOG requests that the Executive Committee authorize staff to develop and release a RFP order to gain information from the private sector on the costs of a fully outsourced CCA at the geographies mentioned above.

Next Steps: In addition to identifying governance structures and further assessing operational costs through a bid process, there are other steps that need to be developed in moving forward:

January 2017:	Vet business plan and finalize
March 2017:	Determine governance preference
February 2017:	Release RFP for CCA implementation assistance
April 2017:	Select power supply and data management vendor
May 2017:	Adopt Resolution of Intent and File Implementation Plan with CPUC
May 2017:	File Notice of Intent with SCE
June/July 2017:	Arrange financing of start-up costs
May / November 2017:	SCE data testing
September / October 2017:	Opt-out notice – 1 and 2
November 2017:	Launch phase 1
November 2017:	Opt-out notices – 3 and 4

Prior Actions:

January 19, 2017: The Technical Advisory Committee 1) recommended that the Executive Committee receive the final draft Inland Choice Power Community Choice Aggregation Business Plan; and 2) directed the Executive Director to issue a Request for Proposals for CCA contract services.

January 11, 2017: The Administration & Finance Committee 1) recommended that the Executive Committee receive the final draft Inland Choice Power Community Choice Aggregation Business Plan; and 2) directed the Executive Director to issue a Request for Proposals for CCA contract services.

Fiscal Impact:

WRCOG's portion for Phase 1 is estimated to be $130,000 to cover the costs of the CCA Feasibility Study, SCE data request, and WRCOG staffing. The costs for this will come from existing carryover funds and will be reflected in an upcoming Quarterly Budget Amendment.

Attachment:

1. Inland Choice Power Community Choice Aggregation Business Plan – Final Draft – December 8, 2016.

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Item 6.B

Community Choice Aggregation Program Activities Update

Attachment 1

Inland Choice Power Community Choice Aggregation Business Plan – Final Draft – December 8, 2016

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FINAL DRAFT

Inland Choice Power
Community Choice Aggregation Business Plan

December 8, 2016

Prepared by:

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December 8, 2016

Ms. Katie Barrows	Mr. Duane Baker	Ms. Barbara Spoonhour
CVAG	SANBAG	WRCOG
73-710 Fred Waring Drive	1170 W. 3rd Street	4080 Lemon Street
Suite 200	2nd Floor	3rd Floor, MS 1032
Palm Desert, CA 92260	San Bernardino, CA 92410	Riverside, CA 92501

SUBJECT: Inland Choice Power Community Choice Aggregation Business Plan

Dear Ladies and Gentleman:

Please find attached EES Consulting, Inc.'s (EES) Final Draft Community Choice Aggregation (CCA) Business Plan (Plan) for Inland Choice Power (ICP). This Plan represents our work product in evaluating the prudency of implementing a CCA organization for Coachella Valley Association of Governments (CVAG), San Bernardino Associated Governments (SANBAG) and Western Riverside Council of Governments (WRCOG).

We want to thank you and your staff for your assistance in preparing this Plan. It has been a pleasure working with all of you on this project.

Please contact us directly if you have questions or if we may be of any further assistance. We will finalize this Plan after it has been reviewed and critiqued by all stakeholders, and meets with your final approval.

Very truly yours,

Gary Saleba
President/CEO

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Contents

Executive Summary

Background

The California legislature passed AB 117 in 2002 (amended in 2011 by SB 790) allowing all cities, counties, or groups of cities and counties to provide an electric power supply source to customers within their jurisdictions that are currently served by Southern California Edison, Pacific Gas & Electric or San Diego Gas & Electric (collectively the IOUs). Community Choice Aggregation (CCA) or Community Choice Energy (CCE) is a customer opt-out program where the CCA provides power supply and behind the meter services[1], and the incumbent IOUs provide transmission and distribution (wires) service.

This Business Plan (Plan) evaluates the prudency of forming a CCA within three government associations or geographical areas: Coachella Valley Association of Governments (CVAG), San Bernardino Associated Governments (SANBAG) and Western Riverside Council of Governments (WRCOG). Collectively, this CCA is referred to in this Plan as Inland Choice Power (ICP). The proposed CCA will provide power supply and behind the meter services, while Southern California Edison (SCE) will continue to provide transmission and distribution services. Customers will be part of the ICP program until they proactively opt-out.

This Plan estimates ICP's power supply costs, administrative costs, electric loads, and future retail rates and compares ICP's rates to the incumbent SCE rates. These forecast rates are compared to determine if a CCA can offer competitive rates, better products and/or superior customer service while also improving the environment and creating local jobs.

Business Plan Goal

The goal of the Business Plan is to use conservative numbers and analysis to show the feasibility of establishing a CCA in the geographical region(s) and to build the framework for the completion of an Implementation Plan that would need to be submitted to the California Public Utilities Commission (CPUC). Conservative assumptions are used throughout this Plan to ensure policymakers make sound policy decisions based on sound financial analysis.

Description of ICP

The Plan and structure of ICP are currently being analyzed by CVAG, SANBAG and WRCOG collectively. CVAG is the regional planning agency coordinating government services in the Coachella Valley, and has 10 cities, Riverside County, the Agua Caliente Band of Cahuilla Indians and the Cabazon Band of Mission Indians as members. SANBAG is the council of governments and transportation planning agency for San Bernardino County. SANBAG's members include 24

[1] For example, energy efficiency programs, net energy metering or other programs that promote the deployment of distributed energy resources.

cities and San Bernardino County. WRCOG's purpose is to unify Western Riverside County so that it can speak with a collective voice on important issues that affect its members and it consists of 17 cities, Riverside County Board of Supervisors, the Eastern and Western Municipal Water Districts, and the Morongo Band of Mission Indians. The geographic area and customer base covered by CVAG, SANBAG and WRCOG are collectively called Inland Choice Power.

Various organizational scenarios are explored in this Plan. For the Plan's "base case," results are provided assuming one organization or agency will operate a CCA for all three entities. This scenario is referred to as the "ICP" scenario and is the basis for the financial analysis throughout the Plan. This base case explores the prudency of full participation of all three COGs as one operating CCA. In addition, results are provided assuming three separate CCA's will be formed. This scenario is referred to in the Plan as the "Three CCA" scenario. The results for the individual COG's CCA option are analyzed starting at page 51 of this Plan and provide insight into CCA operations if not all jurisdictions participate. It is anticipated that the results of this Plan are scalable.

For this Plan, it is assumed that service will be offered to customers in two phases. Phase 1 will include the ICP members' municipal facilities in addition to 5 percent of non-municipal commercial facilities. In Phase 2, all customers located in the service area of ICP will be included in ICP. Exhibit ES-1 summarizes this phased approach to forming ICP, including the number of customers and load attendant with each phase. ICP's total loads will represent roughly 30 percent of SCE's total current electrical loads. The assumed start date is an aggressive estimate but is used throughout the Business Plan to retain consistency in the calculations.

Exhibit ES-1
CCA Load, Customers, and Revenue by Phase in 2017*

Phase	Assumed Start	Eligibility	Customer Accounts	Peak Load*** (MW)	Average Load*** (aMW)	ICP Annual Revenues (50% RPS)
ICP						
Phase 1**	July, 2017	Municipal + 5% Commercial	69,669	73	49	$24 million
Phase 2	January 2018	All Customers	961,139	3,951	1,720	$963 Million
CVAG						
Phase 1**	July, 2017	Municipal + 5% Commercial	10,116	7	6	$3.2 Million
Phase 2	January 2018	All Customers	108,594	517	209	$125 Million
SANBAG						
Phase 1**	July, 2017	Municipal + 5% Commercial	41,208	44	29	$13.8 Million
Phase 2	January 2018	All Customers	517,717	2,126	955	$535 Million
WRCOG						
Phase 1**	July, 2017	Municipal + 5% Commercial	18,346	22	14	$7.0 Million
Phase 2	January 2018	All Customers	334,828	1,343	555	$321 Million

* Estimates assume a 75% participation rate for residential customers, and a 65% participation rate for non-residential customers.

** Phase 1 is assumed to run July – December of 2017. Therefore, load and revenue for this phase is estimated annual.

*** Loads are expressed as wholesale, including losses of 6%.

This phasing strategy enables ICP to manage any start-up and operational issues before full scale operations are undertaken. In addition, this phasing strategy will allow ICP's third party electricity suppliers, scheduling agents and data management entities to ramp up power supply procurement and bill processing over several months.

This Business Plan was started with the assumption that all member cities of the three COGs as well as both counties' unincorporated areas would participate. Consequently, the electric load forecast for the ICP service area includes the load of the unincorporated Counties of Riverside and San Bernardino. During preparation of the Plan, Riverside County opted to move forward with preparation of its own CCA Implementation Plan, separate from the ICP effort. Appendix C provides the results for feasibility of ICP if the County of Riverside unincorporated area loads are not included in this Plan's load projections.

Governance Structure Options

This Business Plan examines two governance structures. The governance structures differ from the operational structures. The governance structure determines what entity would be responsible for policy direction operations of the CCA and ongoing reporting requirements. These governance structure options include:

1. **Single Jurisdiction Model:** A jurisdiction individually establishes and operates a CCA and therefore makes all policy decisions on revenues, power mix, and programs. Any risk and liability associated with the CCA fall solely on this single jurisdiction. In this model, it is recommended that the jurisdiction develop contractual language to minimize risk to the general fund, maintain adequate operating reserves, and proactively track regulatory activities and manage its energy portfolio. Lancaster Choice Energy and CleanPowerSF are examples of single jurisdiction governance models.

2. **Joint Powers Authority (JPA) Model**: The JPA functions as an independent public agency, operating on behalf of its member jurisdictions with shared decision-making authority. This shared structure distributes the risks and liability across multiple jurisdictions, and minimizes risk to its member jurisdictions. Marin Clean Energy, Sonoma Clean Power, and Peninsula Clean Energy are examples of CCAs using the JPA model.

Within each of these governance structure options, there are several scenarios that can be utilized. Given that CVAG, SANBAG, and WRCOG are already each a JPA, it is anticipated that a JPA will be the governing model for the ICP. In the event that ICP forms as three separate CCAs, the existing JPAs of CVAG, SANBAG, and WRCOG may need to be amended to allow for the implementation of a CCA. Alternatively, if ICP elects to launch a single unified CCA, a new JPA could be formed or one of the existing JPAs could be amended to allow other agencies to join for the purposes of implementing the ICP. The governance of a JPA anticipates that a governing board (Board) of elected officials will set policies and procedures for an Executive Director, who will be entrusted to manage the day-to-day operations of the CCA.

Operational Structure Options

Operation of the CCA will involve a range of day-to-day functions including:

- Marketing and outreach
- Power supply contracts and scheduling
- Billing and data transfer with the IOU
- Regulatory compliance with the California Public Utility Commission (CPUC)
- Monitoring regulatory and legislative energy policy relevant to CCA competitiveness

These functions can be fulfilled by internal staff, external consultants, or a mix thereof. The choice of how to allocate these functions between internal and external resources will be at the discretion of the governing Board of the CCA.

For start-up, the Plan assumes that regardless of whether a single jurisdiction or a joint JPA is formed as the CCA's governance structure, an operating team will be employed consisting of an Interim Executive Director, per the example of other CCAs in California plus a few other CCA technical staff. This operating team can either be built by using existing staff or hiring new staff. This team would then be supported by outside consultants to assist with the management of the CCA, until Phase 2 is implemented.

For the longer term and into Phase 2 launch, ICP has three options for staffing after the initial start-up. The first option involves hiring internal staff incrementally to match workloads involved in forming ICP, managing contracts, and initiating customer outreach/marketing during the pre-operations period (Full Staff Scenario). In option two, the CCA would hire just a few staff internally and contract out the remaining work to consultants (Minimum Staff Scenario). In the third option, ICP would contract with one or more third-parties to complete all the operational aspects of the CCA. Throughout the rest of this Plan, it is assumed that ICP will transition to the Full Staff Scenario. This scenario represents the highest cost scenario so as to maintain a conservative posture for the Plan's financial proformas. Less costly options may be available to the CCA based on subsequent request for proposals to evaluate other staffing options.

It should be noted that the existing California CCAs have opted for an organizational structure that features a significant number of internal staff as opposed to using all consultants to operate their CCA. There are many reasons for this type of operational structure but two primary reasons are:

- The size of the CCA is such that in most cases it is the largest enterprise found among the CCA participants.
- This CCA will have direct contact with most of the governing body's constituents at least once a month through the CCA billing process.

Because of these noteworthy observations, existing CCAs have adopted more of a "hands on" organizational structure, but the preferred operational mode for a new CCA is ultimately dictated by the Board.

Plan Uncertainties/Risks

The results of this Plan are subject to uncertainties. These uncertainties are evaluated in the Plan's sensitivity analysis section. The list below provides a summary discussion of the key uncertainties associated with this Plan.

- Market Price Forecasts – Market prices (and forecasts) are continually changing. The market price forecasts for electricity and natural gas utilized in this Plan are based on the best currently available information regarding future natural gas and electricity prices, and have been confirmed by recent wholesale power transactions in southern California. These types of forecasts vary over time. Thus, a range of market price forecasts are evaluated in the Plan's sensitivity analysis.
- Retail Rate Forecasts – The Plan forecasts both ICP and SCE retail rates. These forecasts are based on current information regarding inflation and other cost drivers. Unexpected impacts on rates are discussed in more detail in the Plan's sensitivity analysis.
- Forecasted Load and Customer Growth – The Plan bases the load forecasts on customer growth assumptions. Each of these forecasts includes a level of uncertainty. To illustrate the impacts of load uncertainty, low, medium, and high load forecasts are analyzed in the Plan's sensitivity analysis.
- Regulatory Risks – Unforeseen changes in legislation (California Public Utility Commission, State legislation and Federal legislation) may impact the results of this Plan. Sensitivities on these risks are also provided.

This sensitivity analysis shows that the ICP rates could be greater than SCE rates if:

- The Power Charge Indifference Adjustment (PCIA) becomes much larger. The PCIA is a charge assessed by the IOU to cover generation costs acquired prior to CCA formation, sometimes referred to as stranded costs,
- ICP loads are much less than forecast, and
- Wholesale market prices drop much lower than current rates after ICP enters power contracts, allowing SCE a temporary advantage on generation rates.

Each of these three scenarios has a low probability of actually occurring. For example, wholesale market prices for natural gas and electricity are at all-time lows. The probability of any significantly further lowering of these prices is judged to be very small. The PCIA level should be fairly stable going forward as regulatory remedies are in play to stabilize the CCA and because the CCA community has become very vigilant in this area. Finally, this Plan assumes a relatively low customer participation rate of 75 percent for residential customers and 65 percent for non-residential customers, compared to the roughly 95 percent to 85 percent participation rates seen in California's currently operating CCAs. It is very unlikely ICP loads will not meet or exceed those assumed in the Plan. Thus, the major risks of forming a CCA are manageable and small.

Retail Rate Construct

This Plan evaluates the costs and resulting rates of operating ICP, and compares these rates to a comparable rate forecast for SCE. The analysis begins with a forecast of electrical loads and customers, incorporates several power supply resource portfolio options, and allows for the sensitivity or stress testing of input assumptions. ICP customers will see no obvious changes in electric service other than lower prices and potential increases in renewable resources in their power supply resource mix. Customers will pay the power supply charges set by ICP and no longer pay the costs of SCE power supply.

ICP's power supply rate consists of power supply costs, ICP start-up costs, ICP staffing and operating costs, consulting support, SCE billing and regulatory charges, financing costs, reserves and SCE pass-through charges, such as the Power Cost Indifference Adjustment (PCIA) Charge, franchise charges, and other non-bypassable charges from SCE.

In addition to paying ICP's power supply rate, ICP customers will pay the SCE delivery (wires) rate and all other non-power supply related charges on the SCE bill including the Utility User Taxes.

ICP will establish rates sufficient to recover all costs related to operation of the CCA. It is anticipated that ICP's rate designs initially will mirror the structure of SCE's rates with an appropriate discount so that rates similar to SCE's can be provided to ICP's customers. In setting rates, the Plan's financial analysis assumes the customer phase-in schedule noted above and assumes that the implementation costs are largely financed via a start-up loan.

The information above is used to determine the retail rates for ICP. ICP rates are then compared to the SCE projected rates for ICP service area.

Generation Municipal Surcharge (or Franchise Fee)

The franchise fee is a surcharge that SCE pays cities and counties for the right to use public streets to provide utility services. Under CCA operations, SCE will continue to collect the franchise fees for both generation and distribution services and pay the cities and counties the owed revenue. The franchise fee is not forecast to change during the analysis horizon, and will remain consistent with current franchise fee payments from SCE.

Retail Rate Forecast of SCE versus ICP

The first benefit for forming ICP is the retail rate impact as illustrated on Exhibit ES-2. For this Plan, it has been assumed that the projected rate decrease is applied uniformly across all rate classes. Once established, it will be up to the ICP Board and staff to develop rates for each rate class that reflect cost of service. Exhibit ES-2 compares SCE's current total bundled rates based on the current Renewables Portfolio Standard (RPS), SCE's 50% Green Rate and 100% Green Rate compared to three comparable ICP rate options.

For reference, the column headers noted on ES-2 are summarized below.

- RPS Bundled – ICP rates with the same share (currently 28 percent) of renewables as SCE's current power supply.
- 50% Green Bundled Rate – ICP rates with 50 percent renewable power.
- 100% Green Bundled Rates – ICP rates with 100 percent renewable power.

A rate schedule comparison of ICP's rates and SCE's rates follows.

Exhibit ES-2
Indicative Rate Comparison in ¢/kWh (First Full Year of Service)

Rate Class	Customer Type	2017 Estimated SCE Bundled Rate*	ICP RPS Bundled Rate	SCE 50% Green Bundled Rate	ICP 50% Green Bundled Rate	SCE 100% Green Bundled Rate	ICP 100% Green Bundled Rate
Residential	Domestic	20.55	19.58	22.30	19.81	24.05	21.79
Residential Care	Domestic	12.22	11.64	13.97	11.78	15.72	12.96
GS-1	Commercial	17.03	16.23	18.78	16.41	20.53	18.06
GS-2	Commercial	16.57	15.79	18.32	15.97	20.07	17.57
GS-3	Industrial	14.71	14.02	16.46	14.18	18.21	15.60
PA-2	Public Authority	13.08	12.46	14.83	12.61	16.58	13.87
PA-3	Public Authority	11.31	10.78	13.06	10.90	14.81	11.99
TOU-8 Secondary	Domestic	13.07	12.45	14.82	12.60	16.57	13.86
TOU-8 Primary	Commercial	11.84	11.28	13.59	11.41	15.34	12.55
TOU-8 Substation	Industrial	7.76	7.39	9.51	7.48	11.26	8.23
Initial Total ICP Rate Savings over Comparable SCE Rates of 50% or 100% Green			4.9%		11.2%		9.4%
Initial Total ICP Rate Savings over SCE's Standard Bundled Rate			4.9%		3.8%		-5.7%

*SCE bundled average rate based on SCE's ERRA 2017 Draft Filing

Appendix B contains the proformas to support Exhibit ES-2.

Exhibit ES-2 shows the initial rate savings associated with the formation of a CCA. By referencing Appendix B, these initial savings increase after ICP becomes fully functional. The savings by rate schedule after ICP is fully functional are presented below in Exhibit ES-3.

Exhibit ES-3
CCA Rate Savings at Fully Functional Operations

Power Supply Scenario	Range of Savings*
ICP 28% Renewable (RPS)	4.9% - 5.7%
ICP 50% Renewable	3.8% - 4.5%
ICP 100% Renewable	(5.7%) – (5.0%)

*Note Appendix B for detail.

The difference between the ICP bundled rate for residential consumers of 19.58¢/kWh and the ICP 50 percent renewable rate forecast of 19.81¢/kWh is close enough that the base case rate for this Plan is the ICP 50 percent renewable rate forecast. The difference in retail rates between the ICP RPS and the 50 percent green rate forecast is de minimis, and there are additional greenhouse gas (GHG) and economic development benefits associated with the 50 percent green power option being the Plan's base case; however, the final decision of the base case rate scenario for ICP will ultimately rest with ICP's Board. The 50 percent green baseline portfolio results initially in a savings over SCE's RPS rate of 3.8 percent.

It should be noted that the rate savings noted in ES-2 still allow the accumulation of significant reserves for ICP. As illustrated in Appendix B, the proformas include a line item called "Contribution to Annual Reserves" that go towards funding the needed cash working capital (approximately $284M). After the target reserves have been met, additional reserves can be used to further lower CCA retail rates for consumers, invest in local renewable projects, provide additional energy efficiency programs, and/or any other CCA-related activity as directed by the CCA's Board. The projected funds available for this purpose are provided in the line item titled "New Programs" in the proforma. The accumulate reserves and new program accruals present the new CCA with a large amount of funding and numerous opportunities going forward.

Exhibit ES-4 highlights how much financial reserves are generated with the rate reductions noted above.

Exhibit ES-4
Accumulative Fund Balances for Financial Reserves and New Programs Under the 50% Renewable

Year	Accumulative Financial Reserve Funds ($ x 1000)	Accumulative New Project Funds ($ x 1000)	Total Financial Reserves ($ x 1,000)
2018	$63,330	$0	$63,330
2019	$130,225	$0	$130,225
2020	$213,504	$0	$213,504
2021	$259,527	$46,022	$305,549
2022	$259,527	$147,956	$407,483
2023	$259,527	$262,232	$521,759
2024	$259,527	$384,563	$644,090
2025	$259,527	$515,637	$775,164
2026	$259,527	$653,238	$912,765
2027	$259,527	$796,925	$1,056,452
2028	$259,527	$946,175	$1,205,702
2029	$259,527	$1,101,642	$1,361,169
2030	$259,527	$1,254,153	$1,513,680

These new project and financial reserve fund balances can be used for CCA-related activities as directed by the Board. These fund balances can also be used for rate reductions larger than assumed in the Plan's base case, additional energy efficiency programs, development of load renewable projects and/or special rate programs.

Compliance with SCE and CPUC

ICP will be required to observe certain regulatory and operational obligations with the California Public Utilities Commission (CPUC) and with SCE. During the formation and launch of ICP, these obligations will include submitting an Implementation Plan, submitting a surety bond, and registering as a CCA all with the CPUC. Also during this phase, ICP will establish its credit-worthiness, test electronic data exchange, and negotiate a start-of-service date with SCE. After launching operations, ICP will prepare integrated resource plans (IRPs) and demonstrate compliance with renewable portfolio standards to the CPUC. The CPUC will have no control over the rates charged by the CCA or its various program offerings.

Renewable Energy Impacts

A second benefit of forming ICP is the potential for an increase in the energy supplied by renewable resources. The majority of this renewable energy will be met by renewable energy contracts or newly constructed renewable resources. By 2020, SCE must procure a minimum of 33 percent of its customers' annual electricity usage from renewable resources due to the State's Renewables Portfolio Standard (RPS) mandate and the Energy Action Plan requirements of the California Public Utilities Commission (CPUC). In contrast, ICP customers will procure at least 50 percent renewable power from day one of ICP's operation under the Plan's base case which will come from new and/or local renewable resources, thus significantly increasing the amount of renewable energy used by CCA customers.

Energy Efficiency Programs

A third benefit of the Plan is a potential increase in energy efficiency program investments and activities. The existing energy efficiency programs administered by SCE will not change as a result of forming ICP. ICP customers will continue to pay the Public Goods Charges to SCE which funds energy efficiency programs for all customers, regardless of power supply provider. The energy efficiency programs ultimately planned by ICP will be in addition to the level of energy efficiency investment currently provided by SCE. Thus, ICP has the potential to increase energy savings with an attendant reduction in greenhouse gas (GHG) emissions due to expanded energy efficiency programs.

Economic Development

The fourth benefit of ICP is increased local economic development. So far, the Plan's analysis has focused on the direct impacts of reduced rates associated with forming ICP. However, in addition to these direct effects, indirect economic effects will also be encountered. The indirect effects of creating ICP include increased local investments, in energy efficiency (EE) and distributed energy resources (DER), increased disposable income due to bill savings, and improved environmental and health conditions.

Exhibit ES-5 shows the economic impact resulting from $100 million in electric bill savings across the ICP service area. The $100 million rate savings represents an estimated bill savings per year achievable by ICP once Phase 2 operations are at steady state. It is estimated that these savings will create approximately 547 additional jobs in the ICP region and over $24.0 million in labor income. It is also projected that the total value added (revenues less cost of inputs) will be approximately $37.2 million and the total additional revenues and sales in the economy (output) is estimated to be over $54.9 million.

Exhibit ES-5 $100 Million Rate Savings Effects on ICP Economy				
Impact Type	**Employment**	**Labor Income**	**Total Value Added**	**Output**
Direct Effect	388.0	$18.2 million	$27.7 million	$36.5 million
Indirect Effect[2]	60.3	$2.1 million	$3.5 million	$6.3 million
Induced Effect[3]	98.3	$3.8 million	$7.0 million	$12.1 million
Total Effect	546.6	$24.1 million	$37.2 million	$54.9 million

In addition to increased economic activity due to electric bill savings, potential local projects can also create job and economic growth within the ICP service territory. As an example of the macroeconomic activity caused by local distributed energy resource (DER) deployment, this Plan analyzes the installation of 50 crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 50 MW. Overall, the building of a 50 MW solar project is projected to create $87 million in earnings and $188 million in output (GDP) in the local economy along with 1,636 jobs during construction and 14 full-time jobs ongoing. ICP could examine installing and will likely need to install a number of larger utility scale solar projects such as the one described to meet its RPS requirements.

Greenhouse Gas Impacts

The fifth consequence of forming ICP is environmental benefits. The amount of renewable power in SCE's power supply portfolio is currently 28 percent[4] and is scheduled to increase to 33 percent by 2020. Assuming ICP achieves a base case 50 percent RPS target at start-up, GHG emissions reductions attributable to ICP operations in 2019 will range from 1.33 to 2.34 million metric tons CO_2 equivalent (CO_2e) per year. ES-6 details these reductions.

[2] The Indirect effect describes the business-to-business transactions resulting from the direct effect outcomes. For example, the creation of ICP would directly create 388 additional jobs, and indirectly 60 jobs to support those 388 direct employees through increased demand for products and services in the area.
[3] The Induced effect measure the effects of the changes in household income. For example, ICP will save all households and businesses in its service area on energy costs. As a result, households will have more money to spend in the local economy.
[4] http://www.cpuc.ca.gov/RPS_Homepage/

Exhibit ES-6 Baseline Comparison of GHG Reduction by ICP in 2018				
	ICP	CVAG	SANBAG	WRCOG
Forecast Renewables (50% Renewables) ICP (GWH) – Phase 2	7,533	916	4,184	2,433
ICP RPS (GWH) – Phase 2	4,219	513	2,343	1,362
Additional Green Power	3,315	403	1,841	1,070
CO2 reduction – Low (Million Metric tons CO_2e)	1.33	0.16	0.74	0.43
CO2 reduction – High (Million Metric tons CO_2e)	2.34	0.28	1.30	0.76

The reduction in GHG emissions associated with ICP operations is significant. This amount of reduced emissions represents a reduction in the emissions from the in-State electric generation resources of 2.6 to 4.6 percent.

Summary

This Plan concludes that the formation of ICP in the service areas of CVAG, SANBAG and WRCOG is financially prudent and will yield considerable benefits for ICP's residents and businesses. These benefits include at least a 3.8 percent lower rate for electricity (assuming the 50 percent renewable scenario) than is charged by SCE while receiving nearly twice the amount of renewable energy. Rate savings increase once the ICP is fully operational to 4.5 percent. With the achievement of Phase 2 level of operations, ICP will reduce GHG emissions by as much as 2.34 million metric tons of CO_2e per year, add over 500 jobs, generate over $54 million in additional GDP, and give residents and businesses local control over their power supply and energy efficiency/distributed energy resource programs. Even with these stated rate savings, significant funds are still generated to support new programs, local DER and/or additional rate savings to the CCA's customers.

There are risks associated with a CCA which are manageable. On balance, the formation of a CCA for CVAG, SANBAG and WRCOG is financially feasible and results in beneficial environmental/economic impacts. A joint CCA with common back office functions and local branding as opposed to three separate CCAs is the most economical operational option and is also recommended. Finally, a more "hands on" organizational structure is recommended.

Introduction

Background

California's legislature passed AB 117 in 2002 (amended in 2011 by SB 790) which allows all Cities, Counties, or groups of Cities and Counties to provide electric service to customers currently served by Investor-Owned Utilities (IOUs). Community Choice Aggregation (CCA) is the legislative organization empowered to provide this service. California CCAs are customer opt-out programs that provide power supply, data management and behind the meter services, while the incumbent IOUs continue to provide transmission and distribution (wires) service. This legislation states that CCAs will enable California to experience more competitive electricity rates, a more renewable power supply mix, and growth in local resources and associated economic activity. Currently, there are five CCAs operating in California and these utilities offer competitive rates for power supply that have a higher percentage of renewable resources. CCAs have also proven to promote local economic activity and their associated benefits. Several other California Cities and Counties are currently evaluating the feasibility of CCA formation within their jurisdictions. This information can be found in Appendix A.

There are several potential benefits of the CCA model in addition to competitive rates. Other benefits include local control over energy resources selection including renewable local projects, energy efficiency, a reduction in greenhouse gases (GHG), and more economic development. In addition, CCAs can minimize power supply rates and maximize renewable energy utilization with the attendant local jobs in the local community.

Business Plan Goal

The goal of the Business Plan (Plan) is to use conservative assumptions and analysis to show the feasibility of establishing a CCA in the geographical region(s) and to build the framework for the completion of an Implementation Plan that would need to be submitted to the CPUC by the governance structure. Conservation assumptions are used throughout the Plan to ensure prudent decisions are made by the affected policymakers.

Objective

This (Plan) evaluates the feasibility of forming a CCA within the SCE service area of Coachella Valley Association of Governments (CVAG), San Bernardino Associated Governments (SANBAG) and Western Riverside Council of Governments (WRCOG), collectively named Inland Choice Power (ICP). The proposed CCA will continue to provide power supply, data management and behind the meter services[5], and Southern California Edison (SCE) will provide transmission and distribution (wires) services. This Plan estimates ICP's power supply costs, administrative costs,

[5] For example, energy efficiency programs, net energy metering or other programs that promote the deployment of distributed energy resources.

electric loads, and future retail rates for ICP and the incumbent Investor-Owned Utility (IOU), Southern California Edison (SCE). These forecast rates are compared to determine if the proposed CCA can offer competitive rates, better products, and superior customer service. A sound financial and operational foundation for ICP must be achievable before the other desirable attributes of a CCA can be enjoyed.

Regarding the possible membership of ICP, CVAG is the regional planning agency coordinating government services in the Coachella Valley and has 10 Cities, Riverside County, the Agua Caliente Band of Cahuilla Indians and the Cabazon Band of Mission Indians as members. SANBAG is the council of government and transportation planning agency for San Bernardino County. SANBAG's members include 24 cities and San Bernardino County. WRCOG's purpose is to unify Western Riverside County so that it can speak with a collective voice on important issues that affect its members and it consists of 17 Cities, Riverside County Board of Supervisors, the Eastern and Western Municipal Water Districts, and the Morongo Band of Mission Indians. Combined, these three organizations are referred to in this Plan as ICP.

Governance Structures

Two governance scenarios (individual jurisdictional and joint powers authority models) are explored in this Plan. This provides information to each of the three COGs on the benefits and costs of implementing a CCA in their individual service area. It also provides information about the benefit and cost of different sizes of CCA load. For the base case in this Plan, results are provided assuming one organization will provide all back office functions (power supply and data management) for all three entities. This scenario is referred to as the "ICP" scenario. In addition, results will be provided assuming three separate CCA's will be implemented, which would enable greater local branding and program optionality. This scenario is referred to as the "Three CCA" scenario.

ICP Description

In 2015, before opt-outs, CVAG's average annual wholesale load is 288 aMW (average Megawatts) with a peak load of 697 MW. SANBAG's 2015 average annual wholesale load, before opt-outs, is 1,339 aMW with a peak demand of 2,950 MW, while WRCOG's 2015 average wholesale annual load before opt-outs is 765 aMW with a peak demand of 1,819 MW. Energy consumption for the entire ICP area served by SCE is equal to more than 30 percent of SCE's total retail load.

For this Plan, it is assumed that service will be offered to customers in two phases. Phase 1 assumes that municipal facilities within each COG in addition to 5 percent of each COG's commercial accounts will be included into ICP. While Phase 2 assumes all customers within ICP's service area, including unincorporated Riverside County, are included in ICP, Appendix C provides the results for ICP if the unincorporated areas within the County of Riverside are not included in the analysis. Exhibit 1 summarizes this phased approach to starting ICP and the amount of load attendant with each phase.

Exhibit 1 CCA Load, Customers, and Revenue by Phase in 2017*						
Phase	**Assumed Start**	**Eligibility**	**Customer Accounts**	**Peak Load*** (MW)**	**Average Load*** (aMW)**	**ICP Annual Revenues (50% RPS)**
ICP						
Phase 1**	July, 2017	Municipal + 5% Commercial	69,669	73	49	$24 million
Phase 2	January 2018	All Customers	961,139	3,951	1,720	$963 Million
CVAG						
Phase 1**	July, 2017	Municipal + 5% Commercial	10,116	7	6	$3.2 Million
Phase 2	January 2018	All Customers	108,594	517	209	$125 Million
SANBAG						
Phase 1**	July, 2017	Municipal + 5% Commercial	41,208	44	29	$13.8 Million
Phase 2	January 2018	All Customers	517,717	2,126	955	$535 Million
WRCOG						
Phase 1**	July, 2017	Municipal + 5% Commercial	18,346	22	14	$7.0 Million
Phase 2	January 2018	All Customers	334,828	1,343	555	$321 Million

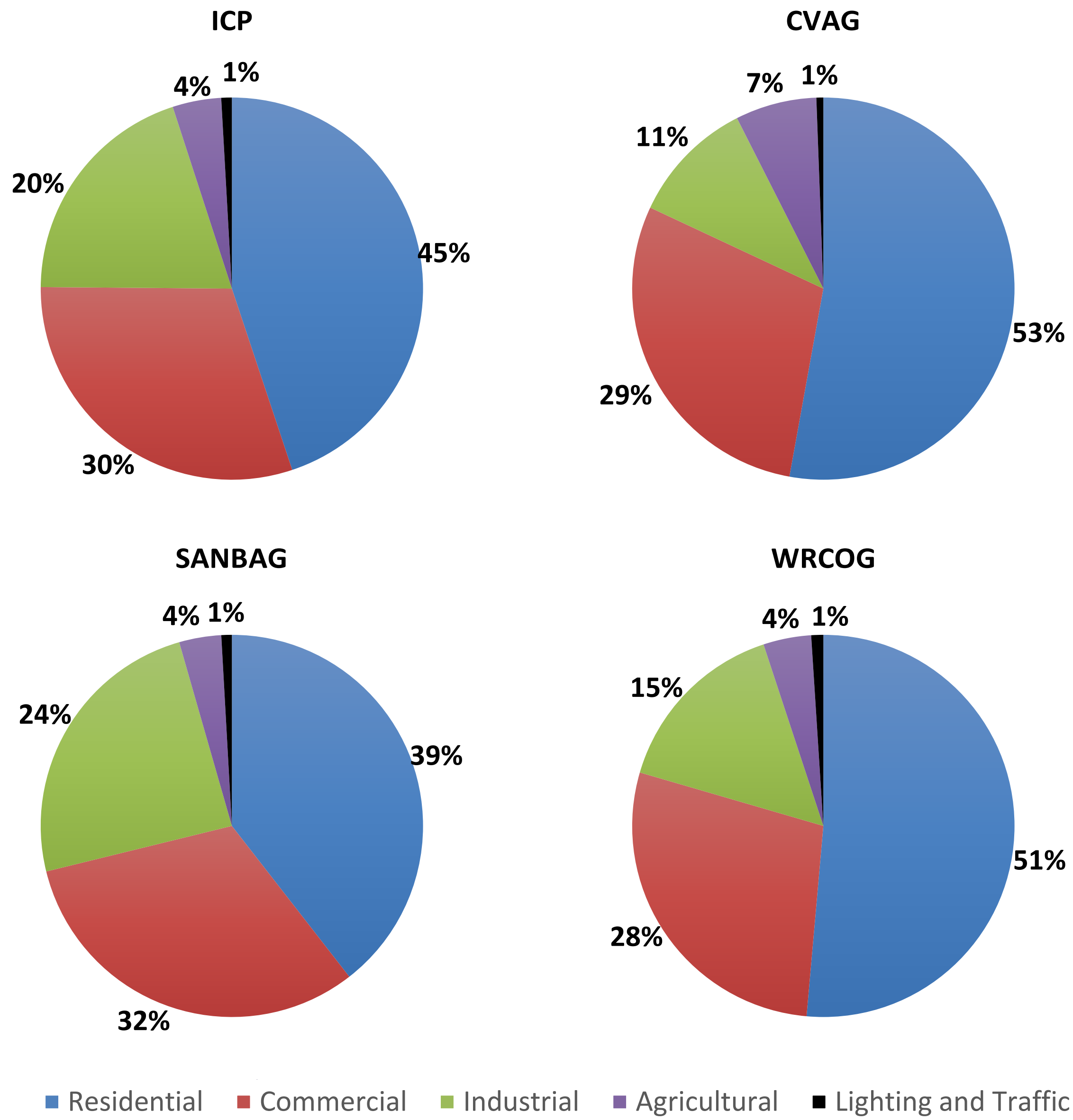
*Estimates assume a 75% participation rate for residential customers, and a 65% participation rate for non-residential customers.
**Phase 1 is assumed to run July – December of 2017. Therefore, load and revenue for this phase is estimated annual.
***Loads are expressed as wholesale, including losses of 6%.

Customer Participation Schedule

Because of the number of cities in ICP and the size of their associated loads, a phasing strategy is assumed for this Plan. This phasing strategy enables ICP to address any start-up and operational issues before full scale operations are undertaken. In addition, this strategy will allow ICP's outside party electricity suppliers, scheduling agents and data managers to ramp up their activities.

By 2036, ICP is projected to serve almost 1.16 million retail customers after opt-outs with annual electricity sales potential of over 17,392 GWh. Annual ICP revenues at Phase 2 build-out are projected to be $1.5 billion. In the same period, CVAG will serve over 132,000 customers with an average annual load of 2,110 GWh and revenues of $300 million. SANBAG will serve over 633,000 customers, a load of 9,677 GWh, and earn revenues of $550 million. WRCOG will serve almost 410,000 customers, a load of 5,605 GWh per year, and $330 million. The breakdown of projected sales in Phase 2 by major customer class is shown in the following Exhibit 2.

Exhibit 2
Retail Energy Share by Rate Class



Summary of ICP's Proposed Governance and Operations Options

ICP will likely be established under the terms of a Joint Powers Authority (JPA) versus an individual jurisdictional model, because of the inclusion of multiple jurisdictions into the CCA, which will promote, develop and conduct electricity-related projects and programs for ICP's residences and businesses. The JPA agreement will dictate the operational provisions of ICP.

ICP activities will be overseen by the new JPA's Board of Directors (Board). This Board will have primary responsibility for managing all aspects of ICP programs and providing policy guidance, which includes determining whether or not the ICP will be operated in-house with staff, minimal staff with outside consultants assisting, or hiring one third party entity to perform all of the operational mechanics.

CCA operations can be fulfilled by internal staff, external consultants, or a mix thereof. The choice of how to allocate these functions along the continuum between full internal staff and minimal internal staff will be at the discretion of the Board of the CCA. ICP operations will be the responsibility of an Executive Director, appointed by ICP's Board. The Executive Director will manage whatever combination of staff and contractors are deemed most cost-effective in accordance with the general policies established by the Board.

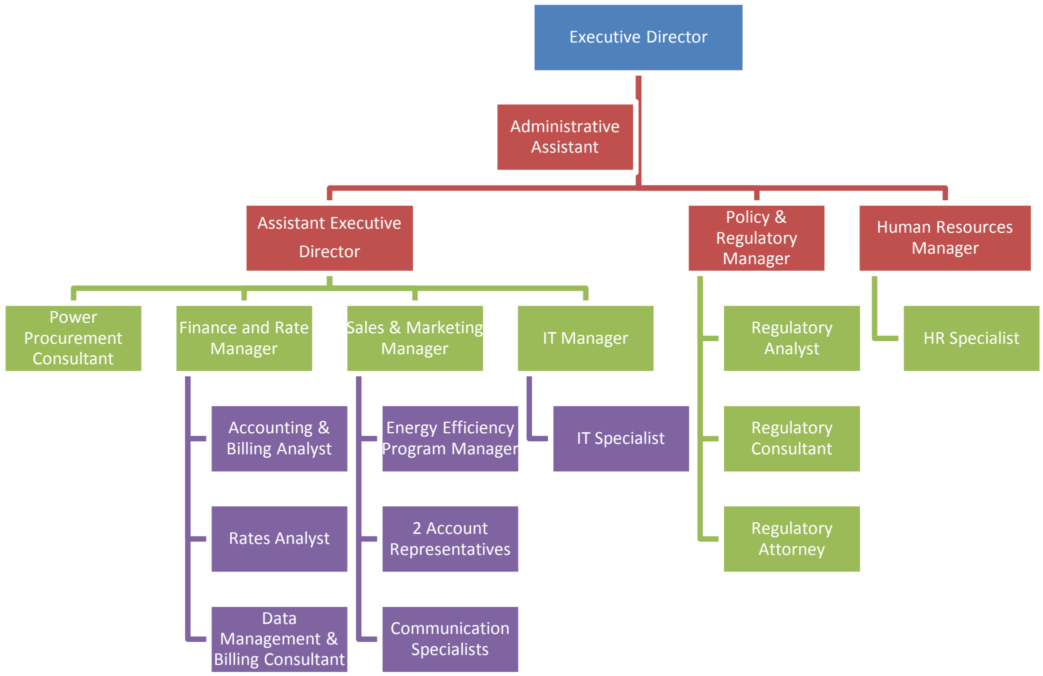
ICP has three options for staffing after the initial start-up:

1. The first option involves hiring internal staff incrementally to match workloads involved in forming ICP, managing contracts, and initiating customer outreach/marketing during the pre-operations period (Full Staff Scenario). If ICP decides to follow a "Full Staff Scenario", ICP will likely need a full time staff of approximately 15 – 20 employees to perform its responsibilities, primarily related to program and contract management, legal and regulatory, finance and accounting, energy efficiency, marketing and customer service. A sample organizational chart for this scenario is provided in Exhibit 3. Even under the Full Staff Scenario, highly technical functions associated with managing and scheduling power suppliers, retail customer billings, and data management will likely be performed by experienced outside consultants.

2. In option two, the CCA would hire just a few staff internally (i.e., Executive Director and two support staff). All remaining work would be managed through consultants (Minimum Staff Scenario). The costs of a Fully Staffed CCA versus a CCA staffed mostly by consultants are estimated to be roughly equal.

3. In the third option, ICP could contract with one or more third-parties to complete all the operational aspects of the CCA.

Exhibit 3
Sample Organization Chart



In order to develop a conservative financial proforma analysis, this Plan estimates operating costs assuming a Full Staff scenario. This is to prove that the CCA is both feasible and viable. The known staffing costs for a CCA are based on staffing the entire organization internally (excluding power supply agents and data management). It is more difficult to estimate the cost of consultants providing all services other than data management and power supply given that all existing CCAs have transitioned to internal staffing fairly quickly. As such, this Plan used the internal staffing option in the cost analysis. However, it is expected that the Board would go out to tender for consulting services and compare the cost-effectiveness of relying on consulting services versus staffing the CCA internally. Any further cost reductions associated with alternative staffing option would serve to make the CCA-related rate savings even larger than portrayed in this Plan.

Plan Outline

This Plan evaluates the cost and resulting rates of operating ICP and compares these rates to a SCE rate forecast. This pro forma 20-year feasibility analysis models the following cost components:

- Power Supply Costs:
  - Wholesale purchase
  - Renewable purchases
  - Procurement of resource adequacy capacity
  - Other power supply and charges

- Non-Power Supply Costs:
  - Start-up costs
  - ICP staffing and administration costs
  - Consulting support
  - SCE and regulatory charges
  - Reserves
  - New Program Funding
  - Financing costs (Start-up and Working Capital)
- Pass-Through Charges from SCE:
  - Transmission and distribution charges
  - Power Cost Indifference Adjustment (PCIA) Charge
  - Franchise Fee
  - Other SCE non-bypassable charges

The information above is used to determine the retail rates for ICP. ICP rates are then compared to the SCE projected rates for ICP service area.

Plan Organization

This Plan is organized into the following main sections:

- Load Requirements
- Power Supply Strategy and Costs
- ICP Cost of Service
- Products, Services, Rates Comparison and Environmental/Economic Considerations
- Sensitivity Analysis
- Summary and Recommendations

Each section is discussed in more detail below.

Load Requirements

The viability of ICP depends to various degrees on the number of customers that participate in the CCA and the amount of energy they consume. This section of the Plan provides an overview of these projected values and the methodology used to estimate them.

Historical Consumption

SCE has provided monthly historical data on energy use (kWh), non-coincident peak load (kW), and number of accounts aggregated by rate class for both direct access (DA) and bundled customers for Cities expected to participate in ICP as well as unincorporated areas in the three associations for the 2015 calendar year. These include 7 cities in CVAG, 21 in SANBAG, 16 in WRCOG, as well as both the Riverside and San Bernardino county unincorporated areas. Collectively, CVAG, SANBAG, WRCOG, and the unincorporated counties used almost 20,000 GWh of electricity in 2015. Of this, SANBAG used 56 percent, WRCOG 32 percent, and CVAG 12 percent.

Bundled and Direct Access Customers

Bundled customers (full service) make up over 93 percent of total customer accounts across the three government associations and comprise approximately 85 percent of the total energy use. Direct access customers account for under 7 percent of customers, but use nearly 15 percent of the annual energy. Exhibits 4 and 5 summarize historic energy consumption and number of accounts for bundled and DA customers within the three COGs.

Exhibit 4
Bundled and Direct Access Customer Accounts by COG in 2015

Government Association	Bundled Accounts	DA Accounts	Bundled Accounts (% of total)	DA Accounts (% of total)
CVAG	142,715	1,299	99%	1%
SANBAG	678,524	38,236	95%	5%
WRCOG	438,019	55,235	89%	11%
Total	**1,259,258**	**89,545**	**93%**	**7%**

Exhibit 5
Bundled and Direct Access Retail Load by COG in 2015

Government Association	Bundled Load (MWh)	DA Load (MWh)	Bundled Load (% of total)	DA Load (% of total)
CVAG	2,370,751	79,197	97%	3%
SANBAG	11,085,138	2,043,264	84%	16%
WRCOG	6,312,021	1,285,402	83%	17%
Total	**19,767,910**	**3,407,864**	**85%**	**15%**

Direct access customers purchase their power supply and other services from an electric service provider (ESP), rather than the incumbent utility. In California, eligibility for DA enrollment is currently limited to retail non-residential customers and enrollment is based on an annual lottery.[6] Customers classified as taking service under direct access arrangements are not included in this Plan, as it is assumed that these customers will remain with their current ESPs.

City and Unincorporated Loads

Among bundled customers, approximately 79 percent are located within the 44 cities and account for 81 percent of annual energy usage in the three COGs as shown in Exhibit 6. Potential customers and energy consumption are shown in Exhibit 7 aggregated for each COG including the respective unincorporated load. Exhibit 8 illustrates the distribution of load by sector for each jurisdiction.

Exhibit 6
Bundled Load and Accounts by Jurisdiction Type in 2015

Jurisdiction	Customer Accounts	Customer Accounts (% of total)	Annual Wholesale Load (GWh)	Energy Use (% of total)
Cities	994,814	79%	16,975	81%
Unincorporated Riverside and San Bernardino Counties	264,444	21%	3,982	19%
Total	**1,259,258**	**100%**	**20,957**	**100%**

It should be noted that the County's unincorporated load has been included in these total usage amounts.

[6] S.B. 286 (CA, 2015-2016 Reg. Sess.)

Exhibit 7
Bundled Load and Accounts by Sector and COG

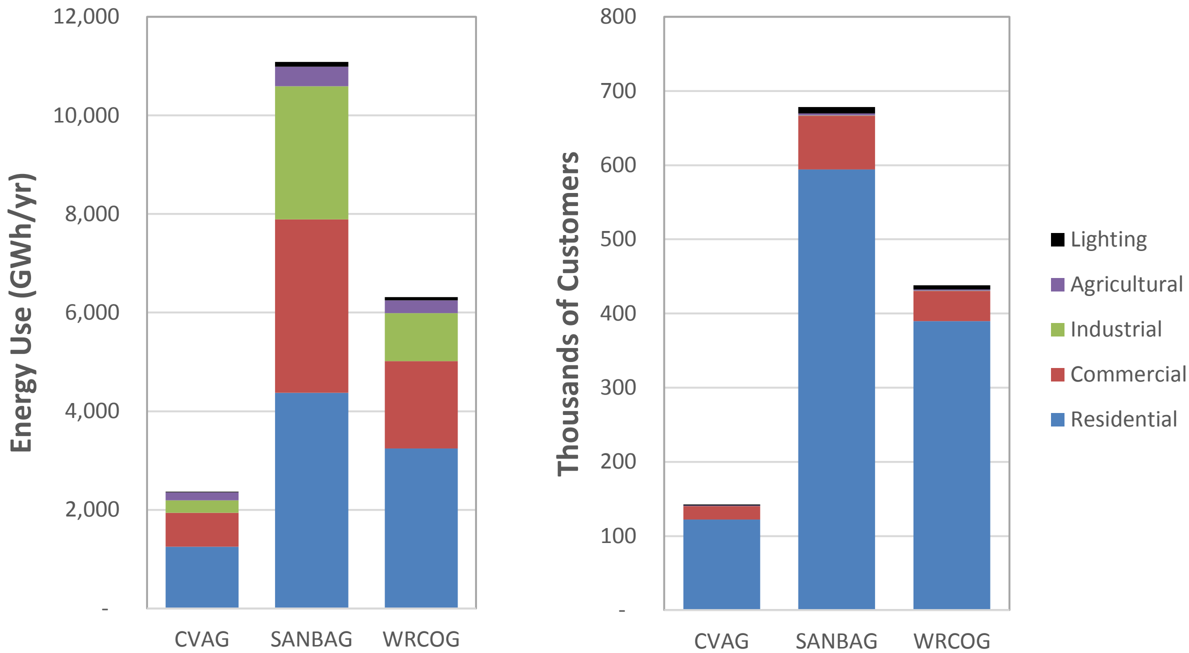
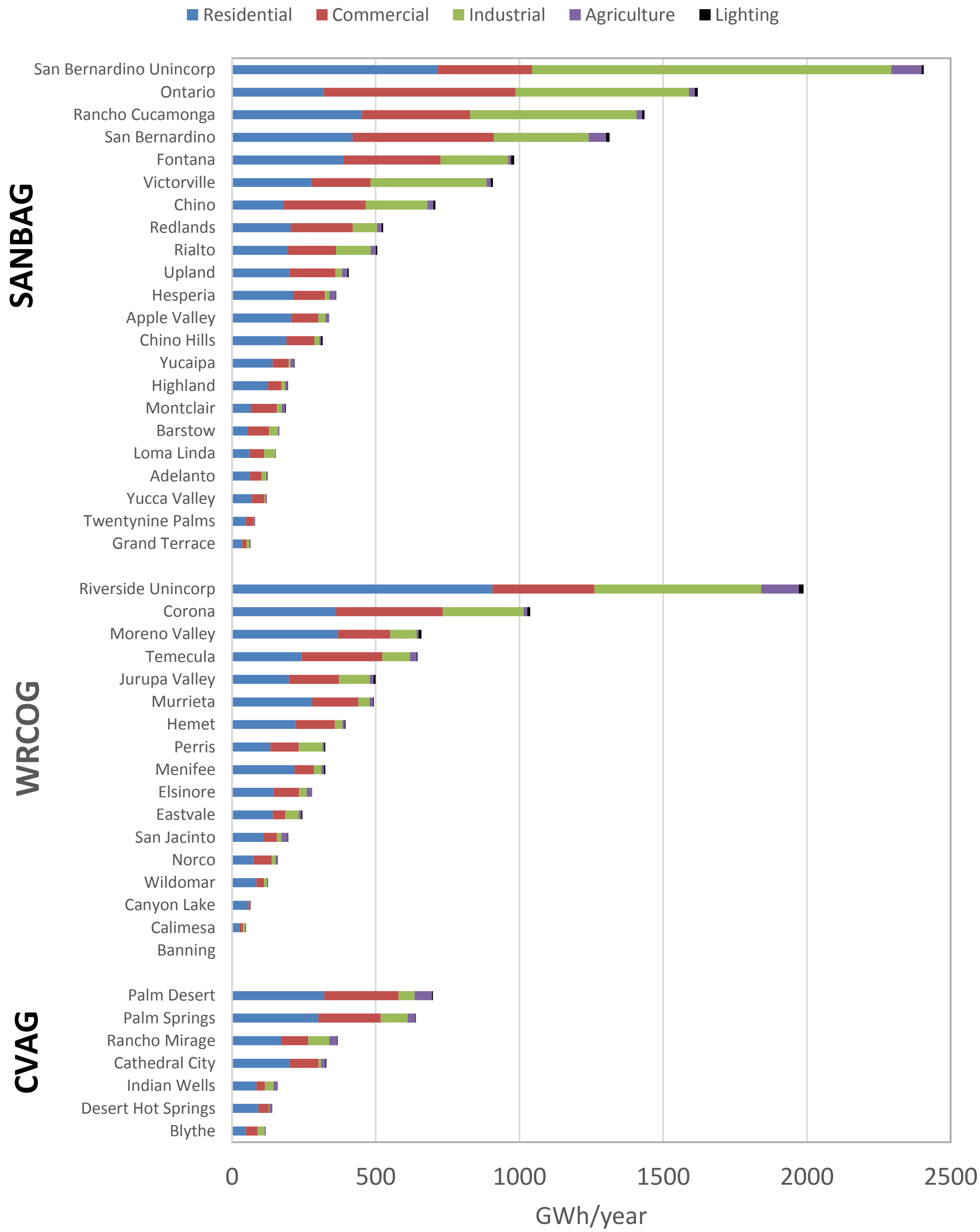


Exhibit 8
Bundled Energy Use by Jurisdiction and Sector



Note: Riverside County unincorporated areas were split up between WRCOG and CVAG for the 3-CCA scenarios, but are represented as a single entity in this figure for comparison.

ICP Launch Phases

For the purpose of this Plan, it has been assumed that the development of ICP will occur using a two-phase implementation schedule. Phase 1 will include all municipal facilities as well as 5 percent of private commercial accounts within the three COGs. Phase 1 includes the 5 percent non-municipal accounts to balance out the daily load profile of the municipal accounts, which on their own would not be representative of ICP as a whole. These non-municipal accounts will be recruited for participation in Phase 1 during the start-up of ICP. Phase 2 will enroll all remaining customers in the three COGs.

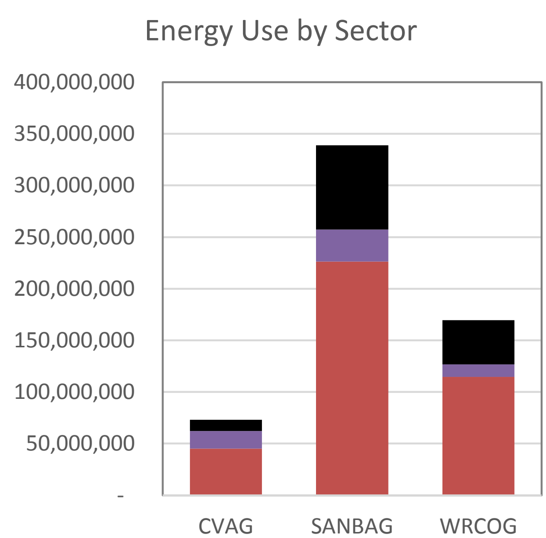
Municipal facility energy use and number of accounts was provided by CVAG, SANBAG, and WRCOG. That data, in combination with 5 percent of non-municipal commercial accounts, is summarized in Exhibit 9. This data provides the basis for Phase 1 of ICP's Implementation Plan. Exhibit 10 shows the total number of eligible municipal facilities in the three COGs and their consumption.

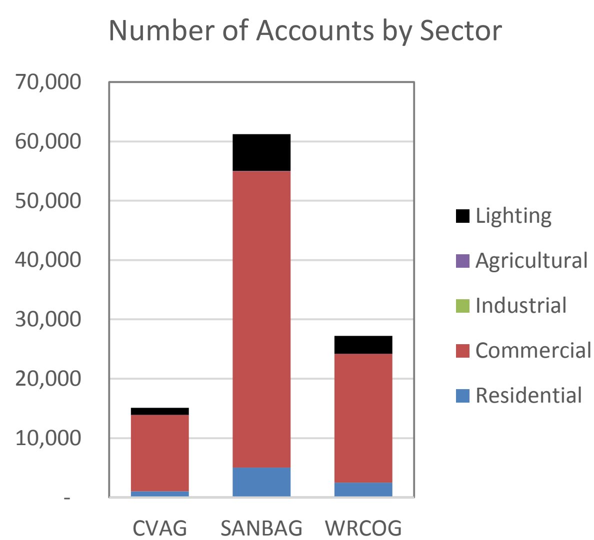
Exhibit 9
Phase 1 Accounts and Load, July 2017

Location	Customer Accounts	Customer Accounts (% of total)	Annual Wholesale Load (MWh)	Load (% of total)
CVAG	10,121	15%	51,678	13%
SANBAG	41,207	59%	239,845	58%
WRCOG	18,339	26%	119,963	29%
Total	**69,667**	**100%**	**411,486**	**100%**

Exhibit 10 shows energy consumption and customer distribution by sector for Phase 1 facilities.

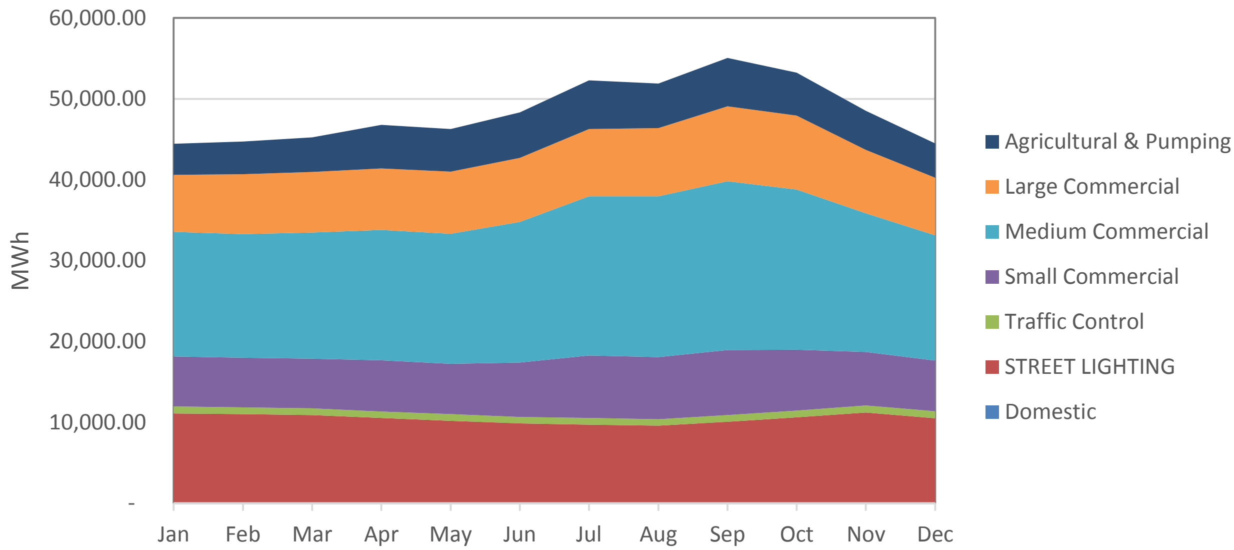
Exhibit 10
Phase 1 Load Data by Rate Schedule





The monthly energy distribution of Phase 1 customers is illustrated in Exhibit 11.

Exhibit 11
Monthly Energy Use by Rate Class for Total County Facilities



ICP Customer Participation Rates

Customers will receive a total of four notices of ICP's service to give them an opportunity to opt-out. The first two notices will be issued before customers are served by ICP at 60 and 30 days before ICP's launch. These notices will provide information needed to understand the terms and conditions of service from ICP and explain how customers can opt-out, if desired. Subsequent to commencement of service, customers will be given two additional opportunities to opt-out and return to SCE at 30 and 60 days after ICP's launch. Customers that opt-out between the initial switchover date and the close of the post enrollment opt-out period will be responsible for ICP usage-related charges for the time they are served by ICP but will not otherwise be subject to any charges for leaving ICP. All customers that do not follow the opt-out process specified in the customer notices will be automatically enrolled into ICP. Customers automatically enrolled will continue to have their electric meters read and billed for electric service by SCE. ICP bills processed by SCE will show separate charges for power supply procured by ICP, all other charges related to delivery of the electricity by SCE and other utility charges that will continue to be assessed.

This Plan anticipates an overall customer participation rate of 100 percent during Phase 1, as service is being offered to municipal facilities and selectively recruited private commercial customers. For Phase 2, it is assumed that approximately 75 percent of residential customers and 65 percent of non-residential customers will remain with ICP. These opt-out assumptions are conservative estimates when compared to participation rates in other CCAs. For operating CCAs in California, at least 85 percent of the potential customers have stayed with the CCA.

Forecast Consumption and Customers

Going forward, projections for customers enrolled in ICP and retail energy consumption have been forecast to increase at 1.13 percent per year. This forecast is based on the mid-case electricity demand forecasts for the SCE planning area, as reported to the California Energy Commission (CEC).[7] Hourly electric consumption and peak demands have been estimated based on SCE's hourly load profiles for each customer classification.

The forecast of load served by ICP over the next 20 years is shown in Exhibit 12. This exhibit reflects an estimated annual growth of 1.13 percent. The ICP forecast of kWh sales reflects the roll-out and customer enrollment schedule shown above. Annual energy requirements are shown below in Exhibit 13.

Exhibit 12
Projected Load by Sector

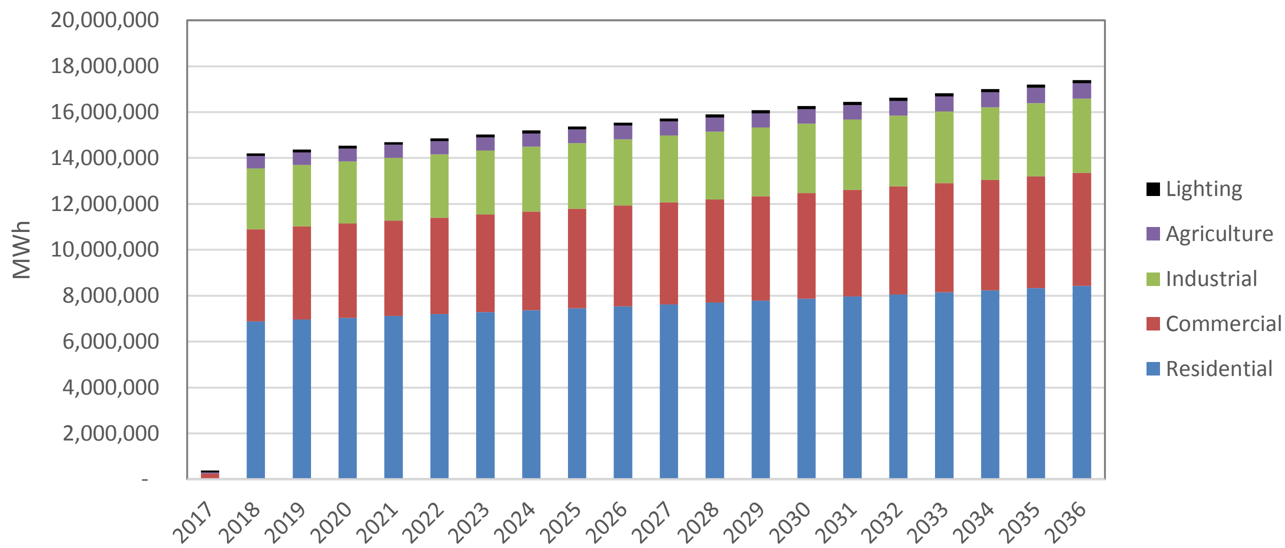


Exhibit 13
ICP Projected Annual Energy Requirements

	2017	2018	2019	2020	2021	2022	2023	2024	2025
Retail Sales (MWh)	386,383	14,207,376	14,367,920	14,530,277	14,694,469	14,860,517	15,028,441	15,198,262	15,370,003
Losses (MWh)	25,103	858,741	868,445	878,258	888,183	898,219	908,369	918,634	929,014
Total Load Requirements (MWh)	411,486	15,066,118	15,236,365	15,408,536	15,582,652	15,758,736	15,936,810	16,116,896	16,299,017
Max Demand (MW)	434	14,208	14,368	14,531	14,695	14,861	15,029	15,199	15,370

[7] Southern California Edison. *California Energy Demand Forecast, 2015-2025.* July 2015. Sacramento, CA: California Energy Commission.

Renewable Resource Requirement

In addition to estimating the potential retail loads and customers, current legislation requires that a certain percent of annual retail electric sales be supplied from qualified renewable energy resources.

SBX1 2 passed in April, 2011 established a 33 percent Renewable Portfolio Standard (RPS) requirement by 2020 with certain procurement targets prior to 2020. SBX1 2 also defined three types of renewable categories (or Buckets) that can be used to meet the RPS target.

Bucket 1 – Renewable resources located in California or out-of-state renewable resources that can meet strict scheduling requirement ensuring deliverability into California. According to SBX1 2 there are no limits on Bucket 1 renewable resources.

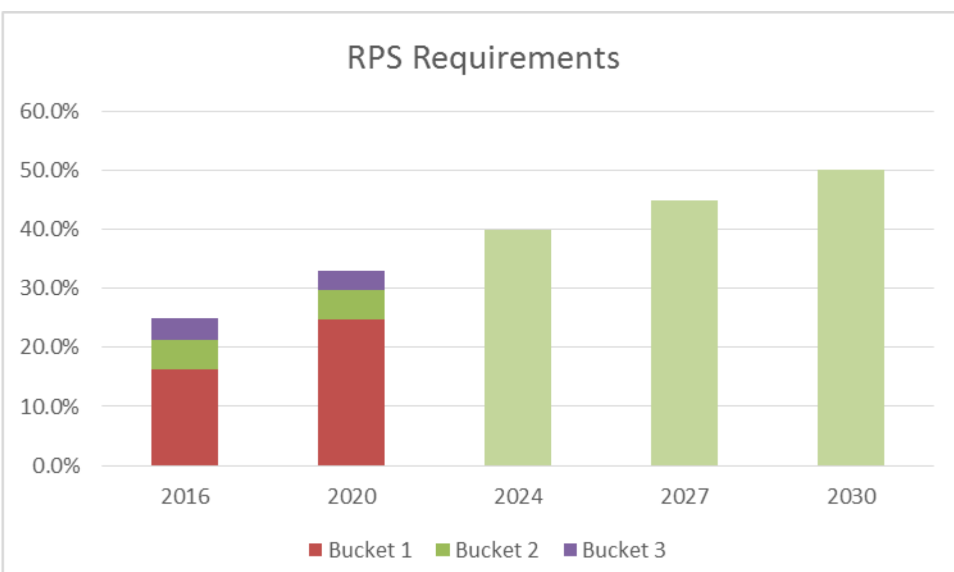
Bucket 2 – Bucket 2 renewable resources are firmed or shaped renewable resources not necessarily delivered to California, but an equivalent amount of energy is delivered from a different non-renewable resource and then bundled with Renewable Energy Certificates (RECs). Bucket 2 resources are limited to annual maximum of 20 percent of total RPS procurement through 2016 and 15 percent through 2020.

Bucket 3 – Bucket 3 consists of unbundled Renewable Energy Certificates which are separated from the actual electric energy. Bucket 3 resources are limited to an annual maximum of 15 percent of total RPS procurement through 2016 and 10 percent through 2020.

In addition, SB350 increased the RPS requirement to 50 percent by 2030. At this time, the amount of REC's that can be used to meet the 50 percent RPS requirement has not been finalized.

Exhibit 14 provides an overview of the RPS requirements until 2030.

Exhibit 14
California RPS Requirements as a Percent of Total Power Supply



ICP's Plan has been developed assuming ICP will meet a 50 percent RPS target as soon as possible through renewable and non-renewable contracts, distributed generation and local resources.

ICP will exceed SCE's renewable energy percentage from the first day of its operations when it meets its 50 percent goal. ICP will therefore significantly exceed the minimum RPS requirements and significantly exceed the renewable power share provided by SCE.

Resource Adequacy Requirements

In addition to determining the renewable resource requirement, ICP will also need to demonstrate and report that it has sufficient physical power supply capacity to meet its projected peak demand plus a 15 percent planning reserve margin. This requirement is in accordance with resource adequacy regulation administered by the CPUC and the California Energy Commission (CEC).

The CPUC's resource adequacy standards applicable to ICP require a demonstration one year in advance that ICP has secured physical capacity for 90 percent of its projected peak demand for each of the five months May through September, plus a minimum 15 percent reserve margin. On a month-ahead basis, ICP must demonstrate 100 percent of the peak load plus a minimum 15 percent reserve margin.

The Plan's load forecast estimates capacity needs, including resource capacity requirements, to be used for the power supply cost forecasting.

Power Supply Strategy and Costs

This section of the Plan provides a discussion of the power supply resource cost forecasts, potential power supply strategies that could be implemented by ICP and provides power supply portfolio pricing based on the loads projected for ICP.

ICP will be charged with developing both short (one and two-year) and long-term (five to twenty years) resource plans. ICP will develop the resource plan under the guidance provided by its Joint Power Authority (JPA), in compliance with California law, and other requirements of California regulatory bodies (CPUC and CEC).

Long-term resource planning includes load forecasting and supply planning. ICP's planners will develop Integrated Resource Plans (IRPs) that meet their supply objectives and balance cost, risk, and environmental considerations. Integrated resource planning considers demand side energy efficiency and demand response programs as well as traditional supply options. ICP will require a planning function even if the day-to-day supply operations are contracted to third parties. This will ensure that local preferences regarding the future composition of supply and demand resources are planned for, developed and implemented.

Resource Strategy

ICP may want to seek to maximize the use of local, cost-effective renewable generation resources in its IRP. The ability to invest capital in power supply and demand-side resources using tax-exempt financing is an important factor in ICP's ability to increase the use of renewable energy while offering rates that are competitive with SCE. Power purchases from renewable and non-renewable resources will supply the remaining majority of the resource mix. ICP's power supply portfolio will be managed by a third party electric supplier, at least during the initial implementation period. Through a power services agreement, the Plan assumes that ICP will obtain full service requirements electricity for its customers, including providing for all electric, ancillary services and the scheduling arrangements necessary to provide delivered electricity.

Resource Costs

For this Plan, individual resource costs are estimated and other energy providers based on current market condition, recent power supply contracts for renewable energy as well as a review of the applicable regulatory requirements.

Market Purchases

Natural gas-fired power plants are typically the marginal power supply resource that sets the electricity market price in southern California and elsewhere in the Western Energy Coordinating Council (WECC) footprint. WECC generally guides power supply resources west of the Rocky Mountains. As the market price of electricity is usually set by the cost of the marginal unit, a wholesale market price forecast has been developed using a forecast of natural gas prices and the projected relationship between gas prices and electricity prices (also defined as market-implied heat rates or spark spreads). The projected market-implied heat rates reflect the average efficiency of gas-fired power plants in California. Projected heat rates are based on historic market-implied heat rates which are calculated by dividing historic southern California (SP15) wholesale market prices by historic southern California natural gas prices. A natural gas price forecast has been developed based on NYMEX forward gas prices for the Henry Hub trading hub and southern California basis differentials. Projected market heat rates have then been applied to the southern California natural gas price forecast to calculate a wholesale electric market price forecast for southern California.

The following steps have been taken to produce the wholesale electric market price forecast:

1. Forward prices for natural gas at Henry Hub are available through June 2025.
2. The southern California basis differential is used to adjust the Henry Hub forward prices to southern California prices. Southern California forward natural gas prices are equal to NYMEX forward prices (Henry Hub) plus the southern California basis. The southern California basis forward curve is available through December 2020. After December 2020, the monthly southern California basis is assumed to increase at 5 percent.
3. Projected monthly market-implied heat rates are multiplied by forecast southern California natural gas prices to calculate forecast southern California wholesale market prices.
4. Projected heat rates are based on historic heat rates (southern California wholesale electricity prices divided by SoCal natural gas prices).
5. Monthly market-implied heat rates are held constant in all years.
6. Forecast southern California wholesale electric market prices are escalated by a 3.5 percent annual growth rate after June 2025.
7. Forecast southern California wholesale electric market prices are benchmarked against other market price forecasts.

Based on the methodology detailed above, southern California wholesale market prices are projected to escalate annually at an average rate of 3.7 percent over 2017 through 2036.

Exhibit 15 shows the forecast southern California natural gas prices.

Exhibit 15
Forecast SoCal Natural Gas Price ($/MMBtu)

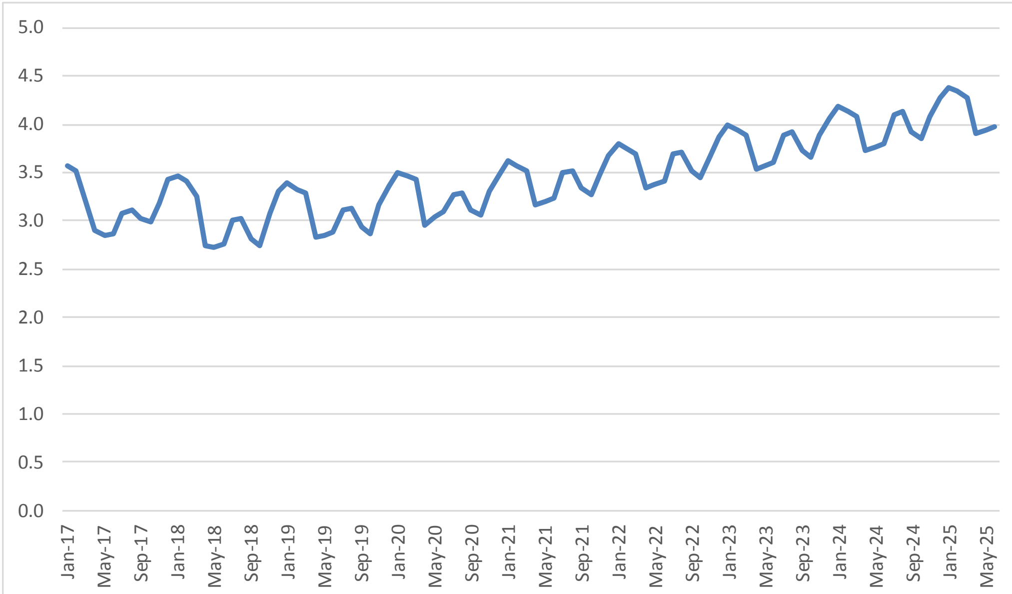
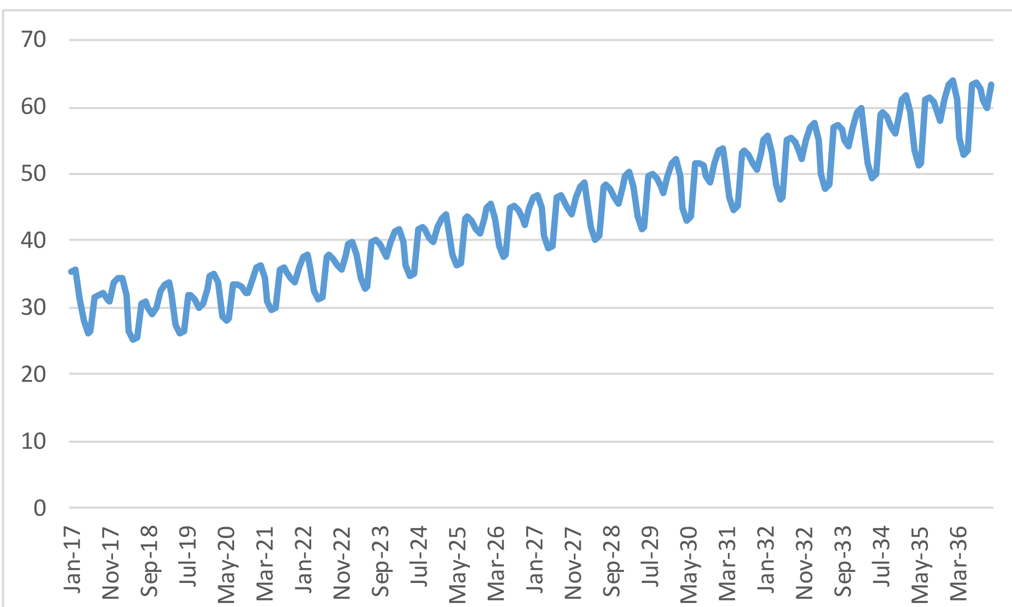


Exhibit 16 shows the resulting monthly southern California wholesale electric market price forecast. The levelized value of market prices over the study period is $41.6/MWh (2016$).

Exhibit 16
Forecast Southern California Wholesale Market Prices ($/MWh)



Wholesale power prices have been used to calculate balancing market purchases and sales. When ICP's loads are greater than its resource capabilities, ICP's scheduling agent will schedule balancing purchases and ICP will incur balancing market purchase costs. When ICP's loads are less than its resource capabilities, ICP's scheduling agent will transact balancing sales and ICP will receive market sales revenue. Balancing market purchases and sales can be transacted on a monthly, daily and hourly pre-schedule basis.

Renewable Energy

The wholesale market prices shown above are for "non-renewable" power (i.e., this product does not come with any renewable energy credit (REC) attributes). The cost of renewable resources varies greatly. Wind and solar levelized project costs vary from $35 to $60/MWh. Geothermal project costs can vary from $70 to $100/MWh. The availability of off-shore wind and ocean power in the marketplace is fairly minimal and, as such, these resources were not included in the assessment of renewable energy market prices.

Based on a survey of renewable resources currently in operation and new projects coming on-line, a base case renewable energy market price of $42/MWh has been determined. Renewable energy prices may increase in the future as the demand for renewable energy increases due to California's RPS and the possible expiration of the solar investment tax credit. However, renewable prices are being driven down by solar project costs which have declined sharply over the past few years and are expected to continue to decrease over the next 10 to 20 years. Again, the renewable energy prices have been independently confirmed by current market tenders in southern California.

Projected power costs in this Plan are calculated using the base case renewable energy market price of $42/MWh. The amount of renewable energy purchased will be assumed to be equal to the RPS requirements in the base case. A higher case of 50 and 100 percent renewable energy will also be considered later in this Plan. In the "100 percent renewables" case the renewable energy market price was increased to $52/MWh. The $42/MWh price was based on an assumption that renewable purchases would be served almost exclusively with the output from solar projects. In the "100 percent renewables" case a higher price was assumed in recognition that a more diverse, and therefore more expensive, renewable energy portfolio would be needed. As such, the $52/MWh is a blend of projected solar, geothermal and wind project costs. This is a conservative assumption as current solar contracts have a market value of $35 - $40/MWh.

Renewable Energy Credits (RECs)

As noted earlier, California load serving entities must purchase renewable energy or attributes that meet certain eligibility requirements across three categories or buckets. Each of the buckets represents a different type of renewable energy and can be used to meet a specific percent of the total. The shares of each bucket also changes over time. The three buckets and the type of energy included in each bucket can be summarized as follows:

- Bucket 1: In-state renewable generation
- Bucket 2: Firmed and shaped renewable energy products from a generator that has its first point of interconnection with a California Balancing Authority (such as the CAISO)
- Bucket 3: Energy is not included with the RECs (also known as unbundled RECs)

Under the current guidelines, the amount of RECs procured through Buckets 2 and 3 is limited and decreases over time. Historically, the first bucket has been the most expensive type of energy to purchase and load serving entities were only procuring the minimum they need to meet the RPS requirement. However, with the decrease in solar project costs, Bucket 1 has become relatively less expensive (compared to Buckets 2 and 3).

RECs are not generally viewed as good for the development of new local renewable projects. In addition, the REC market is not as liquid as it once was. For the Plan's base case, unbundled REC prices are assumed to increase from \$10/REC in 2017 to \$20 in 2036 (3.7 percent annual escalation). Due to the decline in solar project costs, the cost of unbundled RECs to meet RPS requirements and wholesale market purchases to meet load are negligible. Due to this shift in market dynamics, Bucket 3 RECs are no longer the least expensive option (as they were historically).

The Plan assumes that ICP will not rely on REC purchases to meet RPS requirements. The REC market can, however, be used to balance RPS requirements with renewable energy acquisitions. If ICP is short of RECs in a given compliance year, RECs could be purchased to meet the requirements. If the CCA is long on RECs in a given compliance year, surplus RECs could be sold.

Transmission

ICP will pay the CAISO for transmission congestion and ancillary services. Transmission congestion occurs when there is insufficient capacity to meet the demands of all transmission customers. Congestion refers to a shortage of transmission capacity to supply a waiting market, and is marked by systems running at full capacity and still being unable to serve the needs of all customers. The transmission system is not allowed to run above its rated capacities. Congestion is managed by the CAISO by charging congestion charges in the day-ahead market. Congestion charges can be managed through the use of Congestion Revenue Rights (CRR). CRRs are financial instruments made available through a CRR allocation, a CRR auction, and a secondary registration system. CRR holders manage variability in congestion costs. The CCA's congestion charges will depend on the transmission paths used to bring resources to load. As such, the location of generating resources used to serve ICP load will impact these congestion costs.

The Grid Management Charge (GMC) is the vehicle through which the CAISO recovers its administrative and capital costs from the entities that utilize the CAISO's services. ICP's Grid Management Charges are expected to near \$0.5/MWh.

The CAISO performs annual studies to identify the minimum local resource capacity required in each local area to meet established reliability criteria. Load serving entities receive a proportional allocation of the minimum required local resource capacity by transmission access charge area, and submit resource adequacy plans to show that they have procured the necessary capacity. Depending on these results of the annual studies, there may be costs associated with local capacity requirements for ICP.

Because generation is delivered as it is produced and particularly with respect to renewables can be intermittent, deliveries need to be firmed using ancillary services to meet ICP's load requirements. Ancillary services will need to be purchased from the CAISO. Regulation and operating reserves are described below.

- *Regulation Service:* Regulation service is necessary to provide for the continuous balancing of resources with load and for maintaining scheduled interconnection frequency at 60 cycles per second (60 Hertz). Regulation and frequency response service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load.

- *Operating Reserves - Spinning Reserve Service:* Spinning reserve service is needed to serve load immediately in the event of a system contingency. Spinning reserve service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service.

- *Operating Reserves – Non-Spinning Reserve Service:* Non-spinning reserve service is available within a short period of time to serve load in the event of a system contingency. Non-spinning reserve service may be provided by generating units that are on-line but not providing power, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service.

Based on a survey of ancillary service costs currently paid by CAISO participants, ICP's ancillary service costs are estimated to be near $5/MWh. The Plan's base case will assume the CCA's ancillary service costs are $5/MWh in 2017, escalating by 1.5 percent annually thereafter. Serving a greater percentage of load with renewables will likely result in increased grid congestion and higher ancillary service costs. For this reason, the ancillary service costs have been increased in the 50 percent and 100 percent renewables cases included in this Plan. For the 50 percent renewables case, ancillary service costs are assumed to be $5.5/MWh in 2017. For the 100 percent renewables case, ancillary service costs are assumed to be $8/MWh in 2017, escalating by 2.5 percent.

Power Management/Scheduling Agent

Given the likely complexity of ICP's resource portfolio, ICP will want to rely on a reputable scheduling agent to economically manage ICP's power purchases and wholesale market transactions. ICP's resource portfolio will ultimately include market purchases, shares of some relatively large power supply projects, as well as shares of smaller, most likely renewable, resources with intermittent output. Managing a diverse resource portfolio with metered loads that will be heavily influenced by distributed generation will be one of the most important functions of ICP. As such, ICP needs a dependable, established scheduling agent with a proven track record in the industry. ICP's scheduling agent will be one of its most important business partners.

ICP should initially contract with a third party with the necessary experience (and balance sheet) to perform most of ICP's portfolio operation requirements. This will include the procurement of energy and ancillary services, scheduling coordinator services, and day-ahead and real-time trading. Portfolio operations encompass the activities necessary for wholesale procurement of electricity to serve end use customers. These activities include the following:

- *Electricity Procurement* – assemble a portfolio of electricity resources to supply the electric needs of ICP customers.

- *Risk Management* – standard industry risk management techniques will be employed to reduce exposure to the volatility of energy markets and insulate customer rates from sudden changes in wholesale market prices.

- *Load Forecasting* – develop accurate load forecasts, both long term for resource planning, and short-term for the electricity purchases and sales needed to maintain a balance between hourly resources and loads.

- *Scheduling Coordination* – scheduling and settling electric supply transactions with the CAISO.

ICP should approve and adopt a set of protocols that will serve as the risk management tools for ICP and any third party involved in ICP portfolio operations. Protocols will define risk management policies and procedures, and a process for ensuring compliance throughout the organization. During the initial start-up period, the chosen full requirements electric suppliers will bear the majority of risks and be responsible for their management. Development of protocols can take place during the first few months of ICP operations to cover electricity procurement activities.

A scheduling agent provides day-ahead and real-time power and transmission scheduling services. Scheduling agents bear the responsibility for accurate and timely load forecasting and resource scheduling including wholesale power purchases and sales required to maintain hourly load/resource balances. A scheduling agent needs to provide the marketing expertise and analytical tools required to optimally dispatch ICP's surplus resources on a monthly, daily and hourly basis.

Inside each hour, the CAISO Energy Imbalance Market (EIM) takes over load/resource balancing duties. The EIM automatically balances loads and resources every fifteen minutes and dispatches least-cost resources every 5-minutes. The EIM allows balancing authorities to share reserves, and more reliably and efficiently integrate renewable resources across a larger geographic region.

Within a given hour, metered energy (i.e. actual usage) may differ from supplied power due to hourly variations in resource output or unexpected load deviations. Deviations between metered energy and supplied power are accounted for by the EIM. The imbalance market is used to resolve imbalances between supply and demand. The EIM deals only with energy, not ancillary services or reserves (which are addressed in the next section).

The EIM optimally dispatches participating resources to maintain load/resource balance in real-time. The EIM uses the CAISO's real-time market which uses Security Constrained Economic Dispatch (SCED). SCED finds the lowest cost generation to serve the load taking into account operational constraints such as limits on generators or transmission facilities. The five-minute market automatically procures generation needed to meet future imbalances. The purpose of the five-minute market is to meet the very short term load forecast. Dispatch instructions are effectuated through the Automated Dispatch System (ADS).

The CAISO is the market operator, and runs and settles EIM transactions. ICP's scheduling agent will submit ICP's load and resource information to the market operator. EIM processes are running continuously for every fifteen-minute and five-minute intervals, producing dispatch instructions and prices.

Participating resource scheduling coordinators submit energy bids to let the market operator know that they are available to participate in the real-time market to help resolve energy imbalances. Resource schedulers may also submit an energy bid to declare that resources will increase or decrease generation if a certain price is struck. An energy bid is comprised of a megawatt value and a price. For every increase in megawatt level, the settlement price also increases.

The CAISO calculates financial settlements based on the difference between schedules and actual meter data, and bid prices during each hour. Locational Marginal Prices (LMP) are used in settlement calculations. The LMP is the price of a unit of energy at a particular location at a given time. LMPs are influenced by nearby generation, load level, and transmission constraints and losses.

ICP's scheduling agent will need to forecast ICP's hourly loads as well as ICP's hourly resources including shares of any hydro, wind, solar and other resources in which ICP is a participant/purchaser. Forecasting the output of hydro, wind and solar projects involves more variables than forecasting loads. Scheduling agents already have models set up to forecast accurately hourly hydro, wind and solar generation. Accurate load and resource forecasting will be a key element in assuring ICP's power supply costs are minimized.

A scheduling agent also needs to provide monthly checkout and after-the-fact reconciliation services. This requires scheduling agents to agree on the amount of energy purchased and/or sold and the purchase costs and/or sales revenue associated with each counterparty with which ICP transacted in a given month.

Based on conversations with scheduling agents currently working the CAISO footprint, the estimated cost of scheduling services is in the $1 to $2/MWh range. For the base case, the Plan has assumed a cost of $1.5/MWh, escalating at 2.5 percent annually.

Resource Portfolios

In order to develop pricing options for ICP customers and evaluate the impact of varying levels of renewable resources in ICP's portfolios, three resource portfolios were developed: RPS Portfolio, 50 percent renewable portfolio and 100 percent renewable portfolio.

Resource Options

For each of the resource portfolios, a combination of resources has been assumed in order to meet the renewable energy target, resource adequacy targets, and ancillary and balancing requirements.

Exhibit 17 shows the 20-year levelized resource costs included in this Plan.

Exhibit 17
20-Year Levelized Cost
(2016 $/MWH)

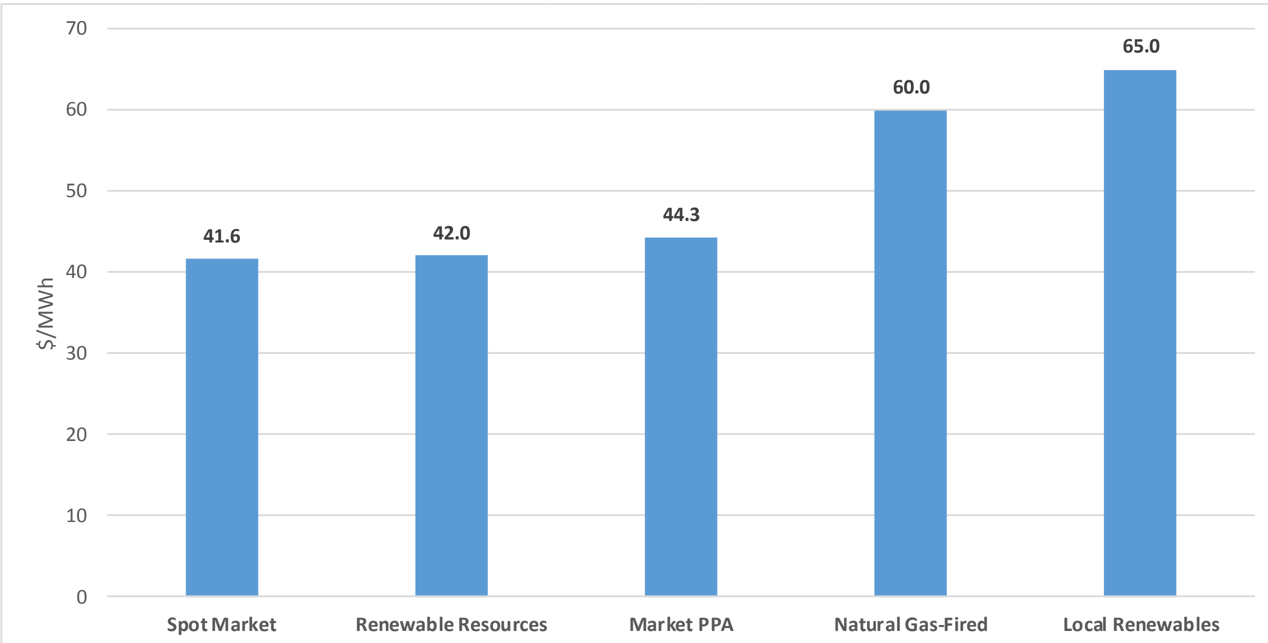


Exhibit 17 above includes both spot market and market PPA costs. It is assumed that these costs are primarily for natural gas resources although the specific resource source cannot be determined from a spot market purchase. Market PPA costs are greater than spot market costs in recognition of the cost of the PPA supplier absorbing the market price risk associated with providing a long-term PPA contract price.

The capacity factor for market PPA purchases is assumed to be 100 percent (flat monthly blocks of power). The average monthly capacity factor for renewable resources and local renewables is assumed to be 33 percent. The capacity factor for non-renewable resources is assumed to be 80 percent. As noted above, the cost of renewable resources was increased from $42/MWh to $52/MWh in the 100 percent renewables case in recognition of the need for a more diverse mix of renewable resources. Again, this higher price may be mitigated if large solar projects continue to be pursued in California.

As shown above, the base case 20-year levelized cost of renewable resources is comparable to the 20-year levelized cost of market purchases. The cost of solar projects has declined significantly over the past few years. The $42/MWh projection is based on the cost of relatively new solar projects that reflect the decreased costs, on a $/watt basis, of solar projects. The

$/watt is expected to continue to decrease in future years notwithstanding the possible expiration of the investment tax credit for renewable energy. As such, the cost of the output of solar projects is expected to continue to decrease.

On a $/watt basis, the cost of smaller scale solar projects is greater than the cost of large scale solar projects. The $65/MWh cost associated with local renewables reflects this trend. The advantage of local renewable projects is lower transmission costs and less stress on the congested transmission grid.

A more detailed description of each ICP power supply portfolio option follows.

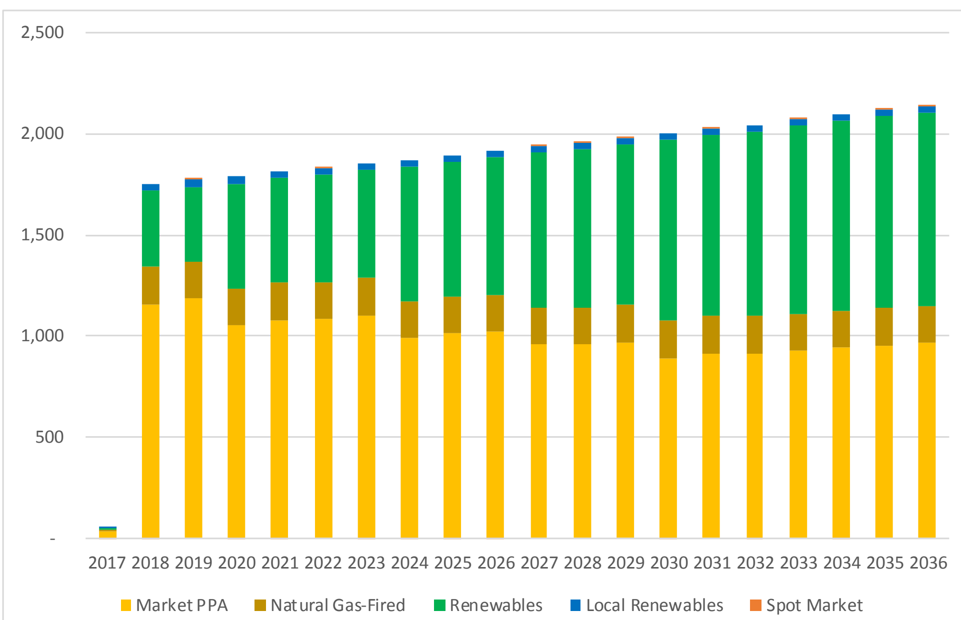
Portfolio 1: Meet Current RPS Requirements (Baseline Portfolio, similar to current SCE resource mix)

In the first portfolio, ICP will meet the State RPS requirements shown below:

- 2017-19: 25 percent
- 2020-23: 33 percent
- 2024-26: 40 percent
- 2027-29: 45 percent
- Post-2030: 50 percent

As shown above, due to the decrease in the cost of solar projects, the projected cost of renewables is comparable to the cost of market power and less than the cost of new gas-fired generation. Exhibit 18 shows the power supply portfolio used to serve load in Portfolio 1.

Exhibit 18
Portfolio 1: Meet RPS Requirements (aMW)

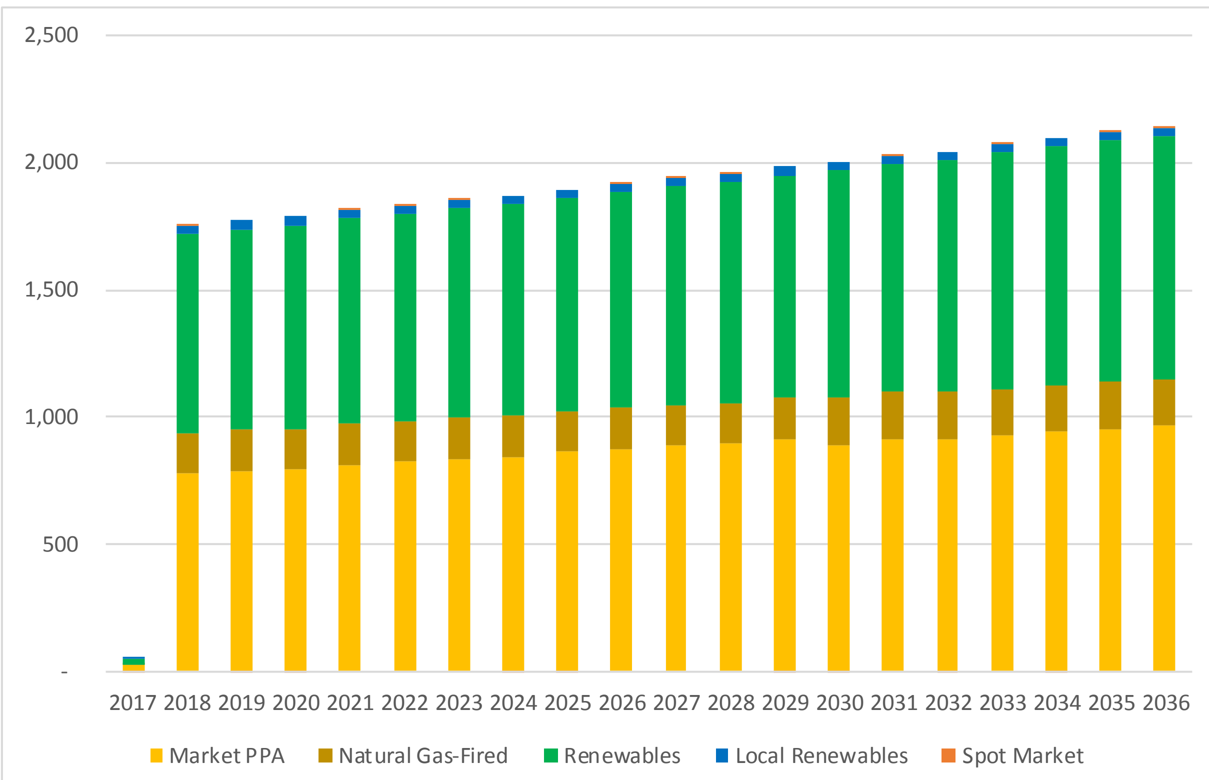


The green bars increase each year along with California's RPS requirements. The costs associated with this portfolio could be reduced if it was assumed that more power was purchased from market PPAs instead of non-renewable (natural gas-fired) resources. The percent of non-renewable energy purchased via market PPAs, as opposed to natural gas-fired resources, is the same in each of the three portfolios.

Portfolio 2: Serve 50% of Retail Load with Renewables Starting on Day 1

In this portfolio, the 50 percent renewable energy purchase requirement in the RPS is effectively moved up from 2030 to January 1, 2017. Beginning in 2018, the amount of power purchased from the relatively expensive ($65/MWh 20-year levelized cost) local renewables is held constant at 100 MW with an average monthly capacity factor of 33 percent in each of the three portfolios. As shown below in Exhibit 19 the green bars showing renewable energy purchases in 2017 through 2029 increased compared to those shown above in Exhibit 18.

Exhibit 19
Portfolio 2: Serve 50% of Retail Load with Renewables (aMW)



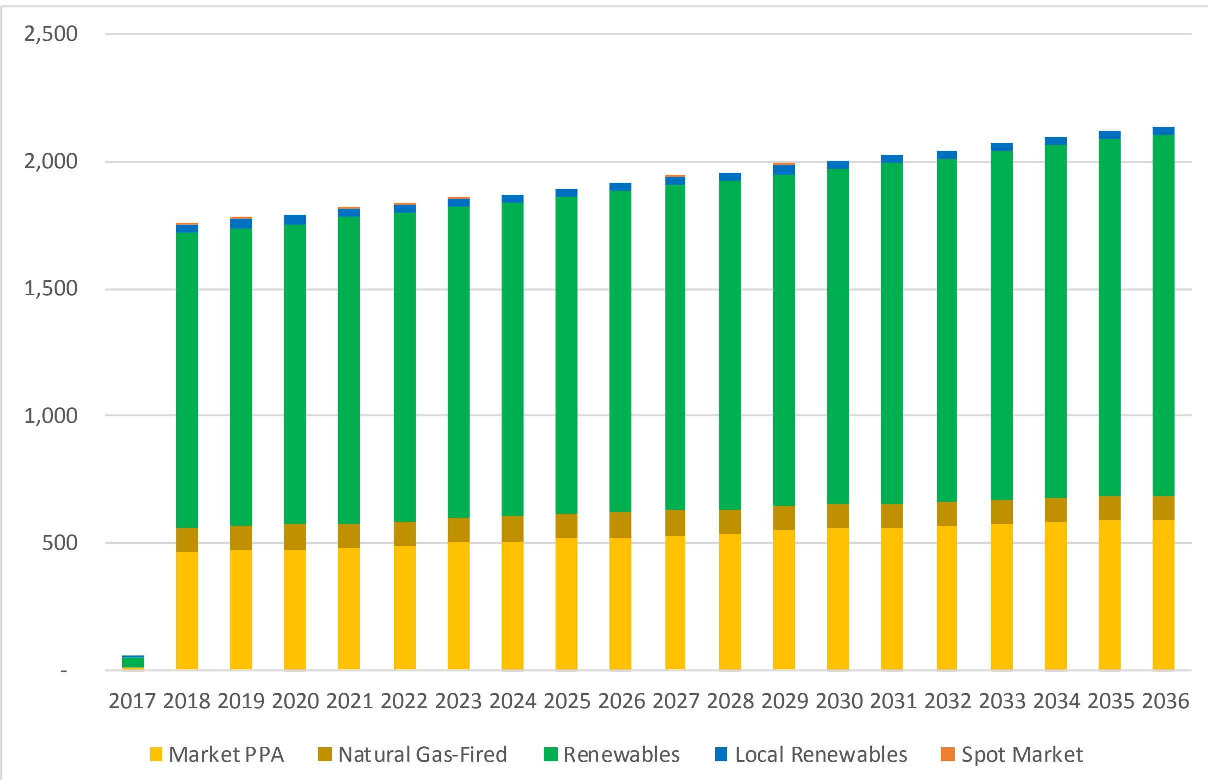
The percentage of non-renewable energy purchased from the more expensive natural gas-fired resources is approximately the same as Portfolio 1. In all three portfolios, approximately 15 percent of non-renewable energy is purchased from new gas-fired generation resources, which has a base case 20-year levelized cost of $60/MWh. In all three portfolios, 85 percent of non-renewable energy is purchased at the lower $44.3/MWh levelized cost associated with market PPA purchases.

Portfolio 3: Serve 100% of Retail Load with Renewables Starting on Day 1

In this portfolio retail loads are served entirely with renewable energy purchases. As in Portfolios 1 and 2, it is assumed that 100 MW of capacity from local renewable energy projects is available beginning in 2018. Exhibit 20 below shows the resource mix used to serve load in Portfolio 3.

The renewable energy requirements in the State's RPS are based on retail energy sales. To be consistent, it was assumed that the 100 percent renewable energy target would only apply to retail energy sales. The same concept applies to Portfolios 1 and 2. For example, renewable energy purchases in Portfolio 2 are equal to 50 percent of projected retail energy sales in all years.

Exhibit 20
Portfolio 3: Serve 100% of Retail Load with Renewables (aMW)



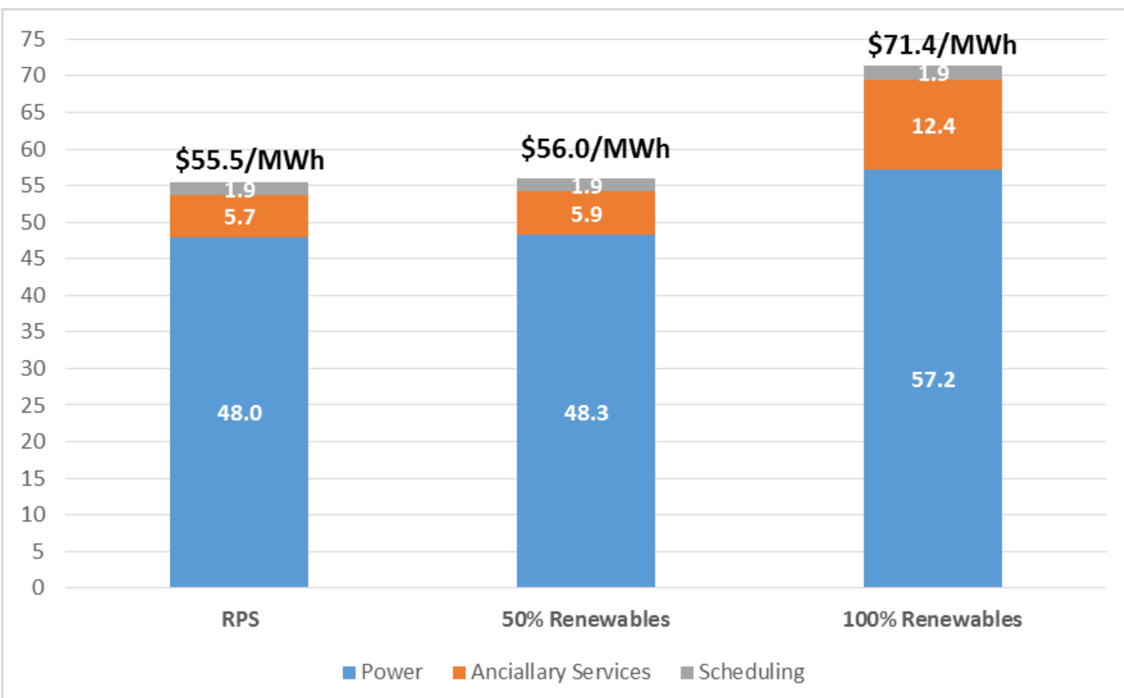
There is a significant amount of market PPA and brown resource power included in Portfolio 3 due to the mismatch between seasonal solar generation and seasonal loads. Solar generation is relatively low in winter months and peaks during summer months. Loads are also lower in the winter and higher in the summer. However, beginning in March solar generation ramps up faster than loads. This could put utilities in a position of having to find a market for relatively large amounts of surplus energy during the months of March through June when market prices are typically the lowest. Many utilities and generators will likely be surplus in the spring because of the mismatch between seasonal solar generation and loads in the spring. In addition, utilities and generators located in the Northwest also have surplus energy in the spring due to increased hydroelectric generation (due to melting snow) and wind. Non-renewable resources are included in Portfolio 3 in order to reduce ICP's exposure to low market prices during periods in which there is an abundance of surplus energy available in the region.

Non-renewable resources are needed in Portfolio 3 to serve load during hours when renewable resources are not capable of generating power (e.g., when the wind is not blowing or the sun is not shining). Purchasing large amounts of renewable generation, as in Portfolio 3, will likely result in over-supply in on-peak hours when solar projects are generating power and under-supply in off-peak hours when solar projects are not generating. As such, during some periods, on-peak energy may need to be exchanged for off-peak energy. The cost of exchanging or firming some of the solar generation into off-peak blocks of energy is reflected in higher ancillary service costs in Portfolio 3.

20-Year Levelized Portfolio Costs

The 20-year levelized costs have been calculated based on the base case assumptions detailed above regarding resource costs and resource compositions under the three portfolios. Exhibit 21 shows a breakdown of power, ancillary service and scheduling costs associated with each portfolio.

Exhibit 21
20-year Levelized Base Case Portfolio Costs ($/MWh)



As shown above Portfolio 1 and 2 power costs are fairly similar. There is not a large variance in power costs in these two portfolios because the majority of power is supplied by market PPA and renewable energy purchases in each portfolio. The projected costs of renewable energy and market PPA purchases are very close. Exhibit 23 shows that the projected 20-year levelized cost of renewables is $42/MWh while the projected 20-year levelized cost of market PPA purchases is $44.3/MWh. While the 20-year levelized cost of market PPA purchases is greater than the 20-

year levelized cost of renewables, market PPA purchase prices are assumed to escalate from $31/MWh in 2017 to $47/MWh in 2029. Portfolios 1 and 2 are identical beginning in 2030 when the RPS increases to 50 percent. Portfolio 1 has a slightly lower 20-year levelized cost because the cost of PPA market purchases is less than the cost renewables in 2017 through 2029.

Total costs under Portfolio 3 are approximately $15/MWh greater than Portfolios 1 and 2. The costs of renewables have been assumed to be $10/MWh greater in Portfolio 3 than in Portfolios 1 and 2 in recognition of the need for a more diverse mix of renewable resources. This translates into greater power costs (the blue bar) for Portfolio 3.

Each portfolio assumes that 15 percent of non-renewable energy is purchased from natural gas-fired resources with a projected 20-year levelized cost of $60/MWh. However, since more non-renewable energy is purchased in Portfolio 1 it has the highest percentage of natural gas-fired resource purchases. In Portfolio 1, 10 percent of power purchases are natural gas-fired resource purchases, compared to 9 percent in Portfolio 2 and 5 percent in Portfolio 3.

ICP Cost of Service

This section of the Plan describes the financial pro forma analysis and cost of service for ICP. It includes estimates of start-up costs, staffing and administrative costs, consultant costs, power supply costs, and SCE charges. In addition, it provides an estimate of start-up working capital and longer-term financial needs. The analysis and assumptions are first described for the ICP scenario. The financial impacts of three separate COGs are also described.

Cost of Service for ICP Base Case Operations

The first category of the pro forma analysis is the cost of service for ICP operations. To estimate the overall costs associated with ICP operations, the following components have been included:

- Power Supply Costs
- Non-Power Supply Costs
    - Start-up costs
    - ICP staffing and administration costs
    - Consulting Support
    - SCE and regulatory charges
    - Reserves
    - New Program Fund
    - Financing costs
- Pass-Through Charges from SCE
    - Transmission and distribution charges
    - Power Cost Indifference Adjustment (PCIA) Charge
    - Franchise Fee
    - Other non-bypassable charges

Once the costs of ICP operations have been determined, the total costs can be compared to SCE's projected rates.

Power Supply Costs

A key element of the cost of service analysis is the assumption that electricity will be procured under a power purchase arrangement (PPA) for both renewable and non-renewable power until local ICP resources can be developed. Power supply must be obtained by ICP's procurement contractor prior to commencing operations. The products required from the third party procurement are energy, capacity, renewable energy, load forecasting and scheduling coordination.

The calculated starting cost of electric power supply, including the cost of the scheduling coordinator and all regulatory power requirements, is between $45 and $65 per MWh. This price represents the price needed for a full requirements, load following electricity contract. The variation in price is a function of the desired level of renewable resources.

Non-Power Supply Costs

While power supply costs make up the majority of costs associated with operating ICP (roughly 80 percent), there are several additional cost components that must be considered in the pro forma financial analysis. These additional non-power supply costs are noted below.

Start-Up Activities and Costs

Monthly costs associated with ICP start-up and phasing of customer enrollments include expenditures for program staff/contract staff, associated infrastructure, contractor costs and fees payable to SCE by ICP. The estimated startup costs include capital expenditures and one-time expenses as well as ongoing expenses that will be accrued before significant revenues from ICP operations are realized. These cost components are quantified in Exhibit 22 and Exhibit 23 below.

Exhibit 22
Monthly Start-Up Cost Summary (ICP)

	2017 Pre-Start Costs					
	January	**February**	**March**	**April**	**May**	**June**
Start-Up Costs						
Infrastructure	$0	$0	$0	$0	$55,000	$35,000
Consultants	$70,000	$100,000	$100,000	$100,000	$125,000	$125,000
Staffing	$0	$0	$0	$0	$38,333	$51,677
Utility Trans. Fee	$0	$0	$780	$0	118,636	130,749
Total Start-Up	**$70,000**	**$100,000**	**$100,780**	**$100,000**	**$336,969**	**$342,416**

Exhibit 23
Start-Up Costs Summarized by Phase (ICP)

		Phase 1	**Phase 2**
	Total 2017 Pre-Start Costs	**July – December 2017**	**CY 2018**
Start-Up Costs			
Infrastructure	$90,000	$260,000	$350,000
Consultants (incl. Data Manager)	$620,000	$1,471,529	$15,724,632
Staffing	$90,000	$970,000	$2,488,333
Utility Trans. Fee	$250,165	$3,574,050	$8,197,628
Total Start-Up	**$1,050,165**	**$6,275,579**	**$26,760,549**

Other costs related to starting up ICP's program will be the responsibility of ICP's consultants and contractors. These include capital requirements paid by others, customer information system costs, electronic data exchange system costs, call center costs, and billing administration/settlements systems costs. The costs payable by ICP are contained in Exhibit 23.

Estimated Staffing Costs

For start-up, it is assumed that an operating team will be employed prior to the Board's selection of an Executive Director, per the example of other CCAs in California. This operating team includes one assistant Executive Director and one manager of policy and regulatory affairs and one administrative assistant. This staff is supported by consultants to manage and operate the CCA.

ICP will have a continuum of options for ongoing staffing. These options range from hiring all internal staff incrementally to match workloads involved in forming ICP, managing contracts, and initiating customer outreach/marketing during the pre-operations period (Full Staff Scenario) to hiring an entity to run the entire CCA operations. All of these options are discussed below.

Full Staff Scenario

At one end of the continuum, Exhibit 24 provides the estimated staffing budgets for the start-up period through 2018. Staffing budgets include direct salaries and benefits. Exhibit 24 details the anticipated staffing of ICP.

Exhibit 24
Staffing Plan (ICP)

Number of Staff	Pre Start-Up	2017 (Phase 1)	2018 (Phase 2)
Executive Director	0	1	1
Assistant Executive Director	1	1	1
Policy & Regulatory Manager	1	0	1
Regulatory Analyst	0	1	1
Administrative Assistant	1	1	2
Finance & Rates Manager	0	1	1
Rates Analyst	0	1	1
Accounting & Billing Analyst	0	1	2
Human Resources Manager	0	1	1
HR Specialist	0	1	1
Sales & Marketing Manager	0	1	1
Energy Efficiency Program Manager	0	0	1
Account Representatives	0	2	2
Communication Specialists	0	2	2
IT Manager	0	1	1
IT Specialist	0	0	1
Total Number of Employees	3	15	20
Total Staffing Costs	$90,000*	$970,000*	$2,488,333

*Represents only partial year.

Based on this staffing plan, ICP will initially employ 3 staff members. Once ICP has expanded its service area and operated for one year or so, it is anticipated that staffing will increase to approximately 20 employees. These positions to be hired by ICP over the first two years are described below:

Executive Director

The Executive Director will be responsible for overseeing ICP operation and ensuring that the vision of the JPA Board is followed. The Executive Director will ultimately be responsible for all ICP programs, finances and communication programs plus be accountable to the Board.

Assistant Executive Director

The Assistant Executive Director will oversee the day to day operation of ICP. In particular, this staff position will work closely with outside consultants, and oversee hedging and power procurement, resource portfolio strategy, CAISO settlements and other financial planning and rate setting analysis. Behind the meter ICP programs will also be coordinated through this position.

Policy and Regulatory Manager

The Policy and Regulatory Manager will oversee the legal and regulatory functions of ICP. This position will work closely with the CPUC and State/Federal legislators. ICP will require ongoing regulatory representation to file resource plans, resource adequacy compliance, compliance with California RPS, and overall representation on issues that will impact ICP and its customers. ICP should plan on maintaining an active role at the CPUC, CEC, FERC and the California legislature.

Finance and Rates Manager

The Finance and Rates Manager oversees ICP's budgets and accounting functions. In addition, this person will develop annual budgets, rates and credit policies for approval by the Board. Managing the overall financial aspects of ICP is expected to be a significant work activity.

Sales and Marketing Manager

The Sales and Marketing Manager is responsible for the enrollment and notification of new customers. In addition, this staff person will market ICP, and provide on-going communication with ICP's communities and customers. A significant amount of customer service and key account representation will be necessary in addition to regular marketing services. This position will be the point person for the outsourced data management and customer service consultants.

Administrative Assistant

The staffing plan assumes a full-time administrative assistant will be added during the pilot phase to provide administrative assistance to management.

Future Staff

As additional customers join ICP, duties can be shifted from third-party consultants to in-house staff if internal staffing is more cost effective.

Third-Party Operator Scenario

At the other end of the continuum, ICP's Board could hire a third-party vendor to operate the CCA. Under this option, the Board would likely issue an RFP for the requested services, evaluate the responses, then decide whether to fully staff internally, hire some internal staff and some consultants, or turn the entire CCA operation over to a third party.

It should be noted that the existing California CCAs have opted for an organizational structure that features a significant number of internal staff as opposed to using all consultants to operate their CCA. There are many reasons for this type of operational structure but two primary reasons are:

- The size of the CCA is such that in most cases it is the largest enterprise found among the CCA participants.
- This CCA will have direct contact with most of the governing body's constituents at least once a month through the CCA billing process.

Because of these noteworthy observations, existing CCAs have adopted more of a "hands on" organizational structure, but the preferred operational mode for a new CCA is ultimately dictated by the Board.

Estimated Infrastructure Costs

Infrastructure or overhead needed to support the organization includes computers and other equipment, office furnishings, office space and utilities. These expenses are estimated at $90,000 during program pre-startup. Office space and utilities are ongoing monthly expenses that will begin to accrue before revenues from program operations commence and are therefore assumed to be financed as shown in Exhibit 25 and Exhibit 26

Exhibit 25
Monthly Estimated Infrastructure Costs (ICP)

	2017 Pre-Start					
	January	February	March	April	May	June
Infrastructure Costs						
Computers	$0	$0	$0	$0	$15,000	$5,000
Furnishings	$0	$0	$0	$0	$15,000	$5,000
Office Space	$0	$0	$0	$0	$15,000	$15,000
Utilities/Other Office Supplies	$0	$0	$0	$0	$10,000	$10,000
Total Start-Up	**$0**	**$0**	**$0**	**$0**	**$55,000**	**$35,000**

Exhibit 26
Estimated Infrastructure Cost by Phase (ICP)

	2017	Phase 1	Phase 2
	Total Pre-Start Costs	July – December 2017	CY 2018
Infrastructure Costs			
Computers	$20,000	$55,000	$25,000
Furnishings	$20,000	$55,000	$25,000
Office Space	$30,000	$90,000	$180,000
Utilities/Other Office Supplies	$20,000	$60,000	$120,000
Total Infrastructure Costs	**$90,000**	**$260,000**	**$350,000**

It is estimated that the per employee start-up cost is approximately $10,000. This expense covers computer and furniture needs. An additional annual expense of $180,000 for office space, and approximately $120,000 per year in office supplies and utilities costs is expected. In addition, it is assumed that computers will need to be replaced every 5 years and furnishings every 10 years.

Utility Implementation and Transaction Charges

The estimated costs payable to SCE for services related to ICP start-up include costs associated with initiating service with SCE, processing of customer opt-out notices, customer enrollment, post enrollment opt-out processing, and billing fees. These distribution utilities fees are explicitly stated in the relevant SCE tariffs.

Customers who establish service with ICP will be automatically enrolled in the program and have sixty days from the date of enrollment to customer opt-out of the program. Such customers will be provided with two opt-out notices within this sixty-day post enrollment period. The first notice will be mailed to customers approximately sixty days prior to the date of automatic enrollment. A second notice will be sent approximately thirty days later. Following automatic enrollment, two additional opt-out notices will be provided within the sixty-day period following customer enrollment. It is estimated that the enrollment charges will be approximately $3.4 million for 2017 and $3.5 million for 2018, as shown in Exhibit 27 and Exhibit 28. Enrollment charges are almost as high in 2017 because Phase 2 enrollment starts prior to Phase 2 implementation.

Exhibit 27
Monthly Utility Transaction Fees (ICP)

	Pre-Start					
	January	**February**	**March**	**April**	**May**	**June**
Enrollment Charges	0	0	780	0	$118,636	$130,749
Ongoing Charges	0	0	0	0	0	0
Total SCE Transaction Fee	**$0**	**$0**	**$780**	**$0**	**$118,636**	**$130,749**

Exhibit 28
Utility Transaction Fees by Phase (ICP)

		Phase 1	Phase 2
	Total Pre-Start Costs	**2017**	**2018**
Enrollment Charges	$250,165	$3,402,449	$3,469,521
Ongoing Charges	0	171,601	$4,728,107
Total SCE Transaction Fees	**$250,165**	**$3,574,050**	**$8,197,628**

Estimates of Third Party Contractor Costs

Contractor costs include outside assistance for advertising, legal services, resource and financial planning, implementation support, customer enrollment, customer service, and payment processing/accounts receivable and verification. The latter three will be provided by ICP's customer account services provider, and these preliminary estimates will be refined as the services and costs provided by the selected contractor are negotiated. Exhibit 29 and Exhibit 30 show the estimated contractor costs during the startup period assuming full staff scenario is implemented.

Exhibit 29 Monthly Estimated Consultant Costs (ICP)						
	Pre-Start					
	January	February	March	April	May	June
Legal/Regulatory	$20,000	$50,000	$50,000	$50,000	$50,000	$50,000
Communication	$0	$0	$0	$0	$25,000	$25,000
Data Management	$0	$0	$0	$0	$0	$0
Financial Consulting	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000
Total Consultant Costs	**$70,000**	**$100,000**	**$100,000**	**$100,000**	**$125,000**	**$125,000**

Exhibit 30 Estimated Consultant Costs by Phase (ICP)			
		Phase 1	Phase 2
	Total Pre-Start Costs	2017	2018
Legal/Regulatory	$270,000	$300,000	$480,000
Communication	$50,000	$150,000	$300,000
Data Management	$0	$731,529	$14,414,632
Financial Consulting	$300,000	$290,000	$530,000
Total Consultant Costs	**$620,000**	**$1,471,529**	**$15,724,632**

The estimate for each of the services is based on costs experienced by other CCAs. Consultant costs are increased by inflation every year.

Estimated Reserves

ICP is assumed to receive capital financing during its startup phase. After a successful launch, ICP should strongly consider building up a reserve fund that is available to address contingencies, cost uncertainties, rate stabilization or other risks faced by ICP. This Plan assumes that ICP will begin building its reserves starting from its launch. It is assumed that the first year's reserve funds can be used to pay off loans. After four years, the assumed savings rate will have accumulated enough reserves for 3 months of expenses. This level of reserves will provide financial stability and assist ICP in obtaining favorable rates if additional financing is needed. After that point, additional savings can begin to fund lower rates, more programs and/or economic development projects (see Programs Section).

Estimated New Programs Fund

Once the reserve fund has reached its target, the revenue requirement includes budget for new customer programs including DER support, additional energy efficiency program offering, further rate discounts, etc. These programs have not been identified at this time as the Board will make the decision of priorities for funding.

Cash Flow Analysis and Working Capital

This cash flow analysis estimates the level of working capital that will be required until full operation of ICP is achieved. For the purposes of this Plan, it is assumed that ICP pre-operations begin in January 2017 and continue through June 2017. In general, the components of the cash flow analysis can be summarized into two distinct categories: (1) Cost of ICP operations, and (2) Revenues from ICP operations. The cash flow analysis identifies and provides monthly estimates for each of these two categories. A key aspect of the cash flow analysis is to focus primarily on the monthly costs and revenues associated with ICP and specifically account for the transition or "Phase-In" of ICP customers. The cash flow analysis assumes the phase-In schedule for ICP as described previously.

The cash flow analysis also provides estimates for revenues generated from ICP operations or from electricity sales to customers. In determining the level of revenues, the cash flow analysis assumes the customer phase-in schedule noted above, and assumes that ICP provides a discount of 3.8 percent from the existing rates for each customer class, where pre-operations run from January 1, 2017 to June 31, 2017. Thereafter, Phase 1 starts in July 2017.

The results of the cash flow analysis provide an estimate of the level of working capital required for ICP to move through the pre-operations period. This estimated level of working capital is determined by examining the monthly cumulative net cash flows (revenues minus cost of operations) based on assumptions for payment of costs by ICP, along with an assumption for when customer payments will be received. The cash flow analysis assumes that customers will make payments within 60 days of the service month, and that ICP will make payments to suppliers within 30 days of the service month. This analysis is somewhat conservative because customer payments begin to come in soon after the bill is issued, and most are received before the due date. At the same time, some customer payments are received well after the due date. The 30-day net lag is a conservative assumption for cash flow purposes.

For purposes of determining working capital requirements related to power purchases, ICP will be responsible for providing the working capital needed to support electricity procurement unless the electricity provider can provide the working capital as part of the contract services. In addition, ICP will be obligated to meet working capital requirements related to program management. For this Plan, it is assumed that this working capital requirement is included in the short term financing associated with start-up funding. Several operating CCAs have been successful in negotiating lines of credit, lockbox arrangements and delayed payment arrangements which reduce the cost of working capital. Any of these arrangements will reduce the cost of working capital and increase the potential savings to customers.

A summary of working capital needs is presented below on Exhibit 31.

Exhibit 31
Working Capital Needs (ICP)

	2017	2018
Working Capital (ICP)	$12 Million	$150 Million

Total Financing Requirements

The start-up of the ICP program will require a significant amount of capital for three major functions: (1) staffing and contractor costs; (2) program initiation; and (3) working capital. Each of these anticipated requirements is discussed below.

Staffing costs for the pre-implementation period (January 2017 through June 2017) are estimated to be approximately $90,000. Contractor costs for the same time period are estimated to be approximately $620,000. These costs include: advertising/communications, consulting, legal, and data management.

ICP initiation costs include the infrastructure that ICP will require (office space, utilities, computers) as well as the distribution utility fees for initiating ICP. Infrastructure costs are estimated to be approximately $90,000 and the distribution utility fees are estimated to be approximately $250,165.

The Public Utilities Code requires demonstration of insurance or posting of a bond sufficient to cover reentry fees imposed on customers that are involuntarily returned to SCE service under certain circumstances. In addition, SCE requires a bond equivalent to two months of transaction fees.

For the ICP scenario, the total financing requirement, including working capital, during the start-up and pilot periods, are estimated to be approximately $20 million, increasing to approximately $175 million following full enrollment. The first $20 million is needed in Spring 2017.

Financing Plan

The initial start-up funding will be provided via short-term financing. ICP will recover the principal and interest costs associated with the start-up funding via subsequent retail rates. It is anticipated that the start-up costs will be fully recovered within the first five years of ICP operations.

Additional financing will be needed at the beginning of Phase 2. Depending on market conditions and payment terms established with the third-party suppliers, the loan may need to be increased to approximately $175 million for the start of Phase 2. This number will be refined as the ICP program becomes operational, and bids are received from power providers.

Based on recent information regarding financing options for CCA's, the Plan's financial analysis assumes that ICP can obtain a loan for the first $20 million with a term of 5 years at a rate of 5.5 percent. The second loan for $175 million is assumed for a 20-year term at 5.5 percent.

The detail of the base case financial analysis is provided in Appendix B.

Cost of Service for Three CCA Operations

There are several options for how to setup and operate a CCA. In addition to forming one CCA as outlined as the base case in the Plan, three CCAs (one for each COG), or individual jurisdictions is an option. This option would entail each of the three COGs or an individual jurisdiction providing a full service CCA including power procurement, data management and local program development/outreach.

In order to develop this three CCA scenario, each major cost component has been reviewed to determine the appropriate cost structure for each individual CCA based on the size of load. Power procurement, SCE charges and data management costs follow load and number of customers in each CCA. However, the internal costs (staffing, office space, consulting) are about the same for a 100,000-meter utility, and a 1,000,000-meter utility. The results are shown for the 50% Renewable portfolio, but Appendix B provides the results for all three power supply scenarios for each of the three COGs separately.

"Three CCA" Assumptions

It is anticipated that if the three COG's operate separately, staffing would be fairly similar to the ICP scenario for each of the CCA's. Exhibit 32 provides the estimated staffing and annual cost under the separate CCA scenario. Again, the Plan is looking at the most conservative numbers to show the feasibility of implementing a CCA, the Plan does not specify that this option hire all in-house staff from the beginning, nor does it specify that a CCA should hire all of the staff listed below. The information below is based on the staffing currently being provided by Marin Clean Energy, Lancaster Choice Energy, and Sonoma Clean Energy.

Exhibit 32
Staffing Plan (Three CCAs)

Number of Staff	CVAG	SANBAG	WRCOG
Executive Director	1	1	1
Assistant Executive Director	1	1	1
Policy & Regulatory Manager	1	1	1
Regulatory Analyst	0	1	1
Administrative Assistant	2	2	2
Finance & Rates Manager	1	1	1
Rates Analyst	0	1	1
Accounting & Billing Analyst	2	2	2
Human Resources Manager	0	1	1
HR Specialist	0	1	0
Sales & Marketing Manager	0	1	0
Energy Efficiency Program Manager	1	1	1
Account Representatives	0	2	2
Communication Specialists	0	2	0
IT Manager	0	1	1
IT Specialist	0	1	1
Total Number of Employees	9	20	16
Total Staffing Costs	$1,190,000	$2,488,333	$1,704,167

The estimated start-up costs for each of the COGs and the combined "Three CCA" scenario are shown in Exhibit 33.

For the separate scenarios, computers, furnishings and supplies were forecast based on employees in each CCA. In the WRCOG scenario, staff is added slower than in the SANBAG scenario, thus delaying some staffing and infrastructure costs from 2017 to 2018.

Exhibit 33
Estimated Infrastructure Cost by Phase (Three CCAs)

		Phase 1	Phase 2
	Total Pre-Start Costs	**2017**	**2018**
Infrastructure Costs			
CVAG	$90,000	$150,000	$350,000
SANBAG	$90,000	$260,000	$350,000
WRCOG	$90,000	$150,000	$420,000
Total Infrastructure Costs	**$270,000**	**$560,000**	**$1,120,000**

The estimated costs payable to SCE for services related to ICP start-up include costs associated with initiating service with SCE, processing of customer opt-out notices, customer enrollment, post enrollment opt-out processing, and billing fees. These distribution utilities fees are explicitly stated in the relevant SCE tariffs. The utility transaction fees for each of the COGs separately, are shown in Exhibit 34.

Exhibit 34
Utility Transaction Fees by Phase (Three CCAs)

		Phase 1	Phase 2
	Total Pre-Start Costs	**2017**	**2018**
CVAG	$39,557	$413,653	$918,803
SANBAG	$149,501	$1,939,421	$4,405,258
WRCOG	$68,749	$1,228,726	$2,873,783
Total SCE Transaction Fees	**$257,807**	**$3,581,800**	**$8,197,844**

Exhibit 35 shows the estimated contractor costs during the startup period for the "Three CCA" scenario. These are costs assumed for financial and accounting assistance, legal assistance, data management and communication.

Exhibit 35
Estimated Consultant Costs by Phase (Three CCAs)

		Phase 1	Phase 2
	Total Pre-Start Costs	**2017**	**2018**
CVAG	$620,000	$606,215	$2,398,639
SANBAG	$620,000	$1,172,679	$9,074,423
WRCOG	$620,000	$932,634	$6,331,569
Total Consultant Costs	**$1,860,000**	**$2,711,528**	**$17,804,631**

Estimated non-power supply costs associated with ICP start-up and phasing of customer enrollments for the "Three CCA" scenarios are provided in Exhibit 36.

Exhibit 36 Start-Up Costs for Three CCAs Summarized by Phase						
	CVAG	CVAG	SANBAG	SANBAG	WRCOG	WRCOG
	2017	2018	2017	2018	2017	2018
Start-Up Costs						
Infrastructure	$240,000	$350,000	$350,000	$350,000	$240,000	$420,000
Consultants	$1,226,215	$2,398,639	$1,792,679	$9,074,423	$1,552,634	$6,331,569
Staffing	$400,000	$1,190,000	$1,060,000	$2,488,333	$400,000	$1,704,167
Utility Trans. Fee	$453,211	$918,803	$2,088,921	$4,405,258	$1,297,475	$2,873,783
Total Start-Up	**$2,319,426**	**$4,857,442**	**$5,291,600**	**$16,318,014**	**$3,490,109**	**$11,329,519**

Each CCA will be responsible for providing the working capital needed to support electricity procurement unless the electricity provider can provide the working capital as part of the contract services. In addition, each CCA will be obligated to meet working capital requirements related to program management. It is assumed that this working capital requirement is included in the short term financing associated with start-up funding. A summary of working capital needs for the three CCAs is presented below on Exhibit 37.

Exhibit 37 Working Capital Needs		
	2017	2018
Working Capital (CVAG)	$3 Million	$35 Million
Working Capital (SANBAG)	$5 Million	$75 Million
Working Capital (WRCOG)	$4 Million	$50 Million

For the "Three CCA" scenario, the total financing requirements, during the start-up and pilot periods, are estimated to be approximately $22 million with $5 from CVAG, $10 million from SANBAG and $7 million from WRCOG. Before full enrollment, additional capital in the order of $190 million will be needed from the three COGs following full enrollment. The first $22 million is needed in Spring 2017.

The option to form three CCAs within ICP has some initial appeal. If each COG formed a CCA, each would achieve greater local control and avoid potential governance issues. However, the goal of providing the lowest possible rates would not be achieved. As such, forming three CCAs versus one for back office functions would cost the CCA customers an addition $17 million in the first year of operating (when including the need to build reserves) and an additional $7 - $9 million per year in operating costs on an ongoing basis. This is a material amount of economic inefficiency. However, the additional cost is only a small portion of total program costs at 1.7 percent in the first year and roughly 1 percent in the subsequent years. Therefore, it remains a viable option if the separate COGs value local control at that premium. A summary of the comparison between organizational structures is shown in Exhibit 38.

Exhibit 38 Comparison between Organizational Structures			
	Total Start-Up Costs	**Operating Costs**	**Estimated Rate Savings**
	2017	**2018**	**2018**
CVAG	$2,319,426	$124,635,397	2.1%
SANBAG	$5,291,601	$535,477,882	3.4%
WRCOG	$3,490,109	$320,724,514	3.0%
Three COGs Combined	**$11,101,136**	**$980,837,793**	
ICP	$7,325,744	$963,997,388	3.7%
Savings/Year	**$3,775,392**	**$16,840,405**	

Products, Services, Rates Comparison and Environmental/Economic Impacts

This section of the Plan provides a comparison of service and rates between SCE and ICP. Rates are evaluated based on total ICP electric total bundled rates as compared to SCE's total bundled rates. Total bundled electric rates include the rates charged by ICP, including non-bypassable charges, plus SCE's delivery charges. This section also includes the environmental impacts based on the reduction in Green House Gases (GHG), and the economic development impact on local jobs and overall economic activity created by ICP programs.

Rates Paid by SCE Bundled Customers

The average customer weighted SCE rates have been calculated based on current rate schedules and ICP's projected customer mix. SCE's current 2016 rates and surcharges have been applied to customer load data aggregated by major rate schedules to form the basis for the SCE rate forecast.

The average SCE delivery rate, which is paid by both SCE bundled customers and ICP customers, has been calculated based on the forecasted customer mix for ICP. For future years, the SCE rate forecast assumes the delivery costs will increase by 2 percent per year, a conservative assumption given the history of SCE rate increases.

Similarly, the current average power supply rate component for SCE bundled customers has been calculated based on the estimated ICP customer mix. The SCE power supply rate component has been forecast to increase based on SCE's most recent filings and incorporating the increased RPS requirement mandated by SB 350. The most recent Energy Resource Recovery Account (ERRA) filing has been used to determine the 2017 SCE generation rates for each rate category. Finally, the SCE power supply rates have been projected to increase based on the renewable and non-renewable market price forecast, regulatory requirement for RPS, storage requirement and resource adequacy objectives.

Rates Paid by ICP Customers

It is anticipated that ICP's rate designs will initially mirror the structure of SCE's rates with the appropriate discounts so that similar rates can be provided to ICP's customers. In determining the level of ICP rates, the financial analysis assumes the customer phase-in schedule noted above and that the implementation phase costs are financed via a start-up loan.

In addition to paying ICP's power supply rate, ICP customers will pay the SCE delivery rate and non-bypassable charges. The calculation of the delivery rate is described earlier. The non-bypassable charges that are payable to SCE by ICP customers include:

- Power Cost Indifference Adjustment (PCIA)
- Department of Water Resources Bond Charge (DWRBC)
- Competition Transition Charge (CTC)
- Generation Municipal Surcharge (or Franchise Charge)

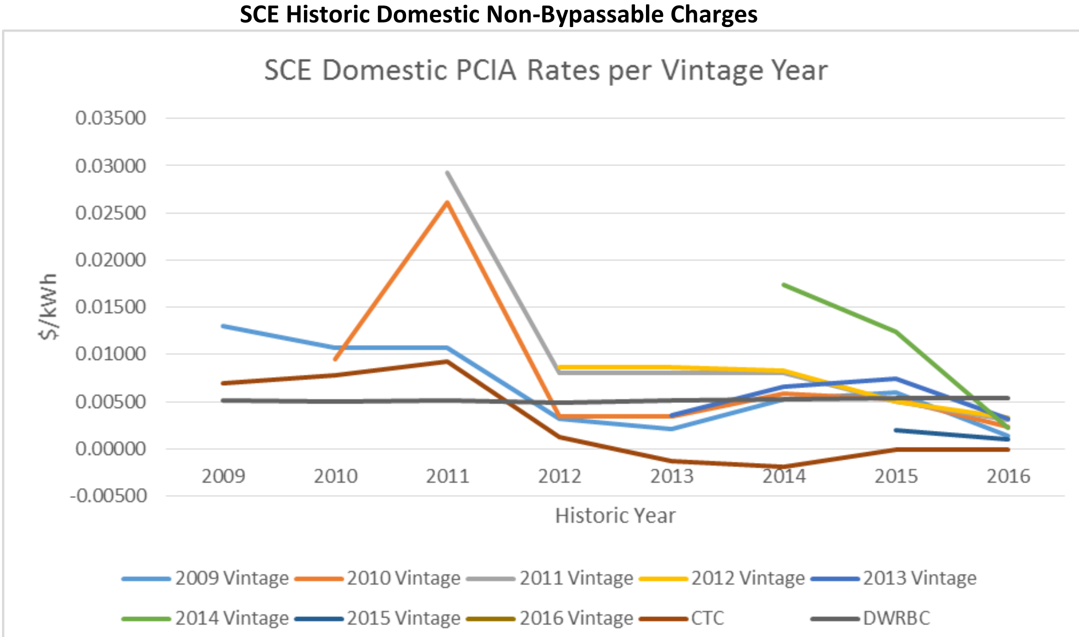
The DWRBC is the charge to recover the interest and principal of the California Department of Water and Resources (DWR) bonds. This charge is projected to remain at the current level and is scheduled to end in 2023. The CTC is the ongoing charge, which recovers the above market costs of utility generation. This charge is minimal at the moment and is not expected to be a significant cost to ICP customers.

Power Cost Indifference Adjustment (PCIA)

The PCIA is a charge that is designed to keep bundled customers "indifferent" when other customers leave bundled service. The PCIA is calculated annually by subtracting the market price of wholesale power from the incumbent utility's average cost of power supply based on a methodology determined by the CPUC.[8]

Exhibit 39 provides the historic values of the PCIA, CTC and DWRBC for the residential class. It is important to note that the non-by passable charges differ by the vintage of a CCA. The vintage of the CCA depends on when the CCA provides a binding notice of intent to SCE.

Exhibit 39
SCE Historic Domestic Non-Bypassable Charges



Note that CARE and medical base line customers do not pay the DWRBC or PCIA charges.

[8] See D.-6-07-030 as modified by D. 11-12-018.

For this Plan, it was assumed in the base case that the PCIA changes based on the differential between SCE's generation cost and market prices. For this Plan, PCIA is forecast to increase initially due to the end of offsetting credits that expire in 2018. Post-2018, the PCIA is expected to grow based on the inverse of the market price growth rate. The PCIA is calculated based on the difference between SCE's surplus resource cost and the market price. Therefore, as market prices increase, SCE's PCIA rate decreases as their surplus resources become more cost effective relative to market prices.

Generation Municipal Surcharge (or Franchise Fee)

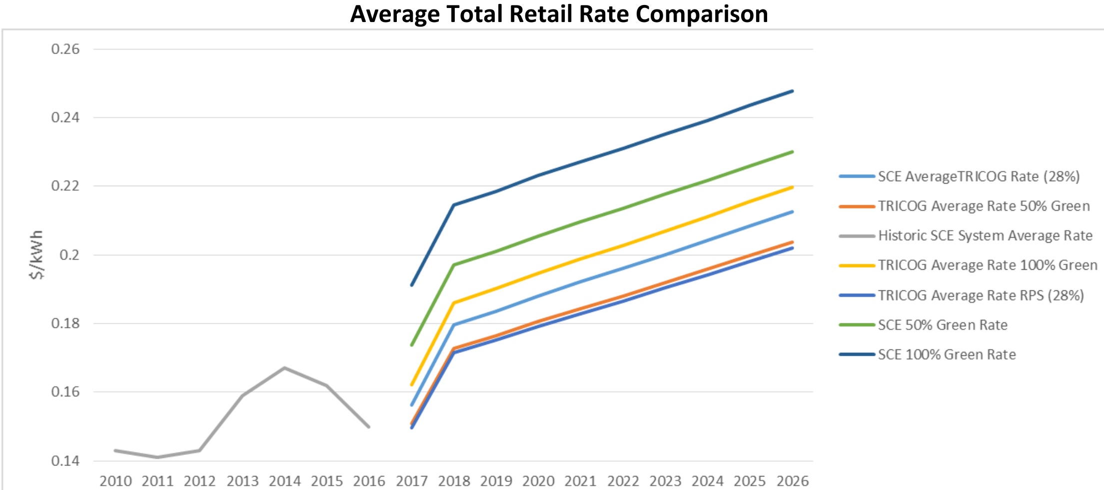
The franchise fee is a surcharge that SCE pays cities and counties for the right to use public streets to provide utility services. The franchise fee is a revenue source for municipalities implemented on privately owned utilities. The franchise Fee is a "rental" or "toll for the use of a municipality's streets and poles, as well as for permission to provide service in their jurisdiction. The Franchise Act establishes that a franchise fee of 2 percent of the franchisees gross annual receipts arising from the use, operation, or possession of the franchise …. within the city limits.[9]"

SCE collects the surcharges and passes them to cities and counties. This tax is part of SCE's current rates and is therefore passed on to the CCA customers as a non-bypassable charge called the Generation Municipal Surcharge. SCE will continue to collect the franchise fees for both generation and distribution services and pay the cities and counties the owed revenue. The franchise fee is not forecast to change during the analysis horizon.

Rate Impacts

Based on ICP's projected power supply costs and operating costs, and SCE's power supply and delivery costs, forecasts of ICP and SCE total rates have been developed. These rates are illustrated below on Exhibit 40.

Exhibit 40
Average Total Retail Rate Comparison



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[9] The California Municipal Law Handbook. 2002 Edition

For this Plan, it has been assumed that the projected rate decrease is applied uniformly across all rate classes. Once established, it will be up to the ICP Board and staff to develop rates for each rate class that reflects cost of service. Based on these assumed ICP discounts off the comparable SCE rate, Exhibit 41 provides a comparison of the indicative bundled rates for ICP's products with the current SCE rate.

Exhibit 41
Indicative Rate Comparison in ¢/kWh (First Full Year of Service)

Rate Class	Customer Type	2017 Estimated SCE Bundled Rate*	ICP RPS Bundled Rate	SCE 50% Green Bundled Rate	ICP 50% Green Bundled Rate	SCE 100% Green Bundled Rate	ICP 100% Green Bundled Rate
Residential	Domestic	20.55	19.58	22.30	19.81	24.05	21.79
Residential Care	Domestic	12.22	11.64	13.97	11.78	15.72	12.96
GS-1	Commercial	17.03	16.23	18.78	16.41	20.53	18.06
GS-2	Commercial	16.57	15.79	18.32	15.97	20.07	17.57
GS-3	Industrial	14.71	14.02	16.46	14.18	18.21	15.60
PA-2	Public Authority	13.08	12.46	14.83	12.61	16.58	13.87
PA-3	Public Authority	11.31	10.78	13.06	10.90	14.81	11.99
TOU-8 Secondary	Domestic	13.07	12.45	14.82	12.60	16.57	13.86
TOU-8 Primary	Commercial	11.84	11.28	13.59	11.41	15.34	12.55
TOU-8 Substation	Industrial	7.76	7.39	9.51	7.48	11.26	8.23
Initial Total ICP Rate Savings over Comparable SCE Rates of 50% or 100% Green			4.9%		11.2%		9.4%
Initial Total ICP Rate Savings over SCE's Standard Bundled Rate			4.9%		3.8%		-5.7%

*SCE bundled average rate based on SCE's ERRA 2017 Draft Filing

Exhibit 42 shows the initial rate savings associated with the formation of a CCA. By referencing Appendix B, these initial savings increase after ICP becomes fully functional. The savings by rate schedule after ICP is fully functional are presented below in Exhibit 42.

Exhibit 42
CCA Rate Savings at Fully Functional Operations

Power Supply Scenario	Range of Savings*
ICP RPS	4.9% - 5.7%
ICP 50% Renewable	3.8% - 4.5%
ICP 100% Renewable	(5.7%) – (5.0%)

*Note Appendix B for detail.

A financial proforma in support of these rates can be referenced in Appendix B.

It should be noted that the rate savings noted in ES-2 still allow the accumulation of significant reserves for the CCA. As illustrated in Appendix B, the proforma include a line item called "Contribution to Annual Reserves" that go towards funding the needed cash working capital (approximately $250M). After the target reserves have been met, additional reserves can be used to further lower CCA retail rates, invest in local renewable projects, provide additional energy efficiency programs, or any other CCA-related activity as directed by the CCA's Board. The projected funds available for this purpose are provided in the line item titled "New Programs" in the proforma. It is widely held that Proposition 26 prohibits the use of these reserves for any non-CCA related activity. The accumulate reserves and new program accruals present the new CCA with a large amount of funding and numerous opportunities going forward.

Exhibit 43 below highlights how much financial reserves are generated among the rate reductions noted above.

Exhibit 43
Accumulative Fund Balances for Financial Reserves and New Programs Under the 50% Renewable

Year	Accumulative Financial Reserve Funds ($ x 1000)	Accumulative New Project Funds ($ x 1000)	Total Financial Reserves ($ x 1,000)
2018	$63,330	$0	$63,330
2019	$130,225	$0	$130,225
2020	$213,504	$0	$213,504
2021	$259,527	$46,022	$305,549
2022	$259,527	$147,956	$407,483
2023	$259,527	$262,232	$521,759
2024	$259,527	$384,563	$644,090
2025	$259,527	$515,637	$775,164
2026	$259,527	$653,238	$912,765
2027	$259,527	$796,925	$1,056,452
2028	$259,527	$946,175	$1,205,702
2029	$259,527	$1,101,642	$1,361,169
2030	$259,527	$1,254,153	$1,513,680

These new project and financial reserve fund balances can be used for CCA-related activities as directed by the Board. These fund balances can also be used for rate reductions larger than calculated in the Plan's base case.

Local Resources/Behind the Meter ICP Programs

ICP may wish to plan to establish a Net Energy Metering ("NEM") program for qualified customers in their service territory to encourage DER. In addition, ICP should work with State agencies and SCE to promote deployment of distributed energy resources (DER) within ICP's service territory, with the goal of maximizing use of the available incentives that are funded through current utility distribution rates and public goods surcharges.

ICP should also consider establishing a program which offers a combination of retail tariffs, rebates, incentives and other bundled offerings intended to increase customer participation in demand-side programs including: renewable distributed energy resources, energy storage, energy efficiency, demand response, electric vehicle charging, and other clean energy benefits defined as Distributed Energy Resources (DER). ICP can work with State agencies and SCE to promote deployment of DERs in specific and targeted locations throughout SCE's distribution grid in order to help support efficient grid operations and maintenance as part of development of the future "smart grid".

Impact of Resource Plan on Greenhouse Gas (GHG) Emissions

The amount of renewable power in SCE's power supply portfolio is 28 percent[10] and will rise to 33 percent by 2020. Based on power supply strategy described previously, the estimated GHG emission reductions attributable to forming ICP are forecast to range from 1.33 to 2.34 million metric tons CO_2e per year by 2018 assuming a 50 percent RPS target is achieved. The baseline for comparison is the resource mix used by SCE versus the resource mix that will be utilized by ICP. Exhibit 44 details these reductions.

Exhibit 44
Baseline Comparison of GHG Reduction by ICP by 2018

	ICP	CVAG	SANBAG	WRCOG
Forecast Renewables (50% Renewables) ICP (GWH) – Phase 2	7,533	916	4,184	2,433
ICP RPS (GWH) – Phase 2	4,219	513	2,343	1,362
Additional Green Power	3,315	403	1,841	1,070
CO2 reduction – Low (Million Metric tons CO_2e)	1.33	0.16	0.74	0.43
CO2 reduction – High (Million Metric tons CO_2e)	2.34	0.28	1.30	0.76

The reductions in GHG associated with ICP operations are significant. This amount of reduced emissions represents a reduction in the emissions from the in-State generation resources from 2.6 to 4.6 percent.

Economic Development

The analyses contained in this Plan for forming ICP has focused on the direct rate effects of this formation. However, in addition to direct effects, indirect microeconomic effects are also encountered.

The indirect effects of creating ICP include the effects of increased commerce, and improved environmental and health conditions. Within this Plan, an Input/Output (IO) analysis is undertaken to analyze these indirect effects. The IO model turns on the assumption that forming ICP will lead to lower energy rates for their customers. Three types of impacts are analyzed in the IO model. These are described below.

Local Investment - ICP may choose to implement programs to incentivize investments in local

[10] http://www.cpuc.ca.gov/RPS_Homepage/

distributed energy resources (DER). These resources can be behind the meter or community projects where several customers participate in a centrally located project. This demand for local resources will lead to an increase in the manufacturing and installation of DER, and lead to an increase in employment in the manufacturing and construction sectors.

Increased Disposable Income - Establishing ICP will lead to reduced customer rates for energy, more disposable income for individuals and greater revenues for businesses. These cost savings would then lead to more investment by individuals and businesses for personal or business purposes. This increase in spending will then lead to increased employment for multiple sectors such as retail, construction, and manufacturing.

Environmental and Health Impacts - With the creation of ICP, other non-commerce indirect effects will occur. These may be largely environmental such as improved air quality or improved human health due to ICP adopting mainly renewable energy sources versus continuing use of traditional energy sources. This resource strategy significantly reduces GHG emissions compared with SCE's current resource mix. While the change in GHG emissions is not modeled directly in economic development models used in this Plan, the reduction of these GHGs may be captured in indirect effects projected by the models.

Input-Output Modeling (IO Modeling)

IO modeling is a quantitative analysis representing relationships (dependence) between industries in an economy. IO models are based on the implicit assumption that each basic sector has a multiplier, or ripple effect, on the wider economy because each sector purchases goods and services to support that sector. IO modeling estimates the inter-industry transactions and uses those transactions to estimate the economic impacts of any change to the economy.

The IO model used in the Plan, IMPLAN, displays the economic impacts of changes in rates into four categories: employment, labor income, value added, and output. Employment is the number of jobs gained or lost. Labor income involves the increase in salaries and wages for current and newly gained or lost employees. Value added, similar to Gross Domestic Product (GDP), is the payment to labor and capital used in production of a particular industry.

IO models are made up of matrices of multipliers between each industry present in an economy. Each column shows how an industry is dependent on other industries for both its inputs to production and outputs. The tables of multipliers can be used to estimate the effects in changes in spending for various industries, household consumption, or labor income. Both positive and negative impacts can be measured using IO modeling. IO modeling produces results broken down into several categories. Each of these is described below:

- **Direct Effects** – Increased purchases of inputs used to produce final goods and services purchased by residents. Direct effects are the input values in an IO model, or first round effects.
- **Indirect Effects** – Value of inputs used by firms affected by direct effects (inputs). Economic activity that supports direct effects.

- **Induced Effects** – Results of Direct and Indirect effects (calculated using multipliers). Represents economic activity from household spending.
- **Total Effects** – Sum of Direct, Indirect, and Induced effects.
- **Total Output** – Value of all goods and services produced by industries.
- **Value Added** – Total Output less value of inputs, or the Net Benefit/Impact to an economy.
- **Employment** – Number of additional/reduced full time employment resulting from direct effects.

This Plan uses value added and employment figures to represent the total additional economic impact for each Project Alternative. IMPLAN has been used in this Plan to gauge the impacts on the ICP region of retail rate reductions associated with forming ICP. These impacts are discussed in detail below.

Increase in Disposal Income Associated with Rate Reduction Impacts

Exhibit 43 shows the effects $100 million in rate savings will have on the ICP economy. The $100 million rate savings represents the minimum bill savings per year achievable by ICP once in full operation. Direct effects from reduced rates are expected to add 388 jobs. Indirect effects are expected to add about 60 jobs. The induced effects of the project create approximately 98 jobs. In total, approximately 547 jobs are expected to be created in the ICP region. The ICP region is also projected to have a labor income impact of over $24.0 million, a total value added impact of approximately $37.2 million, and an output impact over $54.9 million. Exhibit 45 details the macroeconomics on the ICP region of the anticipated ICP customer bill reductions.

Exhibit 45
$100 Million Rate Savings Effects on ICP Economy

Impact Type	Employment	Labor Income	Total Value Added	Output
Direct Effect	388.0	$18.2 million	$27.7 million	$36.5 million
Indirect Effect	60.3	$2.1 million	$3.5 million	$6.3 million
Induced Effect	98.3	$3.8 million	$7.0 million	$12.1 million
Total Effect	**546.6**	**$24.1 million**	**$37.2 million**	**$54.9 million**

These savings are based on the economic construct that households will spend some share of the increased disposable income on more goods and services. This increased spending on goods and services will then lead to producers either increasing the wages of their current employees or hiring additional employees to handle the increased demand. This in turn will give the employees a larger disposable income which they spend on goods and services and thus repeating the cycle of increased demand.

DER Development Impacts

The economic impacts of DER development are estimated using the Jobs and Economic Development Impact (JEDI) model. JEDI estimates the effects of DER development on construction industries and the local economy. JEDI was initially developed by the National Renewable Energy Laboratory to demonstrate the economic benefits associated with constructing and operating wind and photovoltaic systems in the United States. JEDI has since been expanded to analyze similar economic impacts for various energy sources such as biofuels, coal, concentrating solar power, geothermal, marine and hydrokinetic power, and natural gas. A primary goal of JEDI is that it is being used as a tool for system developers, renewable energy advocates, government officials, decision makers, and others to easily identify the local economic impacts associated with constructing and operating these systems on the economy as a whole, whether through direct and indirect effects.

Users input general information about a particular energy project, such as the project location, the type of system being installed, nameplate capacity, annual operations and maintenance costs, and others. JEDI has default but modifiable data regarding various aspects of each energy system type, such as equipment costs, tax parameters, and labor costs. JEDI then uses the input general information and the data, default or modified, to run calculations on the types of economic effects produced by the proposed project. This model can output projected direct job creation by industry, indirect job and business increases due to the project, projected operation costs, and more.

In order for JEDI to provide information, it must be populated with detailed data for the assumed DER project. Projected system data, type of solar cell, nameplate capacity (kW), and the number of systems. As an example of the macroeconomic activity caused by local DER deployment, this Plan explores the impact of ICP installing of a 50 crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 50 MW. ICP could install a number of larger local solar projects such as the one described above. Exhibit 46 describes the macroeconomic impacts of constructing only one of these local solar projects.

Exhibit 46 Projected Solar Systems Impacts on ICP's Economy			
Description	**Jobs**	**Earnings, $000**	**Output (GDP), $000**
During Construction and Installation Period			
*Project Development and Onsite Labor Impacts			
Construction and Installation Labor	342.5	$22,182	
Construction and Installation Related Services	374.3	$20,007	
Subtotal	716.8	$42,189	$67,620
*Module and Supply Chain Impacts			
Manufacturing Impacts	0.0	$0	$0
Trade (Wholesale and Retail)	79.4	$4,425	$12,887
Finance, Insurance and Real Estate	0.0	$0	$0
Professional Services	53.9	$2,326	$6,908
Other Services	141.4	$15,048	$42,364
Other Sectors	317.1	$10,656	$19,428
Subtotal	591.7	$32,455	$81,587
Induced Impacts	326.7	$13,067	$39,092
Total Impacts	**1,635.3**	**$87,710**	**$188,298**
During Operating Years			
*Onsite Labor Impacts			
PV Project Labor Only	9.2	$555	$555
*Local Revenue and Supply Chain Impacts	2.7	$145	$458
*Induced Impacts	1.9	$74	$221
Total Impacts	**13.8**	**$774**	**$1,235**

Exhibit 46 shows the construction and ongoing effects of building a 50 MW solar power project. It is projected that roughly 1,635 jobs will be created during construction and installation. Of this total, about 719 jobs will be directly involved in construction and installation while roughly 592 jobs will be indirectly involved with the building of the project. Induced impacts of the construction and installation will create approximately 327 jobs. These induced effects may include anything from increased employment in restaurants, retail, education, and others. Overall, the building of this sample 50 MW solar project is projected to create $87 million in earnings and $188 million in output (GDP) in the local economy along with 1,636 jobs during construction and 14 full-time jobs ongoing.

Sensitivity Analysis

The aforementioned economic analysis provides the base case analysis of forming ICP. This base case is predicated on numerous assumptions and estimates that influence the overall results. This section of the Plan will provide the range of impacts that could result from changes in the most significant variables for the ICP scenario. In addition, this section will address risks that cannot be quantified, but should be addressed and mitigated to the maximum amount possible. Each key assumption is discussed, a band of uncertainty is established and ICP's rate impacts associated with factoring in this uncertainty is developed for each key variable.

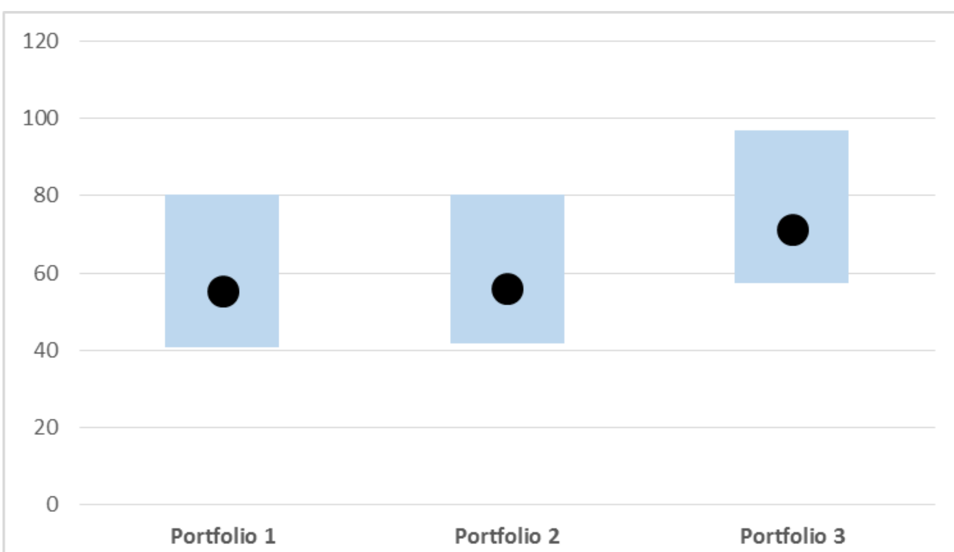
Since resource costs are based on forecast natural gas, wholesale market and renewable market prices, it is prudent to look at the sensitivity of the 20-year levelized cost calculation to fluctuations in these projections. Exhibit 47 below shows a summary of low, base, and high resource costs.

Exhibit 47
Low, Base and High 20-year Levelized Resource Costs ($/MWh)

Case	Market PPA	Portfolio 1 and 2 Renewables	Portfolio 3 Renewables	Natural gas-fired Resources	Local Renewables
Low Case	26.3	32	40	45	45
Base Case	44.3	42	52	60	65
High Case	73.3	62	76	80	85

The 20-year levelized costs of each portfolio has been calculated using the range of resource costs shown above. The base case costs are depicted by the black dots in Exhibit 48.

Exhibit 48
Sensitivity of Portfolio 20-year Levelized Costs



Portfolio 3, which relies on renewable energy purchases to serve all retail loads, has the highest projected costs that range from a low of $57/MWh to a high of $97/MWh. The low case for Portfolio 3 ($57/MWh) is greater than the base case for both Portfolios 1 and 2. The likelihood of solar costs increasing to the point that 20-year levelized costs are near $62/MWh seems unlikely. All signs point to decreases in solar equipment costs on a $/watt basis. There have been significant decreases in solar costs over the past few years. Given the financial incentives targeted at the solar industry as well as the continuing advances in technology, it seems very unlikely that solar costs will increase over the next 10 to 20 years. The study assumes that Production Tax Credits (PTCs) will continue based on the number of times it has been renewed and expanded since 1992.

The potential for market PPA prices to increase to the high case of $73/MWh has a much higher likelihood. Wholesale market prices are dependent on many factors the most notable of which are natural gas prices. Natural gas prices are at historic lows and wholesale market prices have followed. However, natural gas prices are subject to variety of local, national and international forces that could drastically alter the current market place. For one, increased regulation of the natural gas industry with respect to the deployment of fracking technology could cause decreases in natural gas supplies and commensurate increases in natural gas prices. If natural gas prices increased, it is highly likely that electric wholesale market prices would also increase.

When evaluating risks, it is important to note that power supply costs are approximately 81 percent of the total CCA costs, SCE non-bypassable charges account for 13 percent and CCA operating costs account for 6 percent of total CCA revenue requirement.

Loads and Customer Participation Rates

The Plan bases the 20-year load forecasts on expected load growth, load profiles and participation rates. In order to evaluate the potential impact of varying loads, low, medium, and high load forecasts have been developed for the sensitivity analysis. SCE made available load shape profiles by customer class for the entire SCE service area. These load profiles were applied to all customer loads despite the varying climate zones within the County.

Another assumption that can impact the costs of ICP is the overall ICP customer participation rates. This Plan uses a conservative participation rate of 75 percent for residential customers and 65 percent for non-residential customers as its base case. A higher participation rate, such as has been experienced by all of California's operating CCAs to date, will increase energy sales relative to the base case and decrease the fixed costs paid by each customer. On the other hand, a reduced participation rate will increase the fixed costs to ICP participants. Sensitivity to changes in projected loads has been tested for the high and low load forecast scenarios. For the sensitivity analysis, the high case assumes an additional 10 percent participation rate, while the low case assumes the participation rate is reduced by 50 percent. This low participation scenario is intended to explore the case where only some Cities elect to join. The low case assumes a 0 percent growth in energy and customers after 2017, while the high scenario assumes a 5 percent growth in energy and customers.

SCE Rates and Surcharges

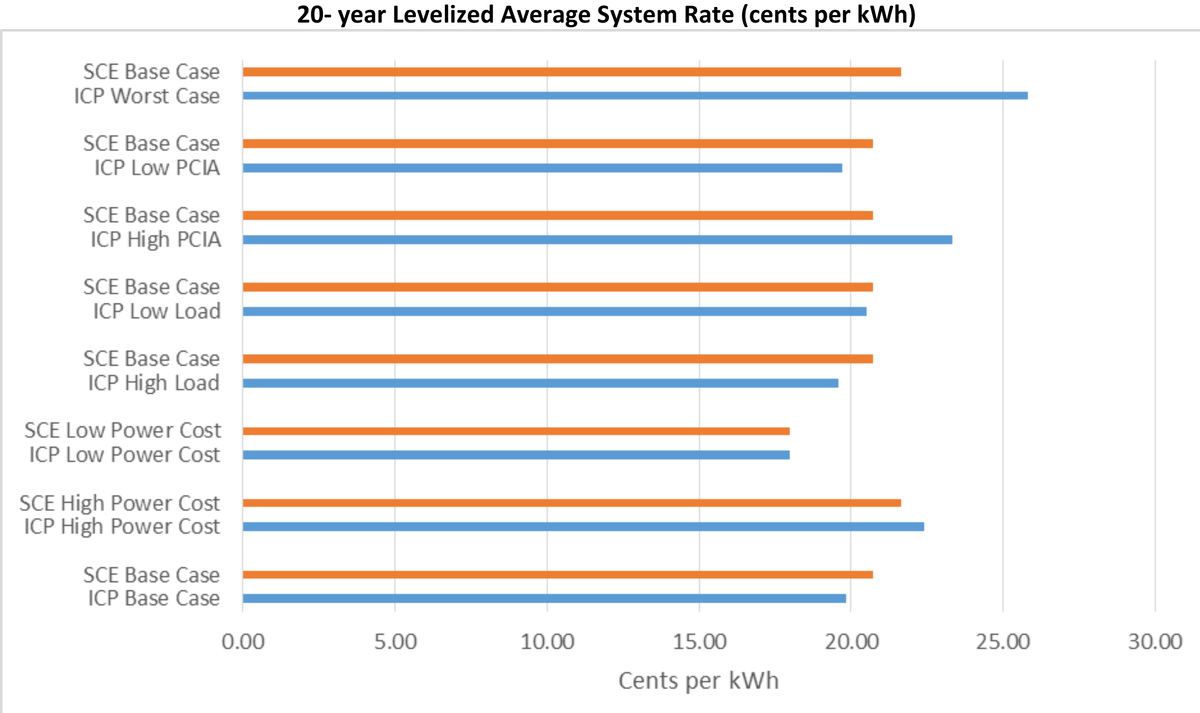
The base case forecast of SCE rates assumes delivery rates increase at 2 percent per year and generation rates increase approximately 2 percent based on the projected market prices and renewable resource growth rates. In addition, SCE's generation cost was modeled in the high and low case by incorporating the expected range of market and renewable resource costs into SCE's portfolio.

The level of the PCIA will impact the cost competiveness of ICP. In order to be cost-effective, ICP power supply costs plus PCIA and other surcharges must be lower than SCE's generation rates. Over time, the PCIA will vary, but it is expected that it will decline as market prices increase. The PCIA reflects SCE's own resources and signed contracts. Once the contracts expire, the related PCIA will disappear. Sensitivity to the PCIA has been modeled in the high case by assuming the PCIA would increase to reflect a historic high of 2.5 cents per kWh and remain flat for the 20-year analysis period. For the low case, it was assumed that the PCIA decreases by 50 percent in year 1 and remains flat for the 20-year analysis period.

Sensitivity Results

Exhibit 49 provides the results of the sensitivity analysis for the 50% Green ICP scenario, which is the most likely portfolio for ICP to pursue. This sensitivity shows that the biggest risk to ICP is if the PCIA increases to historic levels, ICP does not achieve sufficient customer participation or if market prices fall significantly below their current historical low level.

Exhibit 49
50% Green Portfolio Sensitivity
20- year Levelized Average System Rate (cents per kWh)



This sensitivity analysis shows that ICP rate could be greater than SCE rates if:

- The PCIA becomes much larger
- ICP loads are much less than forecast
- Wholesale market prices are much less than current experience

Each of these three scenarios has a low risk of actually occurring. For example, wholesale market prices for natural gas/electricity are at all-time lows. The probability of any significant further lowering of these prices is judged to be very small. The PCIA level should be fairly stable going forward as regulatory remedies are in play to stabilize the PCIA and the CCA vigilance in this area has increased markedly. Finally, this Plan assumes a relatively high customer opt-out percentage (25 percent for residential customers and 35 percent for non-residential customers) compared to the more modest opt-out rates experienced by California's actively operating CCAs, which is closer to 5 percent – 15 percent. It is very unlikely ICP loads will not meet or exceed those assumed in this Plan.

Risks

Regulatory Risks

There are numerous factors that could impact SCE's rates in addition to the market price impacts described above. Regulatory changes, plant or technology retirements or additions, and the long-term impact of the Aliso Canyon leak all can impact SCE rates in the future. However, the impact of these factors is difficult to assess and model quantitatively.

Regulatory issues continue to arise that may impact the competitiveness of ICP. However, California's operating CCAs have worked hard to address any potentially detrimental changes through effective lobbying and technical support.

New legislation can also impact ICP. For example, new legislation that recently affected CCAs are SB 350 and AB 1110. In addition, there are several changes that impact CCAs regarding power supply procurement and contracting. The CCA-specific changes reflected in SB 350 are generally positive, providing for ongoing autonomy with regard to resource planning and procurement. CCAs must be aware, however, of the long term contracting requirement associated with renewable energy procurement.

Regulatory risks also include the potential for utility generation costs to be shifted to non-bypassable and delivery charges. ICP will need to continually monitor and lobby at the Federal, State and local levels to ensure fair and equitable treatment related to non-bypassable charges.

Rate Impacts and Comparisons

The first impact associated with forming ICP will be lower electricity bills for ICP customers. ICP customers should see no obvious changes in electric service other than the lower price and increased procurement of renewable power. Customers will pay the power supply charges set by ICP and no longer pay the higher costs of SCE power supply.

Given this Plan's findings, ICP's rate setting can establish a goal of providing rates that are lower than the equivalent rates offered by SCE even under the 50 percent renewable portfolio. Under the 100 percent renewable portfolio, ICP customers will pay 11 percent less for their power compared to the comparable product offered by SCE. The projected ICP and SCE rates are illustrated in Exhibit 50. For this study, it has been assumed that the projected rate decrease is applied uniformly across all rate classes. Once established, it will be up to the ICP Board and staff to develop rates for each rate class that reflects cost of service.

Exhibit 50
Indicative Rate Comparison in ¢/kWh (First Full Year of Service)

Rate Class	Customer Type	2017 Estimated SCE Bundled Rate*	ICP RPS Bundled Rate	SCE 50% Green Bundled Rate	ICP 50% Green Bundled Rate	SCE 100% Green Bundled Rate	ICP 100% Green Bundled Rate
Residential	Domestic	20.55	19.58	22.30	19.81	24.05	21.79
Residential Care	Domestic	12.22	11.64	13.97	11.78	15.72	12.96
GS-1	Commercial	17.03	16.23	18.78	16.41	20.53	18.06
GS-2	Commercial	16.57	15.79	18.32	15.97	20.07	17.57
GS-3	Industrial	14.71	14.02	16.46	14.18	18.21	15.60
PA-2	Public Authority	13.08	12.46	14.83	12.61	16.58	13.87
PA-3	Public Authority	11.31	10.78	13.06	10.90	14.81	11.99
TOU-8 Secondary	Domestic	13.07	12.45	14.82	12.60	16.57	13.86
TOU-8 Primary	Commercial	11.84	11.28	13.59	11.41	15.34	12.55
TOU-8 Substation	Industrial	7.76	7.39	9.51	7.48	11.26	8.23
Initial Total ICP Rate Savings over Comparable SCE Rates of 50% or 100% Green			4.9%		11.2%		9.4%
Initial Total ICP Rate Savings over SCE's Standard Bundled Rate			4.9%		3.8%		-5.7%

*SCE bundled average rate based on SCE's ERRA 2017 Draft Filing

Exhibit 48 shows the initial rate savings associated with the formation of a CCA. By referencing Appendix B, these initial savings increase after ICP becomes fully functional. The savings by rate schedule after ICP is fully functional are presented below in Exhibit 51.

Exhibit 51 CCA Rate Savings at Fully Functional Operations	
Power Supply Scenario	**Range of Savings***
ICP RPS	4.9% - 5.7%
ICP 50% Renewable	3.8% - 4.5%
ICP 100% Renewable	(5.7%) – (5.0%)

*Note Appendix B for detail.

Once ICP gives notice to SCE that it will commence service, ICP customers will not be responsible for costs associated with SCE's future electricity procurement contracts or power plant investments.[11] This is a distinct advantage to ICP customers as they will now have local control of power supply costs through ICP.

Renewable Energy Impacts

A second consequence of forming ICP will be an increase in the proportion of energy generated and supplied by renewable resources. The Plan includes procurement of renewable energy sufficient to meet 50 percent or more of ICP's electricity needs. The majority of this renewable energy will be met by new renewable resources. By 2020, SCE must procure a minimum of 33 percent of its customers' annual electricity usage from renewable resources due to the State Renewable Portfolio Standard and the Energy Action Plan requirements of the CPUC. In contrast, ICP will target 50 percent renewable by 2018 and these resources will likely be new renewable resources.

Energy Efficiency Programs

A third consequence of forming ICP could be an increase in energy efficiency program investments and activities. The existing energy efficiency programs administered by SCE are not expected to change as a result of forming ICP. ICP customers will continue to pay the public goods charges to SCE which funds energy efficiency programs for all customers, regardless of supplier. The energy efficiency programs ultimately planned for ICP will be in addition to the level of investment that would continue in the absence of ICP. Thus, ICP has the potential for increased energy investment and savings with an attendant further reduction in emissions due to expanded energy efficiency programs.

[11] CCAs may be liable for a share of unbundled stranded costs from new generation, but would then receive associated Resource Adequacy credits.

Economic Development Impacts

The fourth consequence of forming ICP will be enhanced local economic development. The analyses contained in this Plan has focused primarily on the direct effects of this formation. However, in addition to direct effects, indirect economic effects are also encountered. The indirect effects of creating ICP include the effects of increased local investments, increased disposable income due to bill savings and improved environmental and health conditions.

Exhibit 49 shows the effects $100 million in rate savings will have on the ICP economy. The $100 million rate savings represents the minimum bill savings per year achievable by ICP once in full operation. Direct effects from reduced rates are expected to add 388 jobs. Indirect effects are expected to add about 60 jobs. The induced effects of the project create approximately 98 jobs. In total, approximately 547 jobs are expected to be created in the ICP region. The ICP region is also projected to have a labor income impact of over $24.0 million, a total value added impact of approximately $37.2 million, and an output impact over $54.9 million. Exhibit 52 details the macroeconomics on the ICP region of the anticipated ICP customer bill reductions.

Exhibit 52
$100 Million Rate Savings Effects on ICP Economy

Impact Type	Employment	Labor Income	Total Value Added	Output
Direct Effect	388.0	$18.2 million	$27.7 million	$36.5 million
Indirect Effect	60.3	$2.1 million	$3.5 million	$6.3 million
Induced Effect	98.3	$3.8 million	$7.0 million	$12.1 million
Total Effect	**546.6**	**$24.1 million**	**$37.2 million**	**$54.9 million**

These savings are based on the economic construct that households will spend some share of the increased disposable income on more goods and services. This increased spending on goods and services will then lead to producers either increasing the wages of their current employees or hiring additional employees to handle the increased demand. This in turn will give the employees a larger disposable income which they spend on goods and services and thus repeating the cycle of increased demand.

In addition to increased economic activity due to electric bill savings, potential local projects can also create job and economic growth in the local economy. As an example of the macroeconomic activity caused by local DER deployment, this Plan assumes the installation of fifty crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 50 MW. Overall, the building of this one solar project is projected to create $87 million in earnings and $188 million in output (GDP) in the local economy along with 1,636 jobs during construction and 14 full-time jobs ongoing. It is anticipated that ICP will ultimately install a number of larger local solar projects such as the one described.

Impact of Resource Plan on Greenhouse Gas (GHG) Emissions

The last consequence of forming ICP would be environmental benefits. The share of renewable power in SCE's power supply portfolio is currently 28 percent[12] and is scheduled to shift to 33 percent by 2020. Assuming ICP adopts a base case 50 percent RPS target at start-up, GHG emissions reductions attributable to ICP operations in 2019 will range from 1.33 to 2.34 million metric tons CO_2 equivalent (CO_2e) per year relative to SCE's projected resource mix over the same period. Exhibit 53 details these reductions.

Exhibit 53
Baseline Comparison of GHG Reduction by ICP by 2018

	ICP	CVAG	SANBAG	WRCOG
Forecast Renewables (50% Renewables) ICP (MWH) – Phase 2	7,533	916	4,184	2,433
ICP RPS (MWH) – Phase 2	4,219	513	2,343	1,362
Additional Green Power	3,315	403	1,841	1,070
CO2 reduction – Low (Metric Tons of CO_2e)	1.33	0.16	0.74	0.43
CO2 reduction – High (Metric tons of CO_2e)	2.34	0.28	1.30	0.76

The reduction in GHG emissions associated with ICP operations is significant. This amount of reduced emissions represents a reduction in the emissions from the in-State generation resources of 2.6 to 4.6 percent.

Summary

This Plan concludes that the formation of ICP in the service areas of CVAG, SANBAG and WRCOG is financially prudent and will yield considerable benefits for ICP's residents and businesses. These benefits include at least a 3.8 percent lower rate for electricity (assuming the 50 percent renewable scenario) than is charged by SCE while receiving nearly twice the amount of renewable energy. With the achievement of Phase 2 level of operations, ICP will reduce GHG emissions by as much as 2.34 million metric tons of CO_2e per year, add over 500 jobs, generate over $54 million in additional GDP, and give residents and businesses local control over their power supply and energy efficiency programs. Even with these stated rate savings, significant funding is still generated to support new programs, local DER and/or additional rate savings to the CCA's customers.

There are risks associated with a CCA which are manageable. On balance, the formation of a CCA for CVAG, SANBAG and WRCOG is financially feasible and results in beneficial environmental/economic impacts. A joint CCA with common back office functions and local

[12] http://www.cpuc.ca.gov/RPS_Homepage/

options for program development is the most economical operational option and is recommended. A more “hands on” operating model is also recommended.

Appendix A – Cities/Counties Evaluating CCA Feasibility

	CCA Name	Service Area	Start Date	IOU
Operational				
	Marin Clean Energy	Marin County, Napa County, part of Contra Costa and Solano Counties	May 2010	PG&E
	Sonoma Clean Power	Sonoma County	May 2014	PG&E
	Lancaster Choice Energy	City of Lancaster	May 2015	SCE
	Clean Power San Francisco	City of San Francisco	May 2016	PG&E
	Peninsula Clean Energy	San Mateo County	October 2016	PG&E
Exploring/In Process				
	Redwood Coast Energy Authority	Humboldt County	May 2017	PG&E
	East Bay Community Energy	Alameda County		PG&E
	TBD	Butte County		PG&E
	TBD	City of San Jose		PG&E
	TBD	Contra Costa County		PG&E
	TBD	Humboldt County		PG&E
	LA Community Choice Energy	LA County		SCE
	TBD	Mendocino County		PG&E
	TBD	Monterey County		PG&E
	TBD	Placer County		PG&E
	TBD	Riverside County		SCE
	TBD	San Benito County		PG&E
	TBD	San Bernardino County		SCE
	TBD	San Diego County		SDG&E
	TBD	San Luis Obispo County		PG&E
	TBD	Santa Barbara County		SCE/PG&E
	Silicon Valley Clean Energy	Santa Clara County	April 2017	PG&E
	TBD	Santa Cruz County		PG&E

Appendix B – Financial Proforma Analyses

ICP Community Choice Aggregation
Financial Proforma
Portfolio RPS

Load Data	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts												
Domestic	0	6,563	857,965	867,660	877,464	887,379	897,407	907,548	917,803	928,174	938,662	949,269
Commercial	0	56,243	88,543	89,543	90,555	91,578	92,613	93,660	94,718	95,788	96,871	97,965
Industrial	0	0	457	462	467	472	478	483	488	494	500	505
Lighting & Traffic Control	0	6,801	11,029	11,154	11,280	11,407	11,536	11,666	11,798	11,931	12,066	12,203
Agricultural	0	63	3,146	3,182	3,218	3,254	3,291	3,328	3,366	3,404	3,442	3,481
Total Customers	0	69,669	961,139	972,000	982,983	994,091	1,005,324	1,016,685	1,028,173	1,039,791	1,051,541	1,063,423
Energy Sales (MWh)												
Domestic	0	95	6,882,813	6,960,589	7,039,244	7,118,787	7,199,230	7,280,581	7,362,851	7,446,052	7,530,192	7,615,283
Commercial	0	136,839	4,018,999	4,064,414	4,110,342	4,156,789	4,203,760	4,251,263	4,299,302	4,347,884	4,397,015	4,446,702
Industrial	0	0	2,640,375	2,670,212	2,700,385	2,730,899	2,761,759	2,792,966	2,824,527	2,856,444	2,888,722	2,921,365
Lighting & Traffic Control	0	44,238	118,280	119,616	120,968	122,335	123,717	125,115	126,529	127,959	129,405	130,867
Agricultural	0	21,702	546,909	553,089	559,339	565,659	572,051	578,515	585,052	591,663	598,349	605,111
Total Energy Sales (MWh)	0	202,873	14,207,376	14,367,920	14,530,277	14,694,469	14,860,517	15,028,441	15,198,262	15,370,003	15,543,684	15,719,327
CCE Operating Costs	**2017 Jan - June**	**2017 July - Dec**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Power Supply	$0	$9,973,595	$707,645,195	$733,748,921	$765,582,666	$792,385,834	$818,332,855	$846,659,904	$874,361,323	$903,459,966	$931,873,882	$961,012,268
Billing & Data Management	$0	$731,529	$14,414,632	$14,577,517	$14,742,243	$14,908,830	$15,077,300	$15,247,674	$15,419,972	$15,594,218	$15,770,433	$15,948,639
SCE Fees	$250,165	$3,574,050	$8,197,628	$4,781,534	$4,835,564	$4,890,204	$4,945,462	$5,001,345	$5,057,859	$5,115,012	$5,172,810	$5,231,261
Technical Services	$620,000	$740,000	$1,310,000	$1,356,600	$1,383,732	$1,411,407	$1,439,635	$1,468,427	$1,497,796	$1,527,752	$1,558,307	$1,589,473
Staffing	$90,000	$970,000	$2,488,333	$2,632,212	$2,684,856	$2,738,553	$2,793,324	$2,849,191	$2,906,175	$2,964,298	$3,023,584	$3,084,056
General & Administrative expenses	$90,000	$260,000	$350,000	$306,000	$312,120	$318,362	$399,730	$356,224	$337,849	$344,606	$351,498	$508,528
Debt Service (CCE Bonds & Start-up Costs)	$0	$2,341,764	$19,327,411	$19,327,411	$19,327,411	$19,327,411	$16,985,647	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883
Contribution to Annual Reserves	$0	$9,934,999	$55,443,412	$62,337,327	$66,632,200	$35,097,145	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$35,097,145	$75,906,074	$82,489,758	$86,198,044	$90,078,875	$93,855,938	$97,582,406
Start-Up Capital	$0	($20,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$5,251	$101,566	$4,370,491	$4,489,833	$4,654,354	$4,794,622	$4,919,582	$4,649,509	$4,790,060	$4,937,722	$5,082,168	$5,231,049
Total Operating Costs	$1,055,416	$8,627,503	$813,547,104	$843,557,356	$880,155,147	$910,969,515	$940,799,610	$973,365,914	$1,005,212,961	$1,038,666,330	$1,071,332,502	$1,104,831,564
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$1,055,416	$8,627,503	$813,547,104	$843,557,356	$880,155,147	$910,969,515	$940,799,610	$973,365,914	$1,005,212,961	$1,038,666,330	$1,071,332,502	$1,104,831,564
Average CCE Rate ($/kWh)		$0.0477	$0.0573	$0.0587	$0.0606	$0.0620	$0.0633	$0.0648	$0.0661	$0.0676	$0.0689	$0.0703
Average SCE Generation Rate ($/kWh)		$0.0575	$0.0690	$0.0707	$0.0730	$0.0747	$0.0763	$0.0780	$0.0797	$0.0814	$0.0830	$0.0847
Total CCE Charges												
SCE Non-bypassable Charges	$0	$1,722,191	$120,365,021	$121,236,384	$122,002,252	$122,943,738	$123,942,523	$43,675,101	$43,787,237	$43,894,603	$44,039,228	$44,191,735
CCE Revenue Requirement	$1,055,416	$8,627,503	$813,547,104	$843,557,356	$880,155,147	$910,969,515	$940,799,610	$973,365,914	$1,005,212,961	$1,038,666,330	$1,071,332,502	$1,104,831,564
Total CCE Generation Revenue Requirement	$1,055,416	$10,349,694	$933,912,125	$964,793,740	$1,002,157,399	$1,033,913,253	$1,064,742,133	$1,017,041,015	$1,049,000,198	$1,082,560,933	$1,115,371,730	$1,149,023,298
Bundled SCE Revenues	$0	$32,500,966	$2,492,090,079	$2,575,911,573	$2,669,172,535	$2,757,015,564	$2,845,271,634	$2,938,473,662	$3,032,510,433	$3,130,237,483	$3,228,826,383	$3,330,286,114
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$0	$31,143,060	$2,369,016,113	$2,446,694,352	$2,532,347,501	$2,613,932,972	$2,696,180,352	$2,782,784,660	$2,870,410,677	$2,961,393,199	$3,053,436,062	$3,148,187,047
Savings	**$0**	**$1,357,906**	**$123,073,966**	**$129,217,221**	**$136,825,034**	**$143,082,591**	**$149,091,281**	**$155,689,002**	**$162,099,755**	**$168,844,284**	**$175,390,321**	**$182,099,067**
Percent Savings		**4.2%**	**4.9%**	**5.0%**	**5.1%**	**5.2%**	**5.2%**	**5.3%**	**5.3%**	**5.4%**	**5.4%**	**5.5%**
Cumulative Reserves		$9,934,999	$65,378,411	$127,715,739	$194,347,939	$264,542,229	$340,448,303	$422,938,061	$509,136,105	$599,214,980	$693,070,918	$790,653,324
Reserve Target		$219,617,178										

ICP Community Choice Aggregation
Financial Proforma
Portfolio RPS

Load Data	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Customer Accounts									
Domestic	959,996	970,844	981,814	992,909	1,004,129	1,015,475	1,026,950	1,038,555	1,050,291
Commercial	99,072	100,192	101,324	102,469	103,627	104,798	105,982	107,180	108,391
Industrial	511	517	523	528	534	540	547	553	0
Lighting & Traffic Control	12,341	12,480	12,621	12,764	12,908	13,054	13,201	13,350	0
Agricultural	3,520	3,560	3,601	3,641	3,682	3,724	3,766	3,809	0
Total Customers	1,075,440	1,087,593	1,099,882	1,112,311	1,124,880	1,137,591	1,150,446	1,163,446	1,158,681
Energy Sales (MWh)									
Domestic	7,701,336	7,788,361	7,876,369	7,965,372	8,055,381	8,146,407	8,238,461	8,331,556	8,425,703
Commercial	4,496,949	4,547,765	4,599,155	4,651,125	4,703,683	4,756,834	4,810,587	4,864,946	4,919,920
Industrial	2,954,376	2,987,760	3,021,522	3,055,665	3,090,194	3,125,114	3,160,427	3,196,140	3,232,257
Lighting & Traffic Control	132,346	133,842	135,354	136,884	138,430	139,995	141,576	143,176	144,794
Agricultural	611,948	618,863	625,857	632,929	640,081	647,314	654,628	662,026	669,507
Total Energy Sales (MWh)	15,896,956	16,076,591	16,258,257	16,441,975	16,627,769	16,815,663	17,005,680	17,197,844	17,392,180
CCE Operating Costs	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Power Supply	$990,057,690	$1,021,103,132	$1,046,331,881	$1,082,093,730	$1,114,321,376	$1,149,294,280	$1,187,432,515	$1,226,128,522	$1,267,265,121
Billing & Data Management	$16,128,858	$16,311,114	$16,495,430	$16,681,828	$16,870,333	$17,060,968	$17,253,757	$17,448,724	$17,645,895
SCE Fees	$5,290,374	$5,350,154	$5,410,609	$5,471,748	$5,533,577	$5,596,105	$5,659,340	$5,723,290	$5,787,961
Technical Services	$1,621,263	$1,653,688	$1,686,762	$1,720,497	$1,754,907	$1,790,005	$1,825,805	$1,862,321	$1,899,568
Staffing	$3,145,737	$3,208,652	$3,272,825	$3,338,281	$3,405,047	$3,473,148	$3,542,611	$3,613,463	$3,685,732
General & Administrative expenses	$415,698	$373,012	$380,473	$388,082	$470,844	$428,761	$411,836	$420,072	$428,474
Debt Service (CCE Bonds & Start-up Costs)	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883
Contribution to Annual Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs	$101,541,893	$105,735,775	$109,032,602	$113,848,978	$118,073,390	$122,815,616	$127,985,610	$133,205,901	$138,774,019
Start-Up Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$5,378,352	$5,535,854	$5,665,131	$5,846,319	$6,010,631	$6,187,959	$6,381,142	$6,577,340	$6,785,717
Total Operating Costs	$1,138,223,748	$1,173,915,263	$1,202,919,595	$1,244,033,346	$1,281,083,987	$1,321,290,724	$1,365,136,498	$1,409,623,515	$1,456,916,370
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$1,138,223,748	$1,173,915,263	$1,202,919,595	$1,244,033,346	$1,281,083,987	$1,321,290,724	$1,365,136,498	$1,409,623,515	$1,456,916,370
Average CCE Rate ($/kWh)	$0.0716	$0.0730	$0.0740	$0.0757	$0.0770	$0.0786	$0.0803	$0.0820	$0.0838
Average SCE Generation Rate ($/kWh)	$0.0863	$0.0880	$0.0891	$0.0912	$0.0928	$0.0947	$0.0967	$0.0988	$0.1009
Total CCE Charges									
SCE Non-bypassable Charges	$44,366,859	$44,527,161	$44,804,342	$44,925,839	$45,126,238	$45,304,664	$45,458,584	$45,627,682	$45,786,716
CCE Revenue Requirement	$1,138,223,748	$1,173,915,263	$1,202,919,595	$1,244,033,346	$1,281,083,987	$1,321,290,724	$1,365,136,498	$1,409,623,515	$1,456,916,370
Total CCE Generation Revenue Requirement	$1,182,590,606	$1,218,442,424	$1,247,723,937	$1,288,959,185	$1,326,210,225	$1,366,595,388	$1,410,595,082	$1,455,251,198	$1,502,703,086
Bundled SCE Revenues	$3,433,543,297	$3,541,557,705	$3,643,564,853	$3,762,275,864	$3,878,272,416	$4,000,321,101	$4,129,074,697	$4,260,994,562	$4,398,764,102
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$3,244,779,991	$3,345,644,391	$3,441,988,073	$3,552,399,692	$3,661,007,958	$3,774,999,954	$3,894,927,011	$4,017,904,175	$4,146,146,261
Savings	**$188,763,307**	**$195,913,314**	**$201,576,780**	**$209,876,172**	**$217,264,458**	**$225,321,147**	**$234,147,686**	**$243,090,387**	**$252,617,842**
Percent Savings	**5.5%**	**5.5%**	**5.5%**	**5.6%**	**5.6%**	**5.6%**	**5.7%**	**5.7%**	**5.7%**
Cumulative Reserves	$892,195,217	$997,930,992	$1,106,963,594	$1,220,812,571	$1,338,885,961	$1,461,701,577	$1,589,687,187	$1,722,893,088	$1,861,667,107
Reserve Target									

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Load Data	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts												
Domestic	0	6,563	857,965	867,660	877,464	887,379	897,407	907,548	917,803	928,174	938,662	949,269
Commercial	0	56,243	88,543	89,543	90,555	91,578	92,613	93,660	94,718	95,788	96,871	97,965
Industrial	0	0	457	462	467	472	478	483	488	494	500	505
Lighting & Traffic Control	0	6,801	11,029	11,154	11,280	11,407	11,536	11,666	11,798	11,931	12,066	12,203
Agricultural	0	63	3,146	3,182	3,218	3,254	3,291	3,328	3,366	3,404	3,442	3,481
Total Customers	0	69,669	961,139	972,000	982,983	994,091	1,005,324	1,016,685	1,028,173	1,039,791	1,051,541	1,063,423
Energy Sales (MWh)												
Domestic	0	95	6,882,813	6,960,589	7,039,244	7,118,787	7,199,230	7,280,581	7,362,851	7,446,052	7,530,192	7,615,283
Commercial	0	136,839	4,018,999	4,064,414	4,110,342	4,156,789	4,203,760	4,251,263	4,299,302	4,347,884	4,397,015	4,446,702
Industrial	0	0	2,640,375	2,670,212	2,700,385	2,730,899	2,761,759	2,792,966	2,824,527	2,856,444	2,888,722	2,921,365
Lighting & Traffic Control	0	44,238	118,280	119,616	120,968	122,335	123,717	125,115	126,529	127,959	129,405	130,867
Agricultural	0	21,702	546,909	553,089	559,339	565,659	572,051	578,515	585,052	591,663	598,349	605,111
Total Energy Sales (MWh)	0	202,873	14,207,376	14,367,920	14,530,277	14,694,469	14,860,517	15,028,441	15,198,262	15,370,003	15,543,684	15,719,327

CCE Operating Costs	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Power Supply	$0	$10,381,996	$738,881,822	$759,553,192	$780,672,276	$803,406,868	$826,270,323	$850,038,727	$874,560,745	$900,023,370	$926,876,984	$954,872,057
Billing & Data Management	$0	$731,529	$14,414,632	$14,577,517	$14,742,243	$14,908,830	$15,077,300	$15,247,674	$15,419,972	$15,594,218	$15,770,433	$15,948,639
SCE Fees	$250,165	$3,574,050	$8,197,628	$4,781,534	$4,835,564	$4,890,204	$4,945,462	$5,001,345	$5,057,859	$5,115,012	$5,172,810	$5,231,261
Technical Services	$620,000	$740,000	$1,310,000	$1,356,600	$1,383,732	$1,411,407	$1,439,635	$1,468,427	$1,497,796	$1,527,752	$1,558,307	$1,589,473
Staffing	$90,000	$970,000	$2,488,333	$2,632,212	$2,684,856	$2,738,553	$2,793,324	$2,849,191	$2,906,175	$2,964,298	$3,023,584	$3,084,056
General & Administrative expenses	$90,000	$260,000	$350,000	$306,000	$312,120	$318,362	$399,730	$356,224	$337,849	$344,606	$351,498	$508,528
Debt Service (CCE Bonds & Start-up Costs)	$0	$2,341,764	$19,327,411	$19,327,411	$19,327,411	$19,327,411	$16,985,647	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883
Contribution to Annual Reserves	$0	$9,874,541	$53,455,920	$66,894,060	$83,279,978	$46,022,380	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$46,022,380	$101,933,723	$114,275,941	$122,330,624	$131,074,810	$137,600,681	$143,686,990
Start-Up Capital	$0	($20,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$5,251	$103,608	$4,526,674	$4,618,854	$4,729,802	$4,849,727	$4,959,270	$4,666,403	$4,791,058	$4,920,539	$5,057,184	$5,200,348
Total Operating Costs	$1,055,416	$8,977,488	$842,952,421	$874,047,381	$911,967,983	$943,896,124	$974,804,415	$1,008,547,815	$1,041,545,960	$1,076,208,487	$1,110,055,364	$1,144,765,235
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$1,055,416	$8,977,488	$842,952,421	$874,047,381	$911,967,983	$943,896,124	$974,804,415	$1,008,547,815	$1,041,545,960	$1,076,208,487	$1,110,055,364	$1,144,765,235
Average CCE Rate ($/kWh)		$0.0495	$0.0593	$0.0608	$0.0628	$0.0642	$0.0656	$0.0671	$0.0685	$0.0700	$0.0714	$0.0728
Average SCE Generation Rate ($/kWh)		$0.0575	$0.0690	$0.0707	$0.0730	$0.0747	$0.0763	$0.0780	$0.0797	$0.0814	$0.0830	$0.0847
Total CCE Charges												
SCE Non-bypassable Charges	$0	$1,722,191	$120,365,021	$121,236,384	$122,002,252	$122,943,738	$123,942,523	$43,675,101	$43,787,237	$43,894,603	$44,039,228	$44,191,735
CCE Revenue Requirement	$1,055,416	$8,977,488	$842,952,421	$874,047,381	$911,967,983	$943,896,124	$974,804,415	$1,008,547,815	$1,041,545,960	$1,076,208,487	$1,110,055,364	$1,144,765,235
Total CCE Generation Revenue Requirement	$1,055,416	$10,699,679	$963,317,442	$995,283,765	$1,033,970,236	$1,066,839,862	$1,098,746,938	$1,052,222,916	$1,085,333,197	$1,120,103,090	$1,154,094,592	$1,188,956,969
Bundled SCE Revenues	$0	$32,500,966	$2,492,090,079	$2,575,911,573	$2,669,172,535	$2,757,015,564	$2,845,271,634	$2,938,473,662	$3,032,510,433	$3,130,237,483	$3,228,826,383	$3,330,286,114
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$0	$31,493,045	$2,398,421,430	$2,477,184,377	$2,564,160,338	$2,646,859,581	$2,730,185,158	$2,817,966,561	$2,906,743,676	$2,998,935,356	$3,092,158,924	$3,188,120,717
Savings	**$0**	**$1,007,921**	**$93,668,649**	**$98,727,196**	**$105,012,197**	**$110,155,982**	**$115,086,476**	**$120,507,101**	**$125,766,757**	**$131,302,128**	**$136,667,459**	**$142,165,397**
Percent Savings		**3.1%**	**3.8%**	**3.8%**	**3.9%**	**4.0%**	**4.0%**	**4.1%**	**4.1%**	**4.2%**	**4.2%**	**4.3%**
Cumulative Reserves		$9,874,541	$63,330,461	$130,224,521	$213,504,499	$305,549,260	$407,482,983	$521,758,924	$644,089,548	$775,164,358	$912,765,040	$1,056,452,029
Reserve Target		$227,465,380										

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Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	959,996	970,844	981,814	992,909	1,004,129	1,015,475	1,026,950	1,038,555	1,050,291
Commercial	99,072	100,192	101,324	102,469	103,627	104,798	105,982	107,180	108,391
Industrial	511	517	523	528	534	540	547	553	0
Lighting & Traffic Control	12,341	12,480	12,621	12,764	12,908	13,054	13,201	13,350	0
Agricultural	3,520	3,560	3,601	3,641	3,682	3,724	3,766	3,809	0
Total Customers	1,075,440	1,087,593	1,099,882	1,112,311	1,124,880	1,137,591	1,150,446	1,163,446	1,158,681
Energy Sales (MWh)									
Domestic	7,701,336	7,788,361	7,876,369	7,965,372	8,055,381	8,146,407	8,238,461	8,331,556	8,425,703
Commercial	4,496,949	4,547,765	4,599,155	4,651,125	4,703,683	4,756,834	4,810,587	4,864,946	4,919,920
Industrial	2,954,376	2,987,760	3,021,522	3,055,665	3,090,194	3,125,114	3,160,427	3,196,140	3,232,257
Lighting & Traffic Control	132,346	133,842	135,354	136,884	138,430	139,995	141,576	143,176	144,794
Agricultural	611,948	618,863	625,857	632,929	640,081	647,314	654,628	662,026	669,507
Total Energy Sales (MWh)	15,896,956	16,076,591	16,258,257	16,441,975	16,627,769	16,815,663	17,005,680	17,197,844	17,392,180

CCE Operating Costs	2028	2029	2030	2031	2032	2033	2034	2035	2036
Power Supply	$983,522,942	$1,013,839,299	$1,046,331,881	$1,082,093,730	$1,114,321,376	$1,149,294,280	$1,187,432,515	$1,226,128,522	$1,267,265,121
Billing & Data Management	$16,128,858	$16,311,114	$16,495,430	$16,681,828	$16,870,333	$17,060,968	$17,253,757	$17,448,724	$17,645,895
SCE Fees	$5,290,374	$5,350,154	$5,410,609	$5,471,748	$5,533,577	$5,596,105	$5,659,340	$5,723,290	$5,787,961
Technical Services	$1,621,263	$1,653,688	$1,686,762	$1,720,497	$1,754,907	$1,790,005	$1,825,805	$1,862,321	$1,899,568
Staffing	$3,145,737	$3,208,652	$3,272,825	$3,338,281	$3,405,047	$3,473,148	$3,542,611	$3,613,463	$3,685,732
General & Administrative expenses	$415,698	$373,012	$380,473	$388,082	$470,844	$428,761	$411,836	$420,072	$428,474
Debt Service (CCE Bonds & Start-up Costs)	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883
Contribution to Annual Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs	$149,249,933	$155,466,599	$152,511,623	$158,814,038	$164,377,630	$170,573,112	$177,327,893	$184,156,148	$191,433,647
Start-Up Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$5,345,678	$5,499,535	$5,665,131	$5,846,319	$6,010,631	$6,187,959	$6,381,142	$6,577,340	$6,785,717
Total Operating Costs	$1,179,364,365	$1,216,345,935	$1,246,398,616	$1,288,998,407	$1,327,388,228	$1,369,048,220	$1,414,478,781	$1,460,573,763	$1,509,575,998
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$1,179,364,365	$1,216,345,935	$1,246,398,616	$1,288,998,407	$1,327,388,228	$1,369,048,220	$1,414,478,781	$1,460,573,763	$1,509,575,998
Average CCE Rate ($/kWh)	$0.0742	$0.0757	$0.0767	$0.0784	$0.0798	$0.0814	$0.0832	$0.0849	$0.0868
Average SCE Generation Rate ($/kWh)	$0.0863	$0.0880	$0.0891	$0.0912	$0.0928	$0.0947	$0.0967	$0.0988	$0.1009
Total CCE Charges									
SCE Non-bypassable Charges	$44,366,859	$44,527,161	$44,804,342	$44,925,839	$45,126,238	$45,304,664	$45,458,584	$45,627,682	$45,786,716
CCE Revenue Requirement	$1,179,364,365	$1,216,345,935	$1,246,398,616	$1,288,998,407	$1,327,388,228	$1,369,048,220	$1,414,478,781	$1,460,573,763	$1,509,575,998
Total CCE Generation Revenue Requirement	$1,223,731,224	$1,260,873,096	$1,291,202,959	$1,333,924,246	$1,372,514,466	$1,414,352,884	$1,459,937,365	$1,506,201,445	$1,555,362,714
Bundled SCE Revenues	$3,433,543,297	$3,541,557,705	$3,643,564,853	$3,762,275,864	$3,878,272,416	$4,000,321,101	$4,129,074,697	$4,260,994,562	$4,398,764,102
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$3,285,920,608	$3,388,075,063	$3,485,467,095	$3,597,364,753	$3,707,312,199	$3,822,757,450	$3,944,269,294	$4,068,854,422	$4,198,805,888
Savings	**$147,622,689**	**$153,482,642**	**$158,097,758**	**$164,911,111**	**$170,960,217**	**$177,563,651**	**$184,805,403**	**$192,140,140**	**$199,958,214**
Percent Savings	**4.3%**	**4.3%**	**4.3%**	**4.4%**	**4.4%**	**4.4%**	**4.5%**	**4.5%**	**4.5%**
Cumulative Reserves	$1,205,701,962	$1,361,168,561	$1,513,680,184	$1,672,494,222	$1,836,871,852	$2,007,444,965	$2,184,772,858	$2,368,929,006	$2,560,362,653
Reserve Target									

ICP Community Choice Aggregation
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Portfolio -100% Renewable

Load Data	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts												
Domestic	0	6,563	857,965	867,660	877,464	887,379	897,407	907,548	917,803	928,174	938,662	949,269
Commercial	0	56,243	88,543	89,543	90,555	91,578	92,613	93,660	94,718	95,788	96,871	97,965
Industrial	0	0	457	462	467	472	478	483	488	494	500	505
Lighting & Traffic Control	0	6,801	11,029	11,154	11,280	11,407	11,536	11,666	11,798	11,931	12,066	12,203
Agricultural	0	63	3,146	3,182	3,218	3,254	3,291	3,328	3,366	3,404	3,442	3,481
Total Customers	0	69,669	961,139	972,000	982,983	994,091	1,005,324	1,016,685	1,028,173	1,039,791	1,051,541	1,063,423
Energy Sales (MWh)												
Domestic	0	95	6,882,813	6,960,589	7,039,244	7,118,787	7,199,230	7,280,581	7,362,851	7,446,052	7,530,192	7,615,283
Commercial	0	136,839	4,018,999	4,064,414	4,110,342	4,156,789	4,203,760	4,251,263	4,299,302	4,347,884	4,397,015	4,446,702
Industrial	0	0	2,640,375	2,670,212	2,700,385	2,730,899	2,761,759	2,792,966	2,824,527	2,856,444	2,888,722	2,921,365
Lighting & Traffic Control	0	44,238	118,280	119,616	120,968	122,335	123,717	125,115	126,529	127,959	129,405	130,867
Agricultural	0	21,702	546,909	553,089	559,339	565,659	572,051	578,515	585,052	591,663	598,349	605,111
Total Energy Sales (MWh)	0	202,873	14,207,376	14,367,920	14,530,277	14,694,469	14,860,517	15,028,441	15,198,262	15,370,003	15,543,684	15,719,327

CCE Operating Costs	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Power Supply	$0	$13,812,233	$965,273,392	$988,855,853	$1,013,033,065	$1,038,816,390	$1,064,978,225	$1,092,187,159	$1,120,292,984	$1,149,278,806	$1,179,609,155	$1,211,057,134
Billing & Data Management	$0	$731,529	$14,414,632	$14,577,517	$14,742,243	$14,908,830	$15,077,300	$15,247,674	$15,419,972	$15,594,218	$15,770,433	$15,948,639
SCE Fees	$250,165	$3,574,050	$8,197,628	$4,781,534	$4,835,564	$4,890,204	$4,945,462	$5,001,345	$5,057,859	$5,115,012	$5,172,810	$5,231,261
Technical Services	$620,000	$740,000	$1,310,000	$1,356,600	$1,383,732	$1,411,407	$1,439,635	$1,468,427	$1,497,796	$1,527,752	$1,558,307	$1,589,473
Staffing	$90,000	$970,000	$2,488,333	$2,632,212	$2,684,856	$2,738,553	$2,793,324	$2,849,191	$2,906,175	$2,964,298	$3,023,584	$3,084,056
General & Administrative expenses	$90,000	$260,000	$350,000	$306,000	$312,120	$318,362	$399,730	$356,224	$337,849	$344,606	$351,498	$508,528
Debt Service (CCE Bonds & Start-up Costs)	$0	$2,341,764	$19,327,411	$19,327,411	$19,327,411	$19,327,411	$16,985,647	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883
Contribution to Annual Reserves	$0	$9,227,034	$61,174,927	$80,365,085	$104,260,078	$59,435,532	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$59,435,532	$134,070,724	$152,371,971	$166,033,712	$180,910,349	$193,387,742	$205,690,356
Start-Up Capital	$0	($20,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$5,251	$120,759	$5,658,632	$5,765,368	$5,891,606	$6,026,774	$6,152,809	$5,877,145	$6,019,719	$6,166,816	$6,320,844	$6,481,274
Total Operating Costs	$1,055,416	$11,777,368	$1,078,194,957	$1,117,967,580	$1,166,470,677	$1,207,308,996	$1,246,842,857	$1,290,003,019	$1,332,209,949	$1,376,545,739	$1,419,838,256	$1,464,234,602
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$1,055,416	$11,777,368	$1,078,194,957	$1,117,967,580	$1,166,470,677	$1,207,308,996	$1,246,842,857	$1,290,003,019	$1,332,209,949	$1,376,545,739	$1,419,838,256	$1,464,234,602
Average CCE Rate ($/kWh)		$0.0633	$0.0759	$0.0778	$0.0803	$0.0822	$0.0839	$0.0858	$0.0877	$0.0896	$0.0913	$0.0931
Average SCE Generation Rate ($/kWh)		$0.0575	$0.0690	$0.0707	$0.0730	$0.0747	$0.0763	$0.0780	$0.0797	$0.0814	$0.0830	$0.0847
Total CCE Charges												
SCE Non-bypassable Charges	$0	$1,722,191	$120,365,021	$121,236,384	$122,002,252	$122,943,738	$123,942,523	$43,675,101	$43,787,237	$43,894,603	$44,039,228	$44,191,735
CCE Revenue Requirement	$1,055,416	$11,777,368	$1,078,194,957	$1,117,967,580	$1,166,470,677	$1,207,308,996	$1,246,842,857	$1,290,003,019	$1,332,209,949	$1,376,545,739	$1,419,838,256	$1,464,234,602
Total CCE Generation Revenue Requirement	$1,055,416	$13,499,559	$1,198,559,978	$1,239,203,964	$1,288,472,929	$1,330,252,734	$1,370,785,380	$1,333,678,120	$1,375,997,185	$1,420,440,342	$1,463,877,484	$1,508,426,337
Bundled SCE Revenues	$0	$32,500,966	$2,492,090,079	$2,575,911,573	$2,669,172,535	$2,757,015,564	$2,845,271,634	$2,938,473,662	$3,032,510,433	$3,130,237,483	$3,228,826,383	$3,330,286,114
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$0	$34,292,925	$2,633,663,966	$2,721,104,576	$2,818,663,031	$2,910,272,453	$3,002,223,599	$3,099,421,765	$3,197,407,665	$3,299,272,608	$3,401,941,816	$3,507,590,085
Savings	**$0**	**($1,791,960)**	**($141,573,887)**	**($145,193,003)**	**($149,490,496)**	**($153,256,890)**	**($156,951,965)**	**($160,948,103)**	**($164,897,232)**	**($169,035,125)**	**($173,115,433)**	**($177,303,971)**
Percent Savings		**-5.5%**	**-5.7%**	**-5.6%**	**-5.6%**	**-5.6%**	**-5.5%**	**-5.5%**	**-5.4%**	**-5.4%**	**-5.4%**	**-5.3%**
Cumulative Reserves		$9,227,034	$70,401,961	$150,767,046	$255,027,124	$373,898,187	$507,968,911	$660,340,882	$826,374,594	$1,007,284,943	$1,200,672,685	$1,406,363,040
Reserve Target		$284,346,263										

ICP Community Choice Aggregation
Financial Proforma
Portfolio -100% Renewable

Load Data	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Customer Accounts									
Domestic	959,996	970,844	981,814	992,909	1,004,129	1,015,475	1,026,950	1,038,555	1,050,291
Commercial	99,072	100,192	101,324	102,469	103,627	104,798	105,982	107,180	108,391
Industrial	511	517	523	528	534	540	547	553	0
Lighting & Traffic Control	12,341	12,480	12,621	12,764	12,908	13,054	13,201	13,350	0
Agricultural	3,520	3,560	3,601	3,641	3,682	3,724	3,766	3,809	0
Total Customers	1,075,440	1,087,593	1,099,882	1,112,311	1,124,880	1,137,591	1,150,446	1,163,446	1,158,681
Energy Sales (MWh)									
Domestic	7,701,336	7,788,361	7,876,369	7,965,372	8,055,381	8,146,407	8,238,461	8,331,556	8,425,703
Commercial	4,496,949	4,547,765	4,599,155	4,651,125	4,703,683	4,756,834	4,810,587	4,864,946	4,919,920
Industrial	2,954,376	2,987,760	3,021,522	3,055,665	3,090,194	3,125,114	3,160,427	3,196,140	3,232,257
Lighting & Traffic Control	132,346	133,842	135,354	136,884	138,430	139,995	141,576	143,176	144,794
Agricultural	611,948	618,863	625,857	632,929	640,081	647,314	654,628	662,026	669,507
Total Energy Sales (MWh)	15,896,956	16,076,591	16,258,257	16,441,975	16,627,769	16,815,663	17,005,680	17,197,844	17,392,180
CCE Operating Costs	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Power Supply	$1,243,478,415	$1,277,923,815	$1,313,160,531	$1,349,217,248	$1,386,279,882	$1,425,852,830	$1,466,789,205	$1,508,492,221	$1,551,453,949
Billing & Data Management	$16,128,858	$16,311,114	$16,495,430	$16,681,828	$16,870,333	$17,060,968	$17,253,757	$17,448,724	$17,645,895
SCE Fees	$5,290,374	$5,350,154	$5,410,609	$5,471,748	$5,533,577	$5,596,105	$5,659,340	$5,723,290	$5,787,961
Technical Services	$1,621,263	$1,653,688	$1,686,762	$1,720,497	$1,754,907	$1,790,005	$1,825,805	$1,862,321	$1,899,568
Staffing	$3,145,737	$3,208,652	$3,272,825	$3,338,281	$3,405,047	$3,473,148	$3,542,611	$3,613,463	$3,685,732
General & Administrative expenses	$415,698	$373,012	$380,473	$388,082	$470,844	$428,761	$411,836	$420,072	$428,474
Debt Service (CCE Bonds & Start-up Costs)	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883	$14,643,883
Contribution to Annual Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs	$217,119,621	$229,507,037	$232,181,003	$250,075,388	$261,493,256	$274,691,737	$291,312,684	$307,982,611	$327,100,898
Start-Up Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$6,645,455	$6,819,957	$6,999,274	$7,181,937	$7,370,424	$7,570,752	$7,777,925	$7,989,158	$8,206,661
Total Operating Costs	$1,508,489,304	$1,555,791,312	$1,594,230,788	$1,648,718,892	$1,697,822,152	$1,751,108,188	$1,809,217,045	$1,868,175,743	$1,930,853,020
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$1,508,489,304	$1,555,791,312	$1,594,230,788	$1,648,718,892	$1,697,822,152	$1,751,108,188	$1,809,217,045	$1,868,175,743	$1,930,853,020
Average CCE Rate ($/kWh)	$0.0949	$0.0968	$0.0981	$0.1003	$0.1021	$0.1041	$0.1064	$0.1086	$0.1110
Average SCE Generation Rate ($/kWh)	$0.0863	$0.0880	$0.0891	$0.0912	$0.0928	$0.0947	$0.0967	$0.0988	$0.1009
Total CCE Charges									
SCE Non-bypassable Charges	$44,366,859	$44,527,161	$44,804,342	$44,925,839	$45,126,238	$45,304,664	$45,458,584	$45,627,682	$45,786,716
CCE Revenue Requirement	$1,508,489,304	$1,555,791,312	$1,594,230,788	$1,648,718,892	$1,697,822,152	$1,751,108,188	$1,809,217,045	$1,868,175,743	$1,930,853,020
Total CCE Generation Revenue Requirement	$1,552,856,163	$1,600,318,473	$1,639,035,131	$1,693,644,731	$1,742,948,390	$1,796,412,852	$1,854,675,629	$1,913,803,426	$1,976,639,736
Bundled SCE Revenues	$3,433,543,297	$3,541,557,705	$3,643,564,853	$3,762,275,864	$3,878,272,416	$4,000,321,101	$4,129,074,697	$4,260,994,562	$4,398,764,102
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$3,615,045,547	$3,727,520,440	$3,833,299,267	$3,957,085,239	$4,077,746,123	$4,204,817,418	$4,339,007,558	$4,476,456,403	$4,620,082,911
Savings	**($181,502,250)**	**($185,962,735)**	**($189,734,414)**	**($194,809,375)**	**($199,473,707)**	**($204,496,317)**	**($209,932,861)**	**($215,461,841)**	**($221,318,809)**
Percent Savings	**-5.3%**	**-5.3%**	**-5.2%**	**-5.2%**	**-5.1%**	**-5.1%**	**-5.1%**	**-5.1%**	**-5.0%**
Cumulative Reserves	$1,623,482,661	$1,852,989,698	$2,085,170,701	$2,335,246,090	$2,596,739,346	$2,871,431,083	$3,162,743,767	$3,470,726,377	$3,797,827,275
Reserve Target									

CVAG Community Choice Aggregation
Financial Proforma
Portfolio RPS

Load Data	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts												
Domestic	0	780	94,731	95,801	96,884	97,979	99,086	100,205	101,338	102,483	103,641	104,812
Commercial	0	8,577	12,246	12,385	12,525	12,666	12,809	12,954	13,100	13,248	13,398	13,550
Industrial	0	0	33	33	34	34	35	35	35	36	36	37
Lighting & Traffic Control	0	750	1,152	1,165	1,178	1,191	1,205	1,218	1,232	1,246	1,260	1,274
Agricultural	0	9	432	437	442	447	452	457	462	467	473	478
Total Customers	0	10,116	108,594	109,821	111,062	112,317	113,586	114,870	116,168	117,481	118,808	120,151
Energy Sales (MWh)												
Domestic	0	15	971,817	982,799	993,904	1,005,135	1,016,493	1,027,980	1,039,596	1,051,343	1,063,224	1,075,238
Commercial	0	16,251	464,157	469,402	474,707	480,071	485,496	490,982	496,530	502,141	507,815	513,553
Industrial	0	0	168,487	170,391	172,317	174,264	176,233	178,224	180,238	182,275	184,335	186,418
Lighting & Traffic Control	0	3,451	9,302	9,408	9,514	9,621	9,730	9,840	9,951	10,064	10,177	10,292
Agricultural	0	5,957	109,632	110,870	112,123	113,390	114,672	115,967	117,278	118,603	119,943	121,299
Total Energy Sales (MWh)	0	25,675	1,723,396	1,742,870	1,762,565	1,782,482	1,802,624	1,822,993	1,843,593	1,864,426	1,885,494	1,906,800
CCE Operating Costs	**2017 Jan - June**	**2017 July - Dec**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Power Supply	$0	$1,257,583	$86,127,816	$89,335,669	$93,319,633	$96,590,120	$99,841,575	$103,246,018	$106,729,471	$110,096,494	$113,705,277	$116,946,487
Billing & Data Management	$0	$106,215	$1,628,639	$1,647,043	$1,665,654	$1,684,476	$1,703,511	$1,722,761	$1,742,228	$1,761,915	$1,781,825	$1,801,959
SCE Fees	$39,557	$413,653	$918,803	$540,338	$546,443	$552,616	$558,860	$565,173	$571,559	$578,016	$584,546	$591,151
Technical Services	$620,000	$500,000	$770,000	$867,000	$884,340	$902,027	$920,067	$938,469	$957,238	$976,383	$995,910	$1,015,829
Staffing	$90,000	$310,000	$1,190,000	$1,238,076	$1,262,838	$1,288,094	$1,313,856	$1,340,133	$1,366,936	$1,394,275	$1,422,160	$1,450,603
General & Administrative expenses	$90,000	$150,000	$350,000	$306,000	$312,120	$318,362	$344,730	$356,224	$337,849	$344,606	$351,498	$398,528
Debt Service (CCE Bonds & Start-up Costs)	$0	$585,441	$4,518,055	$4,518,055	$4,518,055	$4,518,055	$3,932,614	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173
Contribution to Annual Reserves	$0	$2,108,273	$6,373,420	$7,223,951	$7,883,898	$0	$0					
New Programs	$0	$0	$0	$0	$0	$8,411,118	$9,501,817	$10,683,769	$11,271,997	$11,812,299	$12,395,778	$12,869,931
Start-Up Capital	$0	($5,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$4,198	$17,768	$551,968	$567,554	$588,689	$606,273	$620,951	$587,041	$605,057	$622,625	$641,414	$658,575
Total Operating Costs	$843,755	$448,934	$102,428,702	$106,243,686	$110,981,670	$114,871,143	$118,737,981	$122,786,762	$126,929,507	$130,933,785	$135,225,581	$139,080,235
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$843,755	$448,934	$102,428,702	$106,243,686	$110,981,670	$114,871,143	$118,737,981	$122,786,762	$126,929,507	$130,933,785	$135,225,581	$139,080,235
Average CCE Rate ($/kWh)		$0.0503	$0.0594	$0.0610	$0.0630	$0.0644	$0.0659	$0.0674	$0.0688	$0.0702	$0.0717	$0.0729
Average SCE Generation Rate ($/kWh)		$0.0599	$0.0708	$0.0726	$0.0750	$0.0767	$0.0784	$0.0802	$0.0820	$0.0836	$0.0854	$0.0868
Total CCE Charges												
SCE Non-bypassable Charges	$0	$230,758	$14,890,359	$15,058,620	$15,228,783	$15,400,868	$15,574,898	$5,892,314	$5,958,897	$6,026,232	$6,094,329	$6,163,195
CCE Revenue Requirement	$843,755	$448,934	$102,428,702	$106,243,686	$110,981,670	$114,871,143	$118,737,981	$122,786,762	$126,929,507	$130,933,785	$135,225,581	$139,080,235
Total CCE Generation Revenue Requirement	$843,755	$679,692	$117,319,061	$121,302,307	$126,210,453	$130,272,010	$134,312,879	$128,679,075	$132,888,404	$136,960,018	$141,319,910	$145,243,430
Bundled SCE Revenues	$0	$3,832,608	$316,552,316	$327,229,345	$339,198,608	$350,357,259	$361,694,778	$373,461,195	$385,558,469	$397,716,797	$410,450,428	$422,904,017
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$0	$3,678,273	$302,612,480	$312,625,791	$323,756,237	$334,238,413	$344,904,494	$355,965,554	$367,340,317	$378,803,261	$390,787,503	$402,575,738
Savings	**$0**	**$154,335**	**$13,939,836**	**$14,603,554**	**$15,442,371**	**$16,118,847**	**$16,790,284**	**$17,495,641**	**$18,218,152**	**$18,913,536**	**$19,662,925**	**$20,328,278**
Percent Savings		**4.0%**	**4.4%**	**4.5%**	**4.6%**	**4.6%**	**4.6%**	**4.7%**	**4.7%**	**4.8%**	**4.8%**	**4.8%**
Cumulative Reserves		$2,108,273	$8,481,693	$15,705,644	$23,589,542	$32,000,660	$41,502,478	$52,186,247	$63,458,244	$75,270,543	$87,666,321	$100,536,251
Reserve Target		$27,736,410										

CVAG Community Choice Aggregation
Financial Proforma
Portfolio RPS

Load Data	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Customer Accounts									
Domestic	105,996	107,194	108,405	109,630	110,869	112,122	113,389	114,670	115,966
Commercial	13,703	13,857	14,014	14,172	14,333	14,495	14,658	14,824	14,991
Industrial	37	37	38	38	39	39	40	40	0
Lighting & Traffic Control	1,289	1,303	1,318	1,333	1,348	1,363	1,379	1,394	0
Agricultural	483	489	494	500	506	511	517	523	0
Total Customers	121,508	122,881	124,270	125,674	127,094	128,530	129,983	131,452	130,958
Energy Sales (MWh)									
Domestic	1,087,388	1,099,676	1,112,102	1,124,669	1,137,378	1,150,230	1,163,227	1,176,372	1,189,665
Commercial	519,356	525,225	531,160	537,162	543,232	549,371	555,578	561,857	568,205
Industrial	188,524	190,654	192,809	194,988	197,191	199,419	201,673	203,952	206,256
Lighting & Traffic Control	10,409	10,526	10,645	10,766	10,887	11,010	11,135	11,261	11,388
Agricultural	122,669	124,055	125,457	126,875	128,309	129,758	131,225	132,708	134,207
Total Energy Sales (MWh)	1,928,347	1,950,137	1,972,173	1,994,459	2,016,996	2,039,788	2,062,838	2,086,148	2,109,722

CCE Operating Costs	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Power Supply	$120,715,713	$124,641,715	$127,608,173	$131,633,023	$135,819,990	$140,182,348	$144,729,275	$149,470,270	$154,412,499
Billing & Data Management	$1,822,321	$1,842,913	$1,863,738	$1,884,799	$1,906,097	$1,927,636	$1,949,418	$1,971,446	$1,993,724
SCE Fees	$597,829	$604,584	$611,414	$618,322	$625,308	$632,373	$639,517	$646,742	$654,049
Technical Services	$1,036,145	$1,056,868	$1,078,006	$1,099,566	$1,121,557	$1,143,988	$1,166,868	$1,190,205	$1,214,009
Staffing	$1,479,615	$1,509,208	$1,539,392	$1,570,180	$1,601,583	$1,633,615	$1,666,287	$1,699,613	$1,733,605
General & Administrative expenses	$415,698	$373,012	$380,473	$388,082	$415,844	$428,761	$411,836	$420,072	$428,474
Debt Service (CCE Bonds & Start-up Costs)	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173
Contribution to Annual Reserves									
New Programs	$13,470,686	$14,158,610	$14,618,002	$15,270,918	$15,932,080	$16,639,080	$17,408,657	$18,187,257	$19,001,297
Start-Up Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$677,658	$697,809	$713,423	$734,340	$756,180	$778,833	$802,271	$826,816	$852,380
Total Operating Costs	$143,562,840	$148,231,892	$151,759,793	$156,546,402	$161,525,811	$166,713,806	$172,121,302	$177,759,596	$183,637,211
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$143,562,840	$148,231,892	$151,759,793	$156,546,402	$161,525,811	$166,713,806	$172,121,302	$177,759,596	$183,637,211
Average CCE Rate ($/kWh)	$0.0744	$0.0760	$0.0770	$0.0785	$0.0801	$0.0817	$0.0834	$0.0852	$0.0870
Average SCE Generation Rate ($/kWh)	$0.0886	$0.0905	$0.0916	$0.0934	$0.0953	$0.0973	$0.0993	$0.1014	$0.1036
Total CCE Charges									
SCE Non-bypassable Charges	$6,117,154	$6,186,278	$6,256,183	$6,326,877	$6,398,371	$6,470,673	$6,543,791	$6,617,736	$6,692,517
CCE Revenue Requirement	$143,562,840	$148,231,892	$151,759,793	$156,546,402	$161,525,811	$166,713,806	$172,121,302	$177,759,596	$183,637,211
Total CCE Generation Revenue Requirement	$149,679,994	$154,418,170	$158,015,976	$162,873,279	$167,924,183	$173,184,479	$178,665,093	$184,377,333	$190,329,728
Bundled SCE Revenues	$436,353,110	$450,279,924	$463,112,047	$477,714,771	$492,827,740	$508,478,593	$524,689,456	$541,483,196	$558,879,668
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$415,124,961	$428,231,555	$440,461,602	$454,223,286	$468,459,290	$483,194,255	$498,448,238	$514,241,961	$530,593,669
Savings	**$21,228,149**	**$22,048,369**	**$22,650,445**	**$23,491,485**	**$24,368,450**	**$25,284,338**	**$26,241,218**	**$27,241,235**	**$28,286,000**
Percent Savings	**4.9%**	**4.9%**	**4.9%**	**4.9%**	**4.9%**	**5.0%**	**5.0%**	**5.0%**	**5.1%**
Cumulative Reserves	$114,006,937	$128,165,547	$142,783,549	$158,054,467	$173,986,546	$190,625,626	$208,034,283	$226,221,540	$245,222,837
Reserve Target									

CVAG Community Choice Aggregation
Financial Proforma
Portfolio -50% Renewable

Load Data	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts												
Domestic	0	780	94,731	95,801	96,884	97,979	99,086	100,205	101,338	102,483	103,641	104,812
Commercial	0	8,577	12,246	12,385	12,525	12,666	12,809	12,954	13,100	13,248	13,398	13,550
Industrial	0	0	33	33	34	34	35	35	35	36	36	37
Lighting & Traffic Control	0	750	1,152	1,165	1,178	1,191	1,205	1,218	1,232	1,246	1,260	1,274
Agricultural	0	9	432	437	442	447	452	457	462	467	473	478
Total Customers	0	10,116	108,594	109,821	111,062	112,317	113,586	114,870	116,168	117,481	118,808	120,151
Energy Sales (MWh)												
Domestic	0	15	971,817	982,799	993,904	1,005,135	1,016,493	1,027,980	1,039,596	1,051,343	1,063,224	1,075,238
Commercial	0	16,251	464,157	469,402	474,707	480,071	485,496	490,982	496,530	502,141	507,815	513,553
Industrial	0	0	168,487	170,391	172,317	174,264	176,233	178,224	180,238	182,275	184,335	186,418
Lighting & Traffic Control	0	3,451	9,302	9,408	9,514	9,621	9,730	9,840	9,951	10,064	10,177	10,292
Agricultural	0	5,957	109,632	110,870	112,123	113,390	114,672	115,967	117,278	118,603	119,943	121,299
Total Energy Sales (MWh)	0	25,675	1,723,396	1,742,870	1,762,565	1,782,482	1,802,624	1,822,993	1,843,593	1,864,426	1,885,494	1,906,800
CCE Operating Costs	**2017 Jan - June**	**2017 July - Dec**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Power Supply	$0	$1,330,076	$89,872,073	$92,484,855	$95,103,582	$97,924,199	$100,729,211	$103,611,908	$106,609,724	$109,653,650	$112,870,312	$116,216,850
Billing & Data Management	$0	$106,215	$1,628,639	$1,647,043	$1,665,654	$1,684,476	$1,703,511	$1,722,761	$1,742,228	$1,761,915	$1,781,825	$1,801,959
SCE Fees	$39,557	$413,653	$918,803	$540,338	$546,443	$552,616	$558,860	$565,173	$571,559	$578,016	$584,546	$591,151
Technical Services	$620,000	$500,000	$770,000	$867,000	$884,340	$902,027	$920,067	$938,469	$957,238	$976,383	$995,910	$1,015,829
Staffing	$90,000	$310,000	$1,190,000	$1,238,076	$1,262,838	$1,288,094	$1,313,856	$1,340,133	$1,366,936	$1,394,275	$1,422,160	$1,450,603
General & Administrative expenses	$90,000	$150,000	$350,000	$306,000	$312,120	$318,362	$344,730	$356,224	$337,849	$344,606	$351,498	$398,528
Debt Service (CCE Bonds & Start-up Costs)	$0	$585,441	$4,518,055	$4,518,055	$4,518,055	$4,518,055	$3,932,614	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173
Contribution to Annual Reserves	$0	$2,127,752	$9,926,777	$11,647,854	$14,018,292	$0	$0					
New Programs	$0	$0	$0	$0	$0	$15,275,450	$17,091,028	$19,086,533	$20,458,736	$21,609,770	$22,893,888	$23,537,518
Start-Up Capital	$0	($5,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$4,198	$18,131	$570,690	$583,300	$597,609	$612,943	$625,389	$588,871	$604,458	$620,411	$637,239	$654,926
Total Operating Costs	$843,755	$541,269	$109,745,038	$113,832,521	$118,908,932	$123,076,224	$127,219,265	$131,557,245	$135,995,901	$140,286,199	$144,884,551	$149,014,537
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$843,755	$541,269	$109,745,038	$113,832,521	$118,908,932	$123,076,224	$127,219,265	$131,557,245	$135,995,901	$140,286,199	$144,884,551	$149,014,537
Average CCE Rate ($/kWh)		$0.0539	$0.0637	$0.0653	$0.0675	$0.0690	$0.0706	$0.0722	$0.0738	$0.0752	$0.0768	$0.0781
Average SCE Generation Rate ($/kWh)		$0.0599	$0.0708	$0.0726	$0.0750	$0.0767	$0.0784	$0.0802	$0.0820	$0.0836	$0.0854	$0.0868
Total CCE Charges												
SCE Non-bypassable Charges	$0	$230,758	$14,890,359	$15,058,620	$15,228,783	$15,400,868	$15,574,898	$5,892,314	$5,958,897	$6,026,232	$6,094,329	$6,163,195
CCE Revenue Requirement	$843,755	$541,269	$109,745,038	$113,832,521	$118,908,932	$123,076,224	$127,219,265	$131,557,245	$135,995,901	$140,286,199	$144,884,551	$149,014,537
Total CCE Generation Revenue Requirement	$843,755	$772,027	$124,635,397	$128,891,141	$134,137,715	$138,477,092	$142,794,163	$137,449,558	$141,954,798	$146,312,431	$150,978,880	$155,177,732
Bundled SCE Revenues	$0	$3,832,608	$316,552,316	$327,229,345	$339,198,608	$350,357,259	$361,694,778	$373,461,195	$385,558,469	$397,716,797	$410,450,428	$422,904,017
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$0	$3,770,608	$309,928,815	$320,214,626	$331,683,499	$342,443,494	$353,385,779	$364,736,037	$376,406,710	$388,155,674	$400,446,473	$412,510,041
Savings	**$0**	**$62,000**	**$6,623,500**	**$7,014,720**	**$7,515,109**	**$7,913,765**	**$8,308,999**	**$8,725,158**	**$9,151,759**	**$9,561,123**	**$10,003,955**	**$10,393,976**
Percent Savings		**1.6%**	**2.1%**	**2.1%**	**2.2%**	**2.3%**	**2.3%**	**2.3%**	**2.4%**	**2.4%**	**2.4%**	**2.5%**
Cumulative Reserves		$2,127,752	$12,054,530	$23,702,384	$37,720,676	$52,996,126	$70,087,154	$89,173,687	$109,632,423	$131,242,193	$154,136,081	$177,673,598
Reserve Target		$28,677,155										

CVAG Community Choice Aggregation
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Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	105,996	107,194	108,405	109,630	110,869	112,122	113,389	114,670	115,966
Commercial	13,703	13,857	14,014	14,172	14,333	14,495	14,658	14,824	14,991
Industrial	37	37	38	38	39	39	40	40	0
Lighting & Traffic Control	1,289	1,303	1,318	1,333	1,348	1,363	1,379	1,394	0
Agricultural	483	489	494	500	506	511	517	523	0
Total Customers	121,508	122,881	124,270	125,674	127,094	128,530	129,983	131,452	130,958
Energy Sales (MWh)									
Domestic	1,087,388	1,099,676	1,112,102	1,124,669	1,137,378	1,150,230	1,163,227	1,176,372	1,189,665
Commercial	519,356	525,225	531,160	537,162	543,232	549,371	555,578	561,857	568,205
Industrial	188,524	190,654	192,809	194,988	197,191	199,419	201,673	203,952	206,256
Lighting & Traffic Control	10,409	10,526	10,645	10,766	10,887	11,010	11,135	11,261	11,388
Agricultural	122,669	124,055	125,457	126,875	128,309	129,758	131,225	132,708	134,207
Total Energy Sales (MWh)	1,928,347	1,950,137	1,972,173	1,994,459	2,016,996	2,039,788	2,062,838	2,086,148	2,109,722

CCE Operating Costs	2028	2029	2030	2031	2032	2033	2034	2035	2036
Power Supply	$119,761,096	$123,386,432	$127,608,173	$131,633,023	$135,819,990	$140,182,348	$144,729,275	$149,470,270	$154,412,499
Billing & Data Management	$1,822,321	$1,842,913	$1,863,738	$1,884,799	$1,906,097	$1,927,636	$1,949,418	$1,971,446	$1,993,724
SCE Fees	$597,829	$604,584	$611,414	$618,322	$625,308	$632,373	$639,517	$646,742	$654,049
Technical Services	$1,036,145	$1,056,868	$1,078,006	$1,099,566	$1,121,557	$1,143,988	$1,166,868	$1,190,205	$1,214,009
Staffing	$1,479,615	$1,509,208	$1,539,392	$1,570,180	$1,601,583	$1,633,615	$1,666,287	$1,699,613	$1,733,605
General & Administrative expenses	$415,698	$373,012	$380,473	$388,082	$415,844	$428,761	$411,836	$420,072	$428,474
Debt Service (CCE Bonds & Start-up Costs)	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173
Contribution to Annual Reserves									
New Programs	$24,684,565	$26,008,162	$25,457,987	$26,452,804	$27,469,638	$28,547,209	$29,703,036	$30,884,371	$32,118,240
Start-Up Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$672,885	$691,532	$713,423	$734,340	$756,180	$778,833	$802,271	$826,816	$852,380
Total Operating Costs	$153,817,329	$158,819,885	$162,599,779	$167,728,288	$173,063,369	$178,621,935	$184,415,680	$190,456,711	$196,754,155
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$153,817,329	$158,819,885	$162,599,779	$167,728,288	$173,063,369	$178,621,935	$184,415,680	$190,456,711	$196,754,155
Average CCE Rate ($/kWh)	$0.0798	$0.0814	$0.0824	$0.0841	$0.0858	$0.0876	$0.0894	$0.0913	$0.0933
Average SCE Generation Rate ($/kWh)	$0.0886	$0.0905	$0.0916	$0.0934	$0.0953	$0.0973	$0.0993	$0.1014	$0.1036
Total CCE Charges									
SCE Non-bypassable Charges	$6,117,154	$6,186,278	$6,256,183	$6,326,877	$6,398,371	$6,470,673	$6,543,791	$6,617,736	$6,692,517
CCE Revenue Requirement	$153,817,329	$158,819,885	$162,599,779	$167,728,288	$173,063,369	$178,621,935	$184,415,680	$190,456,711	$196,754,155
Total CCE Generation Revenue Requirement	$159,934,482	$165,006,162	$168,855,961	$174,055,165	$179,461,741	$185,092,608	$190,959,472	$197,074,447	$203,446,672
Bundled SCE Revenues	$436,353,110	$450,279,924	$463,112,047	$477,714,771	$492,827,740	$508,478,593	$524,689,456	$541,483,196	$558,879,668
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$425,379,450	$438,819,548	$451,301,587	$465,405,172	$479,996,848	$495,102,384	$510,742,617	$526,939,075	$543,710,612
Savings	**$10,973,660**	**$11,460,376**	**$11,810,459**	**$12,309,599**	**$12,830,892**	**$13,376,209**	**$13,946,840**	**$14,544,121**	**$15,169,056**
Percent Savings	**2.5%**	**2.5%**	**2.6%**	**2.6%**	**2.6%**	**2.6%**	**2.7%**	**2.7%**	**2.7%**
Cumulative Reserves	$202,358,163	$228,366,325	$253,824,312	$280,277,116	$307,746,754	$336,293,962	$365,996,998	$396,881,369	$428,999,609
Reserve Target									

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Load Data	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts												
Domestic	0	780	94,731	95,801	96,884	97,979	99,086	100,205	101,338	102,483	103,641	104,812
Commercial	0	8,577	12,246	12,385	12,525	12,666	12,809	12,954	13,100	13,248	13,398	13,550
Industrial	0	0	33	33	34	34	35	35	35	36	36	37
Lighting & Traffic Control	0	750	1,152	1,165	1,178	1,191	1,205	1,218	1,232	1,246	1,260	1,274
Agricultural	0	9	432	437	442	447	452	457	462	467	473	478
Total Customers	0	10,116	108,594	109,821	111,062	112,317	113,586	114,870	116,168	117,481	118,808	120,151
Energy Sales (MWh)												
Domestic	0	15	971,817	982,799	993,904	1,005,135	1,016,493	1,027,980	1,039,596	1,051,343	1,063,224	1,075,238
Commercial	0	16,251	464,157	469,402	474,707	480,071	485,496	490,982	496,530	502,141	507,815	513,553
Industrial	0	0	168,487	170,391	172,317	174,264	176,233	178,224	180,238	182,275	184,335	186,418
Lighting & Traffic Control	0	3,451	9,302	9,408	9,514	9,621	9,730	9,840	9,951	10,064	10,177	10,292
Agricultural	0	5,957	109,632	110,870	112,123	113,390	114,672	115,967	117,278	118,603	119,943	121,299
Total Energy Sales (MWh)	0	25,675	1,723,396	1,742,870	1,762,565	1,782,482	1,802,624	1,822,993	1,843,593	1,864,426	1,885,494	1,906,800
CCE Operating Costs	**2017 Jan - June**	**2017 July - Dec**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Power Supply	$0	$1,774,143	$117,097,797	$120,159,004	$123,200,139	$126,432,728	$129,674,380	$133,037,090	$136,498,693	$140,045,903	$143,804,155	$147,684,617
Billing & Data Management	$0	$106,215	$1,628,639	$1,647,043	$1,665,654	$1,684,476	$1,703,511	$1,722,761	$1,742,228	$1,761,915	$1,781,825	$1,801,959
SCE Fees	$39,557	$413,653	$918,803	$540,338	$546,443	$552,616	$558,860	$565,173	$571,559	$578,016	$584,546	$591,151
Technical Services	$620,000	$500,000	$770,000	$867,000	$884,340	$902,027	$920,067	$938,469	$957,238	$976,383	$995,910	$1,015,829
Staffing	$90,000	$310,000	$1,190,000	$1,238,076	$1,262,838	$1,288,094	$1,313,856	$1,340,133	$1,366,936	$1,394,275	$1,422,160	$1,450,603
General & Administrative expenses	$90,000	$150,000	$350,000	$306,000	$312,120	$318,362	$344,730	$356,224	$337,849	$344,606	$351,498	$398,528
Debt Service (CCE Bonds & Start-up Costs)	$0	$585,441	$4,518,055	$4,518,055	$4,518,055	$4,518,055	$3,932,614	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173
Contribution to Annual Reserves	$0	$2,004,637	$8,172,100	$10,396,256	$13,526,669	$0	$0					
New Programs	$0	$0	$0	$0	$0	$15,342,165	$17,685,628	$20,210,915	$22,152,700	$23,799,002	$25,611,771	$26,682,471
Start-Up Capital	$0	($5,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$4,198	$20,351	$706,818	$721,671	$738,092	$755,486	$770,115	$735,997	$753,903	$772,373	$791,908	$812,265
Total Operating Costs	$843,755	$864,441	$135,352,214	$140,393,443	$146,654,350	$151,794,010	$156,903,761	$162,253,935	$167,728,278	$173,019,645	$178,690,946	$183,784,596
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$843,755	$864,441	$135,352,214	$140,393,443	$146,654,350	$151,794,010	$156,903,761	$162,253,935	$167,728,278	$173,019,645	$178,690,946	$183,784,596
Average CCE Rate ($/kWh)		$0.0665	$0.0785	$0.0806	$0.0832	$0.0852	$0.0870	$0.0890	$0.0910	$0.0928	$0.0948	$0.0964
Average SCE Generation Rate ($/kWh)		$0.0599	$0.0708	$0.0726	$0.0750	$0.0767	$0.0784	$0.0802	$0.0820	$0.0836	$0.0854	$0.0868
Total CCE Charges												
SCE Non-bypassable Charges	$0	$230,758	$14,890,359	$15,058,620	$15,228,783	$15,400,868	$15,574,898	$5,892,314	$5,958,897	$6,026,232	$6,094,329	$6,163,195
CCE Revenue Requirement	$843,755	$864,441	$135,352,214	$140,393,443	$146,654,350	$151,794,010	$156,903,761	$162,253,935	$167,728,278	$173,019,645	$178,690,946	$183,784,596
Total CCE Generation Revenue Requirement	$843,755	$1,095,199	$150,242,573	$155,452,063	$161,883,133	$167,194,878	$172,478,658	$168,146,249	$173,687,175	$179,045,877	$184,785,275	$189,947,791
Bundled SCE Revenues	$0	$3,832,608	$316,552,316	$327,229,345	$339,198,608	$350,357,259	$361,694,778	$373,461,195	$385,558,469	$397,716,797	$410,450,428	$422,904,017
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$0	$4,093,781	$335,535,991	$346,775,547	$359,428,917	$371,161,280	$383,070,274	$395,432,727	$408,139,087	$420,889,121	$434,252,869	$447,280,099
Savings	**$0**	**($261,173)**	**($18,983,675)**	**($19,546,202)**	**($20,230,309)**	**($20,804,021)**	**($21,375,496)**	**($21,971,533)**	**($22,580,618)**	**($23,172,323)**	**($23,802,441)**	**($24,376,083)**
Percent Savings		**-6.8%**	**-6.0%**	**-6.0%**	**-6.0%**	**-5.9%**	**-5.9%**	**-5.9%**	**-5.9%**	**-5.8%**	**-5.8%**	**-5.8%**
Cumulative Reserves		$2,004,637	$10,176,737	$20,572,993	$34,099,662	$49,441,827	$67,127,455	$87,338,371	$109,491,071	$133,290,073	$158,901,844	$185,584,315
Reserve Target		$35,517,618										

CVAG Community Choice Aggregation
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Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	105,996	107,194	108,405	109,630	110,869	112,122	113,389	114,670	115,966
Commercial	13,703	13,857	14,014	14,172	14,333	14,495	14,658	14,824	14,991
Industrial	37	37	38	38	39	39	40	40	0
Lighting & Traffic Control	1,289	1,303	1,318	1,333	1,348	1,363	1,379	1,394	0
Agricultural	483	489	494	500	506	511	517	523	0
Total Customers	121,508	122,881	124,270	125,674	127,094	128,530	129,983	131,452	130,958
Energy Sales (MWh)									
Domestic	1,087,388	1,099,676	1,112,102	1,124,669	1,137,378	1,150,230	1,163,227	1,176,372	1,189,665
Commercial	519,356	525,225	531,160	537,162	543,232	549,371	555,578	561,857	568,205
Industrial	188,524	190,654	192,809	194,988	197,191	199,419	201,673	203,952	206,256
Lighting & Traffic Control	10,409	10,526	10,645	10,766	10,887	11,010	11,135	11,261	11,388
Agricultural	122,669	124,055	125,457	126,875	128,309	129,758	131,225	132,708	134,207
Total Energy Sales (MWh)	1,928,347	1,950,137	1,972,173	1,994,459	2,016,996	2,039,788	2,062,838	2,086,148	2,109,722
CCE Operating Costs	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Power Supply	$151,626,153	$155,830,800	$160,130,352	$164,644,719	$169,237,300	$174,146,086	$179,228,310	$184,428,157	$189,686,298
Billing & Data Management	$1,822,321	$1,842,913	$1,863,738	$1,884,799	$1,906,097	$1,927,636	$1,949,418	$1,971,446	$1,993,724
SCE Fees	$597,829	$604,584	$611,414	$618,322	$625,308	$632,373	$639,517	$646,742	$654,049
Technical Services	$1,036,145	$1,056,868	$1,078,006	$1,099,566	$1,121,557	$1,143,988	$1,166,868	$1,190,205	$1,214,009
Staffing	$1,479,615	$1,509,208	$1,539,392	$1,570,180	$1,601,583	$1,633,615	$1,666,287	$1,699,613	$1,733,605
General & Administrative expenses	$415,698	$373,012	$380,473	$388,082	$415,844	$428,761	$411,836	$420,072	$428,474
Debt Service (CCE Bonds & Start-up Costs)	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173	$3,347,173
Contribution to Annual Reserves									
New Programs	$28,550,893	$30,459,545	$30,713,146	$32,412,649	$34,266,695	$36,092,103	$38,061,831	$40,191,595	$42,577,375
Start-Up Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$832,210	$853,754	$876,034	$899,399	$923,266	$948,652	$974,766	$1,001,606	$1,028,749
Total Operating Costs	$189,708,039	$195,877,858	$200,539,727	$206,864,888	$213,444,822	$220,300,386	$227,446,006	$234,896,610	$242,663,458
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$189,708,039	$195,877,858	$200,539,727	$206,864,888	$213,444,822	$220,300,386	$227,446,006	$234,896,610	$242,663,458
Average CCE Rate ($/kWh)	$0.0984	$0.1004	$0.1017	$0.1037	$0.1058	$0.1080	$0.1103	$0.1126	$0.1150
Average SCE Generation Rate ($/kWh)	$0.0886	$0.0905	$0.0916	$0.0934	$0.0953	$0.0973	$0.0993	$0.1014	$0.1036
Total CCE Charges									
SCE Non-bypassable Charges	$6,117,154	$6,186,278	$6,256,183	$6,326,877	$6,398,371	$6,470,673	$6,543,791	$6,617,736	$6,692,517
CCE Revenue Requirement	$189,708,039	$195,877,858	$200,539,727	$206,864,888	$213,444,822	$220,300,386	$227,446,006	$234,896,610	$242,663,458
Total CCE Generation Revenue Requirement	$195,825,192	$202,064,136	$206,795,910	$213,191,765	$219,843,193	$226,771,059	$233,989,797	$241,514,346	$249,355,974
Bundled SCE Revenues	$436,353,110	$450,279,924	$463,112,047	$477,714,771	$492,827,740	$508,478,593	$524,689,456	$541,483,196	$558,879,668
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$461,270,160	$475,877,521	$489,241,535	$504,541,772	$520,378,300	$536,780,836	$553,772,942	$571,378,974	$589,619,915
Savings	**($24,917,050)**	**($25,597,597)**	**($26,129,489)**	**($26,827,002)**	**($27,550,561)**	**($28,302,243)**	**($29,083,486)**	**($29,895,779)**	**($30,740,247)**
Percent Savings	**-5.7%**	**-5.7%**	**-5.6%**	**-5.6%**	**-5.6%**	**-5.6%**	**-5.5%**	**-5.5%**	**-5.5%**
Cumulative Reserves	$214,135,207	$244,594,752	$275,307,898	$307,720,547	$341,987,242	$378,079,345	$416,141,176	$456,332,771	$498,910,146
Reserve Target									

WRCOG Community Choice Aggregation
Financial Proforma
Portfolio RPS

Load Data	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts												
Domestic	0	1,919	302,231	305,647	309,100	312,593	316,125	319,698	323,310	326,964	330,658	334,395
Commercial	0	14,460	27,489	27,799	28,113	28,431	28,752	29,077	29,406	29,738	30,074	30,414
Industrial	0	0	144	146	148	149	151	153	154	156	158	160
Lighting & Traffic Control	0	1,955	3,925	3,969	4,014	4,059	4,105	4,152	4,199	4,246	4,294	4,342
Agricultural	0	11	1,039	1,051	1,063	1,075	1,087	1,099	1,112	1,124	1,137	1,150
Total Customers	0	18,346	334,828	338,612	342,438	346,308	350,221	354,179	358,181	362,228	366,321	370,461
Energy Sales (MWh)												
Domestic	0	31	2,516,796	2,545,236	2,573,997	2,603,084	2,632,498	2,662,246	2,692,329	2,722,752	2,753,519	2,784,634
Commercial	0	40,038	1,192,869	1,206,348	1,219,980	1,233,766	1,247,707	1,261,806	1,276,065	1,290,484	1,305,067	1,319,814
Industrial	0	0	654,313	661,706	669,184	676,745	684,393	692,126	699,947	707,857	715,856	723,945
Lighting & Traffic Control	0	13,960	43,153	43,641	44,134	44,633	45,137	45,647	46,163	46,685	47,212	47,746
Agricultural	0	4,688	171,918	173,861	175,826	177,812	179,822	181,854	183,909	185,987	188,089	190,214
Total Energy Sales (MWh)	0	58,716	4,579,049	4,630,793	4,683,121	4,736,040	4,789,557	4,843,679	4,898,413	4,953,765	5,009,742	5,066,352
CCE Operating Costs	**2017 Jan - June**	**2017 July - Dec**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Power Supply	$0	$2,901,513	$229,794,786	$238,113,503	$248,573,442	$257,145,606	$265,823,405	$274,823,091	$284,041,261	$293,064,953	$302,673,287	$311,345,193
Billing & Data Management	$0	$192,634	$5,021,569	$5,078,313	$5,135,698	$5,193,731	$5,252,420	$5,311,773	$5,371,796	$5,432,497	$5,493,884	$5,555,965
SCE Fees	$68,749	$1,228,726	$2,873,783	$1,665,795	$1,684,617	$1,703,652	$1,722,902	$1,742,369	$1,762,057	$1,781,967	$1,802,102	$1,822,465
Technical Services	$620,000	$740,000	$1,310,000	$1,356,600	$1,383,732	$1,411,407	$1,439,635	$1,468,427	$1,497,796	$1,527,752	$1,558,307	$1,589,473
Staffing	$90,000	$310,000	$1,704,167	$2,080,800	$2,122,416	$2,164,864	$2,208,162	$2,252,325	$2,297,371	$2,343,319	$2,390,185	$2,437,989
General & Administrative expenses	$90,000	$150,000	$420,000	$306,000	$312,120	$318,362	$344,730	$391,224	$337,849	$344,606	$351,498	$398,528
Debt Service (CCE Bonds & Start-up Costs)	$0	$819,618	$6,659,995	$6,659,995	$6,659,995	$6,659,995	$5,840,377	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760
Contribution to Annual Reserves	$0	$1,571,688	$20,274,491	$22,514,010	$24,114,652	$25,396,216	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$0	$27,496,681	$29,759,516	$31,203,800	$32,552,615	$33,996,921	$35,241,305
Start-Up Capital	$0	($6,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$4,344	$34,169	$1,434,123	$1,473,712	$1,528,998	$1,574,882	$1,617,333	$1,530,583	$1,578,031	$1,624,829	$1,674,573	$1,719,858
Total Operating Costs	$873,093	$1,948,349	$269,492,913	$279,248,727	$291,515,669	$301,568,716	$311,745,645	$322,300,068	$333,110,720	$343,693,297	$354,961,517	$365,131,535
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$873,093	$1,948,349	$269,492,913	$279,248,727	$291,515,669	$301,568,716	$311,745,645	$322,300,068	$333,110,720	$343,693,297	$354,961,517	$365,131,535
Average CCE Rate ($/kWh)		$0.0481	$0.0589	$0.0603	$0.0622	$0.0637	$0.0651	$0.0665	$0.0680	$0.0694	$0.0709	$0.0721
Average SCE Generation Rate ($/kWh)		$0.0572	$0.0701	$0.0718	$0.0741	$0.0758	$0.0775	$0.0792	$0.0810	$0.0826	$0.0844	$0.0858
Total CCE Charges												
SCE Non-bypassable Charges	$0	$491,389	$39,040,255	$39,481,410	$39,927,550	$40,378,731	$40,835,011	$15,106,646	$15,277,351	$15,449,985	$15,624,570	$15,801,128
CCE Revenue Requirement	$873,093	$1,948,349	$269,492,913	$279,248,727	$291,515,669	$301,568,716	$311,745,645	$322,300,068	$333,110,720	$343,693,297	$354,961,517	$365,131,535
Total CCE Generation Revenue Requirement	$873,093	$2,439,738	$308,533,168	$318,730,136	$331,443,219	$341,947,447	$352,580,655	$337,406,714	$348,388,072	$359,143,282	$370,586,087	$380,932,663
Bundled SCE Revenues	$0	$9,149,294	$833,422,747	$861,196,970	$892,470,098	$921,633,162	$951,485,800	$982,347,021	$1,014,090,088	$1,046,156,636	$1,079,653,180	$1,112,475,447
Total CCE Customer Bill Revenues (Power Supply and Delivery	$0	$8,785,861	$796,372,072	$822,449,424	$851,549,194	$878,962,439	$907,043,525	$936,063,177	$965,917,778	$996,141,231	$1,027,666,032	$1,058,727,711
Savings	**$0**	**$363,434**	**$37,050,674**	**$38,747,546**	**$40,920,904**	**$42,670,723**	**$44,442,274**	**$46,283,843**	**$48,172,310**	**$50,015,405**	**$51,987,148**	**$53,747,736**
Percent Savings		**4.0%**	**4.4%**	**4.5%**	**4.6%**	**4.6%**	**4.7%**	**4.7%**	**4.8%**	**4.8%**	**4.8%**	**4.8%**
Cumulative Reserves		$1,571,688	$21,846,179	$44,360,189	$68,474,841	$93,871,057	$121,367,738	$151,127,254	$182,331,054	$214,883,669	$248,880,590	$284,121,895
Reserve Target		$77,133,292										

WRCOG Community Choice Aggregation
Financial Proforma
Portfolio RPS

Load Data	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Customer Accounts									
Domestic	338,173	341,995	345,859	349,768	353,720	357,717	361,759	365,847	369,981
Commercial	30,758	31,105	31,457	31,812	32,172	32,535	32,903	33,275	33,651
Industrial	162	163	165	167	169	171	173	175	0
Lighting & Traffic Control	4,392	4,441	4,491	4,542	4,593	4,645	4,698	4,751	0
Agricultural	1,163	1,176	1,189	1,203	1,216	1,230	1,244	1,258	0
Total Customers	374,647	378,881	383,162	387,492	391,870	396,298	400,777	405,305	403,632
Energy Sales (MWh)									
Domestic	2,816,101	2,847,922	2,880,104	2,912,649	2,945,562	2,978,847	3,012,508	3,046,549	3,080,975
Commercial	1,334,728	1,349,810	1,365,063	1,380,488	1,396,088	1,411,864	1,427,818	1,443,952	1,460,269
Industrial	732,125	740,398	748,765	757,226	765,782	774,436	783,187	792,037	800,987
Lighting & Traffic Control	48,285	48,831	49,383	49,941	50,505	51,076	51,653	52,237	52,827
Agricultural	192,363	194,537	196,735	198,958	201,207	203,480	205,780	208,105	210,456
Total Energy Sales (MWh)	5,123,602	5,181,499	5,240,050	5,299,262	5,359,144	5,419,702	5,480,945	5,542,880	5,605,514

CCE Operating Costs	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Power Supply	$321,288,943	$331,789,420	$339,780,613	$350,560,224	$361,621,599	$373,280,365	$385,469,911	$398,069,919	$411,358,419
Billing & Data Management	$5,618,748	$5,682,239	$5,746,449	$5,811,384	$5,877,052	$5,943,463	$6,010,624	$6,078,544	$6,147,232
SCE Fees	$1,843,057	$1,863,883	$1,884,943	$1,906,242	$1,927,781	$1,949,564	$1,971,593	$1,993,870	$2,016,400
Technical Services	$1,621,263	$1,653,688	$1,686,762	$1,720,497	$1,754,907	$1,790,005	$1,825,805	$1,862,321	$1,899,568
Staffing	$2,486,749	$2,536,484	$2,587,213	$2,638,958	$2,691,737	$2,745,571	$2,800,483	$2,856,492	$2,913,622
General & Administrative expenses	$485,698	$373,012	$380,473	$388,082	$415,844	$463,761	$411,836	$420,072	$428,474
Debt Service (CCE Bonds & Start-up Costs)	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760
Contribution to Annual Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs	$36,657,501	$38,364,057	$39,526,302	$41,153,506	$42,805,016	$44,533,731	$46,449,029	$48,369,874	$50,403,157
Start-Up Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$1,770,397	$1,824,056	$1,865,793	$1,921,495	$1,978,731	$2,039,079	$2,101,606	$2,166,510	$2,234,883
Total Operating Costs	$376,793,115	$389,107,598	$398,479,307	$411,121,147	$424,093,426	$437,766,298	$452,061,646	$466,838,364	$482,422,514
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$376,793,115	$389,107,598	$398,479,307	$411,121,147	$424,093,426	$437,766,298	$452,061,646	$466,838,364	$482,422,514
Average CCE Rate ($/kWh)	$0.0735	$0.0751	$0.0760	$0.0776	$0.0791	$0.0808	$0.0825	$0.0842	$0.0861
Average SCE Generation Rate ($/kWh)	$0.0875	$0.0894	$0.0905	$0.0924	$0.0942	$0.0962	$0.0982	$0.1003	$0.1025
Total CCE Charges									
SCE Non-bypassable Charges	$15,714,145	$15,891,714	$16,071,291	$16,252,896	$16,436,554	$16,622,287	$16,810,119	$17,000,073	$17,192,174
CCE Revenue Requirement	$376,793,115	$389,107,598	$398,479,307	$411,121,147	$424,093,426	$437,766,298	$452,061,646	$466,838,364	$482,422,514
Total CCE Generation Revenue Requirement	$392,507,260	$404,999,313	$414,550,597	$427,374,043	$440,529,980	$454,388,586	$468,871,765	$483,838,437	$499,614,689
Bundled SCE Revenues	$1,147,726,447	$1,184,428,365	$1,218,321,871	$1,256,825,188	$1,296,461,281	$1,337,694,117	$1,380,454,747	$1,424,599,990	$1,470,543,601
Total CCE Customer Bill Revenues (Power Supply and Delivery	$1,091,670,474	$1,126,204,347	$1,158,492,341	$1,194,769,294	$1,232,118,134	$1,270,932,348	$1,311,157,886	$1,352,678,470	$1,395,845,773
Savings	**$56,055,972**	**$58,224,018**	**$59,829,529**	**$62,055,893**	**$64,343,146**	**$66,761,770**	**$69,296,861**	**$71,921,520**	**$74,697,828**
Percent Savings	**4.9%**	**4.9%**	**4.9%**	**4.9%**	**5.0%**	**5.0%**	**5.0%**	**5.0%**	**5.1%**
Cumulative Reserves	$320,779,395	$359,143,452	$398,669,754	$439,823,260	$482,628,276	$527,162,007	$573,611,036	$621,980,910	$672,384,067
Reserve Target									

WRCOG Community Choice Aggregation
Financial Proforma
Portfolio -50% Renewable

Load Data	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts												
Domestic	0	1,919	302,231	305,647	309,100	312,593	316,125	319,698	323,310	326,964	330,658	334,395
Commercial	0	14,460	27,489	27,799	28,113	28,431	28,752	29,077	29,406	29,738	30,074	30,414
Industrial	0	0	144	146	148	149	151	153	154	156	158	160
Lighting & Traffic Control	0	1,955	3,925	3,969	4,014	4,059	4,105	4,152	4,199	4,246	4,294	4,342
Agricultural	0	11	1,039	1,051	1,063	1,075	1,087	1,099	1,112	1,124	1,137	1,150
Total Customers	0	18,346	334,828	338,612	342,438	346,308	350,221	354,179	358,181	362,228	366,321	370,461
Energy Sales (MWh)												
Domestic	0	31	2,516,796	2,545,236	2,573,997	2,603,084	2,632,498	2,662,246	2,692,329	2,722,752	2,753,519	2,784,634
Commercial	0	40,038	1,192,869	1,206,348	1,219,980	1,233,766	1,247,707	1,261,806	1,276,065	1,290,484	1,305,067	1,319,814
Industrial	0	0	654,313	661,706	669,184	676,745	684,393	692,126	699,947	707,857	715,856	723,945
Lighting & Traffic Control	0	13,960	43,153	43,641	44,134	44,633	45,137	45,647	46,163	46,685	47,212	47,746
Agricultural	0	4,688	171,918	173,861	175,826	177,812	179,822	181,854	183,909	185,987	188,089	190,214
Total Energy Sales (MWh)	0	58,716	4,579,049	4,630,793	4,683,121	4,736,040	4,789,557	4,843,679	4,898,413	4,953,765	5,009,742	5,066,352
	2017	**2017**										
CCE Operating Costs	**Jan - June**	**July - Dec**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Power Supply	$0	$3,042,266	$239,817,771	$246,529,453	$253,410,401	$260,765,453	$268,145,822	$275,831,414	$283,833,176	$291,963,329	$300,514,540	$309,463,593
Billing & Data Management	$0	$192,634	$5,021,569	$5,078,313	$5,135,698	$5,193,731	$5,252,420	$5,311,773	$5,371,796	$5,432,497	$5,493,884	$5,555,965
SCE Fees	$68,749	$1,228,726	$2,873,783	$1,665,795	$1,684,617	$1,703,652	$1,722,902	$1,742,369	$1,762,057	$1,781,967	$1,802,102	$1,822,465
Technical Services	$620,000	$740,000	$1,310,000	$1,356,600	$1,383,732	$1,411,407	$1,439,635	$1,468,427	$1,497,796	$1,527,752	$1,558,307	$1,589,473
Staffing	$90,000	$310,000	$1,704,167	$2,080,800	$2,122,416	$2,164,864	$2,208,162	$2,252,325	$2,297,371	$2,343,319	$2,390,185	$2,437,989
General & Administrative expenses	$90,000	$150,000	$420,000	$306,000	$312,120	$318,362	$344,730	$391,224	$337,849	$344,606	$351,498	$398,528
Debt Service (CCE Bonds & Start-up Costs)	$0	$819,618	$6,659,995	$6,659,995	$6,659,995	$6,659,995	$5,840,377	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760
Contribution to Annual Reserves	$0	$1,557,868	$22,392,737	$26,688,660	$32,441,122	$35,400,664	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$0	$39,265,431	$43,326,392	$46,482,220	$49,207,777	$52,224,244	$53,650,169
Start-Up Capital	$0	($6,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$4,344	$34,873	$1,484,238	$1,515,792	$1,553,183	$1,592,981	$1,628,945	$1,535,625	$1,576,991	$1,619,321	$1,663,779	$1,710,449
Total Operating Costs	$873,093	$2,075,985	$281,684,259	$291,881,407	$304,703,283	$315,211,110	$325,848,424	$336,880,310	$348,180,015	$359,241,327	$371,019,300	$381,649,391
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$873,093	$2,075,985	$281,684,259	$291,881,407	$304,703,283	$315,211,110	$325,848,424	$336,880,310	$348,180,015	$359,241,327	$371,019,300	$381,649,391
Average CCE Rate ($/kWh)		$0.0502	$0.0615	$0.0630	$0.0651	$0.0666	$0.0680	$0.0696	$0.0711	$0.0725	$0.0741	$0.0753
Average SCE Generation Rate ($/kWh)		$0.0572	$0.0701	$0.0718	$0.0741	$0.0758	$0.0775	$0.0792	$0.0810	$0.0826	$0.0844	$0.0858
Total CCE Charges												
SCE Non-bypassable Charges	$0	$491,389	$39,040,255	$39,481,410	$39,927,550	$40,378,731	$40,835,011	$15,106,646	$15,277,351	$15,449,985	$15,624,570	$15,801,128
CCE Revenue Requirement	$873,093	$2,075,985	$281,684,259	$291,881,407	$304,703,283	$315,211,110	$325,848,424	$336,880,310	$348,180,015	$359,241,327	$371,019,300	$381,649,391
Total CCE Generation Revenue Requirement	$873,093	$2,567,375	$320,724,514	$331,362,817	$344,630,833	$355,589,841	$366,683,434	$351,986,955	$363,457,366	$374,691,313	$386,643,870	$397,450,518
Bundled SCE Revenues	$0	$9,149,294	$833,422,747	$861,196,970	$892,470,098	$921,633,162	$951,485,800	$982,347,021	$1,014,090,088	$1,046,156,636	$1,079,653,180	$1,112,475,447
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$0	$8,913,497	$808,563,418	$835,082,105	$864,736,808	$892,604,833	$921,146,305	$950,643,418	$980,987,073	$1,011,689,261	$1,043,723,815	$1,075,245,566
Savings	**$0**	**$235,797**	**$24,859,328**	**$26,114,865**	**$27,733,290**	**$29,028,329**	**$30,339,495**	**$31,703,602**	**$33,103,015**	**$34,467,375**	**$35,929,365**	**$37,229,881**
Percent Savings		**2.6%**	**3.0%**	**3.0%**	**3.1%**	**3.1%**	**3.2%**	**3.2%**	**3.3%**	**3.3%**	**3.3%**	**3.3%**
Cumulative Reserves		$1,557,868	$23,950,605	$50,639,265	$83,080,387	$118,481,051	$157,746,482	$201,072,873	$247,555,093	$296,762,870	$348,987,114	$402,637,284
Reserve Target		$80,181,128										

WRCOG Community Choice Aggregation
Financial Proforma
Portfolio -50% Renewable

Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	338,173	341,995	345,859	349,768	353,720	357,717	361,759	365,847	369,981
Commercial	30,758	31,105	31,457	31,812	32,172	32,535	32,903	33,275	33,651
Industrial	162	163	165	167	169	171	173	175	0
Lighting & Traffic Control	4,392	4,441	4,491	4,542	4,593	4,645	4,698	4,751	0
Agricultural	1,163	1,176	1,189	1,203	1,216	1,230	1,244	1,258	0
Total Customers	374,647	378,881	383,162	387,492	391,870	396,298	400,777	405,305	403,632
Energy Sales (MWh)									
Domestic	2,816,101	2,847,922	2,880,104	2,912,649	2,945,562	2,978,847	3,012,508	3,046,549	3,080,975
Commercial	1,334,728	1,349,810	1,365,063	1,380,488	1,396,088	1,411,864	1,427,818	1,443,952	1,460,269
Industrial	732,125	740,398	748,765	757,226	765,782	774,436	783,187	792,037	800,987
Lighting & Traffic Control	48,285	48,831	49,383	49,941	50,505	51,076	51,653	52,237	52,827
Agricultural	192,363	194,537	196,735	198,958	201,207	203,480	205,780	208,105	210,456
Total Energy Sales (MWh)	5,123,602	5,181,499	5,240,050	5,299,262	5,359,144	5,419,702	5,480,945	5,542,880	5,605,514
CCE Operating Costs	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Power Supply	$318,781,912	$328,536,021	$339,780,613	$350,560,224	$361,621,599	$373,280,365	$385,469,911	$398,069,919	$411,358,419
Billing & Data Management	$5,618,748	$5,682,239	$5,746,449	$5,811,384	$5,877,052	$5,943,463	$6,010,624	$6,078,544	$6,147,232
SCE Fees	$1,843,057	$1,863,883	$1,884,943	$1,906,242	$1,927,781	$1,949,564	$1,971,593	$1,993,870	$2,016,400
Technical Services	$1,621,263	$1,653,688	$1,686,762	$1,720,497	$1,754,907	$1,790,005	$1,825,805	$1,862,321	$1,899,568
Staffing	$2,486,749	$2,536,484	$2,587,213	$2,638,958	$2,691,737	$2,745,571	$2,800,483	$2,856,492	$2,913,622
General & Administrative expenses	$485,698	$373,012	$380,473	$388,082	$415,844	$463,761	$411,836	$420,072	$428,474
Debt Service (CCE Bonds & Start-up Costs)	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760
Contribution to Annual Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs	$56,222,470	$59,236,209	$57,552,747	$59,751,843	$61,990,194	$64,337,445	$66,899,437	$69,488,753	$72,227,033
Start-Up Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$1,757,862	$1,807,789	$1,865,793	$1,921,495	$1,978,731	$2,039,079	$2,101,606	$2,166,510	$2,234,883
Total Operating Costs	$393,838,518	$406,710,085	$416,505,751	$429,719,484	$443,278,605	$457,570,012	$472,512,054	$487,957,242	$504,246,390
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$393,838,518	$406,710,085	$416,505,751	$429,719,484	$443,278,605	$457,570,012	$472,512,054	$487,957,242	$504,246,390
Average CCE Rate ($/kWh)	$0.0769	$0.0785	$0.0795	$0.0811	$0.0827	$0.0844	$0.0862	$0.0880	$0.0900
Average SCE Generation Rate ($/kWh)	$0.0875	$0.0894	$0.0905	$0.0924	$0.0942	$0.0962	$0.0982	$0.1003	$0.1025
Total CCE Charges									
SCE Non-bypassable Charges	$15,714,145	$15,891,714	$16,071,291	$16,252,896	$16,436,554	$16,622,287	$16,810,119	$17,000,073	$17,192,174
CCE Revenue Requirement	$393,838,518	$406,710,085	$416,505,751	$429,719,484	$443,278,605	$457,570,012	$472,512,054	$487,957,242	$504,246,390
Total CCE Generation Revenue Requirement	$409,552,662	$422,601,799	$432,577,042	$445,972,381	$459,715,159	$474,192,299	$489,322,173	$504,957,316	$521,438,564
Bundled SCE Revenues	$1,147,726,447	$1,184,428,365	$1,218,321,871	$1,256,825,188	$1,296,461,281	$1,337,694,117	$1,380,454,747	$1,424,599,990	$1,470,543,601
Total CCE Customer Bill Revenues (Power Supply and Delivery	$1,108,715,877	$1,143,806,833	$1,176,518,786	$1,213,367,632	$1,251,303,313	$1,290,736,061	$1,331,608,293	$1,373,797,349	$1,417,669,648
Savings	**$39,010,570**	**$40,621,532**	**$41,803,085**	**$43,457,556**	**$45,157,967**	**$46,958,056**	**$48,846,453**	**$50,802,641**	**$52,873,953**
Percent Savings	**3.4%**	**3.4%**	**3.4%**	**3.5%**	**3.5%**	**3.5%**	**3.5%**	**3.6%**	**3.6%**
Cumulative Reserves	$458,859,754	$518,095,962	$575,648,710	$635,400,553	$697,390,747	$761,728,192	$828,627,629	$898,116,381	$970,343,414
Reserve Target									

WRCOG Community Choice Aggregation
Financial Proforma
Portfolio -100% Renewable

	2017	2017										
Load Data	**Jan - June**	**July - Dec**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Customer Accounts												
Domestic	0	1,919	302,231	305,647	309,100	312,593	316,125	319,698	323,310	326,964	330,658	334,395
Commercial	0	14,460	27,489	27,799	28,113	28,431	28,752	29,077	29,406	29,738	30,074	30,414
Industrial	0	0	144	146	148	149	151	153	154	156	158	160
Lighting & Traffic Control	0	1,955	3,925	3,969	4,014	4,059	4,105	4,152	4,199	4,246	4,294	4,342
Agricultural	0	11	1,039	1,051	1,063	1,075	1,087	1,099	1,112	1,124	1,137	1,150
Total Customers	0	18,346	334,828	338,612	342,438	346,308	350,221	354,179	358,181	362,228	366,321	370,461
Energy Sales (MWh)												
Domestic	0	31	2,516,796	2,545,236	2,573,997	2,603,084	2,632,498	2,662,246	2,692,329	2,722,752	2,753,519	2,784,634
Commercial	0	40,038	1,192,869	1,206,348	1,219,980	1,233,766	1,247,707	1,261,806	1,276,065	1,290,484	1,305,067	1,319,814
Industrial	0	0	654,313	661,706	669,184	676,745	684,393	692,126	699,947	707,857	715,856	723,945
Lighting & Traffic Control	0	13,960	43,153	43,641	44,134	44,633	45,137	45,647	46,163	46,685	47,212	47,746
Agricultural	0	4,688	171,918	173,861	175,826	177,812	179,822	181,854	183,909	185,987	188,089	190,214
Total Energy Sales (MWh)	0	58,716	4,579,049	4,630,793	4,683,121	4,736,040	4,789,557	4,843,679	4,898,413	4,953,765	5,009,742	5,066,352
	2017	**2017**										
CCE Operating Costs	**Jan - June**	**July - Dec**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Power Supply	$0	$4,037,959	$313,511,321	$320,806,679	$328,299,543	$336,307,961	$344,453,480	$352,877,874	$361,535,487	$370,482,012	$379,738,967	$389,410,496
Billing & Data Management	$0	$192,634	$5,021,569	$5,078,313	$5,135,698	$5,193,731	$5,252,420	$5,311,773	$5,371,796	$5,432,497	$5,493,884	$5,555,965
SCE Fees	$68,749	$1,228,726	$2,873,783	$1,665,795	$1,684,617	$1,703,652	$1,722,902	$1,742,369	$1,762,057	$1,781,967	$1,802,102	$1,822,465
Technical Services	$620,000	$740,000	$1,310,000	$1,356,600	$1,383,732	$1,411,407	$1,439,635	$1,468,427	$1,497,796	$1,527,752	$1,558,307	$1,589,473
Staffing	$90,000	$310,000	$1,704,167	$2,080,800	$2,122,416	$2,164,864	$2,208,162	$2,252,325	$2,297,371	$2,343,319	$2,390,185	$2,437,989
General & Administrative expenses	$90,000	$150,000	$420,000	$306,000	$312,120	$318,362	$344,730	$391,224	$337,849	$344,606	$351,498	$398,528
Debt Service (CCE Bonds & Start-up Costs)	$0	$819,618	$6,659,995	$6,659,995	$6,659,995	$6,659,995	$5,840,377	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760
Contribution to Annual Reserves	$0	$1,185,303	$8,324,975	$14,206,134	$22,074,475	$26,615,384	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$0	$31,976,753	$37,644,834	$42,548,188	$46,809,175	$51,624,890	$54,588,766
Start-Up Capital	$0	($6,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$4,344	$39,852	$1,852,705	$1,887,178	$1,927,628	$1,970,694	$2,010,484	$1,920,857	$1,965,502	$2,011,914	$2,059,901	$2,110,184
Total Operating Costs	$873,093	$2,704,092	$341,678,515	$354,047,493	$369,600,223	$382,346,050	$395,248,942	$408,630,444	$422,336,806	$435,754,002	$450,040,494	$462,934,625
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$873,093	$2,704,092	$341,678,515	$354,047,493	$369,600,223	$382,346,050	$395,248,942	$408,630,444	$422,336,806	$435,754,002	$450,040,494	$462,934,625
Average CCE Rate ($/kWh)		$0.0609	$0.0746	$0.0765	$0.0789	$0.0807	$0.0825	$0.0844	$0.0862	$0.0880	$0.0898	$0.0914
Average SCE Generation Rate ($/kWh)		$0.0572	$0.0701	$0.0718	$0.0741	$0.0758	$0.0775	$0.0792	$0.0810	$0.0826	$0.0844	$0.0858
Total CCE Charges												
SCE Non-bypassable Charges	$0	$491,389	$39,040,255	$39,481,410	$39,927,550	$40,378,731	$40,835,011	$15,106,646	$15,277,351	$15,449,985	$15,624,570	$15,801,128
CCE Revenue Requirement	$873,093	$2,704,092	$341,678,515	$354,047,493	$369,600,223	$382,346,050	$395,248,942	$408,630,444	$422,336,806	$435,754,002	$450,040,494	$462,934,625
Total CCE Generation Revenue Requirement	$873,093	$3,195,481	$380,718,770	$393,528,903	$409,527,773	$422,724,781	$436,083,953	$423,737,090	$437,614,157	$451,203,987	$465,665,064	$478,735,753
Bundled SCE Revenues	$0	$9,149,294	$833,422,747	$861,196,970	$892,470,098	$921,633,162	$951,485,800	$982,347,021	$1,014,090,088	$1,046,156,636	$1,079,653,180	$1,112,475,447
Total CCE Customer Bill Revenues (Power Supply and Delivery	$0	$9,541,604	$868,557,674	$897,248,191	$929,633,749	$959,739,774	$990,546,823	$1,022,393,553	$1,055,143,864	$1,088,201,935	$1,122,745,010	$1,156,530,801
Savings	**$0**	**($392,310)**	**($35,134,927)**	**($36,051,220)**	**($37,163,650)**	**($38,106,611)**	**($39,061,023)**	**($40,046,532)**	**($41,053,776)**	**($42,045,300)**	**($43,091,830)**	**($44,055,354)**
Percent Savings		**-4.3%**	**-4.2%**	**-4.2%**	**-4.2%**	**-4.1%**	**-4.1%**	**-4.1%**	**-4.0%**	**-4.0%**	**-4.0%**	**-4.0%**
Cumulative Reserves		$1,185,303	$9,510,278	$23,716,412	$45,790,886	$72,406,270	$104,383,023	$142,027,857	$184,576,046	$231,385,221	$283,010,110	$337,598,876
Reserve Target		$95,179,692										

WRCOG Community Choice Aggregation
Financial Proforma
Portfolio -100% Renewable

Load Data	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Customer Accounts									
Domestic	338,173	341,995	345,859	349,768	353,720	357,717	361,759	365,847	369,981
Commercial	30,758	31,105	31,457	31,812	32,172	32,535	32,903	33,275	33,651
Industrial	162	163	165	167	169	171	173	175	0
Lighting & Traffic Control	4,392	4,441	4,491	4,542	4,593	4,645	4,698	4,751	0
Agricultural	1,163	1,176	1,189	1,203	1,216	1,230	1,244	1,258	0
Total Customers	374,647	378,881	383,162	387,492	391,870	396,298	400,777	405,305	403,632
Energy Sales (MWh)									
Domestic	2,816,101	2,847,922	2,880,104	2,912,649	2,945,562	2,978,847	3,012,508	3,046,549	3,080,975
Commercial	1,334,728	1,349,810	1,365,063	1,380,488	1,396,088	1,411,864	1,427,818	1,443,952	1,460,269
Industrial	732,125	740,398	748,765	757,226	765,782	774,436	783,187	792,037	800,987
Lighting & Traffic Control	48,285	48,831	49,383	49,941	50,505	51,076	51,653	52,237	52,827
Agricultural	192,363	194,537	196,735	198,958	201,207	203,480	205,780	208,105	210,456
Total Energy Sales (MWh)	5,123,602	5,181,499	5,240,050	5,299,262	5,359,144	5,419,702	5,480,945	5,542,880	5,605,514
CCE Operating Costs	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Power Supply	$399,260,495	$409,838,077	$420,638,303	$431,859,515	$443,204,440	$455,241,222	$467,405,096	$480,393,649	$493,957,968
Billing & Data Management	$5,618,748	$5,682,239	$5,746,449	$5,811,384	$5,877,052	$5,943,463	$6,010,624	$6,078,544	$6,147,232
SCE Fees	$1,843,057	$1,863,883	$1,884,943	$1,906,242	$1,927,781	$1,949,564	$1,971,593	$1,993,870	$2,016,400
Technical Services	$1,621,263	$1,653,688	$1,686,762	$1,720,497	$1,754,907	$1,790,005	$1,825,805	$1,862,321	$1,899,568
Staffing	$2,486,749	$2,536,484	$2,587,213	$2,638,958	$2,691,737	$2,745,571	$2,800,483	$2,856,492	$2,913,622
General & Administrative expenses	$485,698	$373,012	$380,473	$388,082	$415,844	$463,761	$411,836	$420,072	$428,474
Debt Service (CCE Bonds & Start-up Costs)	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760	$5,020,760
Contribution to Annual Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs	$59,222,818	$64,150,406	$64,999,852	$69,569,454	$74,410,714	$79,421,900	$85,192,109	$90,680,516	$96,610,926
Start-Up Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$2,160,255	$2,214,299	$2,270,081	$2,327,992	$2,386,645	$2,448,883	$2,511,282	$2,578,129	$2,647,881
Total Operating Costs	$477,719,842	$493,332,848	$505,214,835	$521,242,882	$537,689,880	$555,025,128	$573,149,587	$591,884,354	$611,642,831
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$477,719,842	$493,332,848	$505,214,835	$521,242,882	$537,689,880	$555,025,128	$573,149,587	$591,884,354	$611,642,831
Average CCE Rate ($/kWh)	$0.0932	$0.0952	$0.0964	$0.0984	$0.1003	$0.1024	$0.1046	$0.1068	$0.1091
Average SCE Generation Rate ($/kWh)	$0.0875	$0.0894	$0.0905	$0.0924	$0.0942	$0.0962	$0.0982	$0.1003	$0.1025
Total CCE Charges									
SCE Non-bypassable Charges	$15,714,145	$15,891,714	$16,071,291	$16,252,896	$16,436,554	$16,622,287	$16,810,119	$17,000,073	$17,192,174
CCE Revenue Requirement	$477,719,842	$493,332,848	$505,214,835	$521,242,882	$537,689,880	$555,025,128	$573,149,587	$591,884,354	$611,642,831
Total CCE Generation Revenue Requirement	$493,433,987	$509,224,562	$521,286,126	$537,495,779	$554,126,434	$571,647,416	$589,959,706	$608,884,428	$628,835,005
Bundled SCE Revenues	$1,147,726,447	$1,184,428,365	$1,218,321,871	$1,256,825,188	$1,296,461,281	$1,337,694,117	$1,380,454,747	$1,424,599,990	$1,470,543,601
Total CCE Customer Bill Revenues (Power Supply and Delivery	$1,192,597,201	$1,230,429,596	$1,265,227,870	$1,304,891,030	$1,345,714,588	$1,388,191,178	$1,432,245,827	$1,477,724,461	$1,525,066,089
Savings	**($44,870,755)**	**($46,001,231)**	**($46,905,999)**	**($48,065,842)**	**($49,253,307)**	**($50,497,060)**	**($51,791,080)**	**($53,124,471)**	**($54,522,488)**
Percent Savings	**-3.9%**	**-3.9%**	**-3.9%**	**-3.8%**	**-3.8%**	**-3.8%**	**-3.8%**	**-3.7%**	**-3.7%**
Cumulative Reserves	$396,821,695	$460,972,100	$525,971,952	$595,541,406	$669,952,120	$749,374,021	$834,566,129	$925,246,645	$1,021,857,571
Reserve Target									

SANBAG Community Choice Aggregation
Financial Proforma
Portfolio RPS

Load Data	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts												
Domestic	0	3,864	461,002	466,212	471,480	476,808	482,196	487,644	493,155	498,727	504,363	510,062
Commercial	0	33,205	48,808	49,359	49,917	50,481	51,051	51,628	52,212	52,802	53,398	54,002
Industrial	0	0	279	282	285	289	292	295	299	302	305	309
Lighting & Traffic Control	0	4,096	5,952	6,020	6,088	6,156	6,226	6,296	6,367	6,439	6,512	6,586
Agricultural	0	43	1,675	1,694	1,713	1,733	1,752	1,772	1,792	1,812	1,833	1,853
Total Customers	0	41,208	517,717	523,567	529,483	535,466	541,517	547,636	553,824	560,083	566,412	572,812
Energy Sales (MWh)												
Domestic	0	48	3,394,200	3,432,554	3,471,342	3,510,568	3,550,238	3,590,355	3,630,926	3,671,956	3,713,449	3,755,411
Commercial	0	80,550	2,361,973	2,388,663	2,415,655	2,442,952	2,470,558	2,498,475	2,526,708	2,555,259	2,584,134	2,613,335
Industrial	0	0	1,817,576	1,838,114	1,858,885	1,879,890	1,901,133	1,922,616	1,944,341	1,966,313	1,988,532	2,011,002
Lighting & Traffic Control	0	26,827	65,824	66,568	67,320	68,081	68,850	69,628	70,415	71,211	72,015	72,829
Agricultural	0	11,057	265,359	268,357	271,390	274,456	277,558	280,694	283,866	287,074	290,318	293,598
Total Energy Sales (MWh)	0	118,482	7,904,931	7,994,257	8,084,592	8,175,948	8,268,336	8,361,769	8,456,256	8,551,812	8,648,448	8,746,175

CCE Operating Costs	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Power Supply	$0	$5,817,828	$392,594,259	$406,937,383	$424,584,669	$439,255,432	$453,572,258	$469,213,463	$484,869,768	$501,024,271	$517,156,727	$532,166,740
Billing & Data Management	$0	$432,679	$7,764,423	$7,852,161	$7,940,891	$8,030,623	$8,121,369	$8,213,140	$8,305,949	$8,399,806	$8,494,724	$8,590,714
SCE Fees	$149,501	$1,939,421	$4,405,258	$2,575,617	$2,604,720	$2,634,152	$2,663,917	$2,694,018	$2,724,459	$2,755,244	$2,786,377	$2,817,862
Technical Services	$620,000	$740,000	$1,310,000	$1,356,600	$1,401,003	$1,465,319	$1,552,981	$1,669,111	$1,821,084	$2,019,393	$2,278,936	$2,620,965
Staffing	$90,000	$970,000	$2,488,333	$2,632,212	$2,684,856	$2,738,553	$2,793,324	$2,849,191	$2,906,175	$2,964,298	$3,023,584	$3,084,056
General & Administrative expenses	$90,000	$260,000	$350,000	$306,000	$312,120	$318,362	$399,730	$356,224	$337,849	$344,606	$351,498	$508,528
Debt Service (CCE Bonds & Start-up Costs)	$0	$1,170,882	$9,872,904	$9,872,904	$9,872,904	$9,872,904	$8,702,022	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140
Contribution to Annual Reserves	$0	$3,338,738	$30,998,387	$34,704,408	$37,070,123	$38,976,136						
New Programs	$0	$0	$0	$0	$0	$0	$41,905,466	$45,349,663	$47,332,068	$49,313,251	$51,226,918	$52,739,319
Start-Up Capital	$0	($10,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$4,748	$61,654	$2,429,498	$2,497,028	$2,590,204	$2,668,653	$2,740,027	$2,591,600	$2,672,908	$2,757,093	$2,841,505	$2,921,497
Total Operating Costs	$954,248	$4,731,202	$452,213,063	$468,734,314	$489,061,491	$505,960,135	$522,451,094	$540,467,549	$558,501,399	$577,109,102	$595,691,409	$612,980,821
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$954,248	$4,731,202	$452,213,063	$468,734,314	$489,061,491	$505,960,135	$522,451,094	$540,467,549	$558,501,399	$577,109,102	$595,691,409	$612,980,821
Average CCE Rate ($/kWh)		$0.0480	$0.0572	$0.0586	$0.0605	$0.0619	$0.0632	$0.0646	$0.0660	$0.0675	$0.0689	$0.0701
Average SCE Generation Rate ($/kWh)		$0.0571	$0.0681	$0.0698	$0.0720	$0.0737	$0.0752	$0.0769	$0.0786	$0.0803	$0.0820	$0.0834
Total CCE Charges												
SCE Non-bypassable Charges	$0	$1,000,043	$67,114,353	$67,872,745	$68,639,707	$69,415,336	$70,199,729	$25,793,617	$26,085,085	$26,379,847	$26,677,939	$26,979,400
CCE Revenue Requirement	$954,248	$4,731,202	$452,213,063	$468,734,314	$489,061,491	$505,960,135	$522,451,094	$540,467,549	$558,501,399	$577,109,102	$595,691,409	$612,980,821
Total CCE Generation Revenue Requirement	$954,248	$5,731,245	$519,327,416	$536,607,059	$557,701,198	$575,375,471	$592,650,823	$566,261,167	$584,586,484	$603,488,949	$622,369,348	$639,960,221
Bundled SCE Revenues	$0	$18,296,669	$1,351,759,556	$1,397,071,297	$1,447,722,341	$1,495,125,726	$1,542,903,988	$1,593,385,654	$1,644,803,337	$1,697,848,344	$1,751,837,051	$1,805,291,234
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$0	$17,573,193	$1,290,008,143	$1,332,448,522	$1,379,506,381	$1,423,972,783	$1,468,894,900	$1,516,233,071	$1,564,507,203	$1,614,302,648	$1,665,049,960	$1,715,512,382
Savings	**$0**	**$723,476**	**$61,751,414**	**$64,622,775**	**$68,215,960**	**$71,152,944**	**$74,009,088**	**$77,152,583**	**$80,296,134**	**$83,545,697**	**$86,787,091**	**$89,778,852**
Percent Savings		**4.0%**	**4.6%**	**4.6%**	**4.7%**	**4.8%**	**4.8%**	**4.8%**	**4.9%**	**4.9%**	**5.0%**	**5.0%**
Cumulative Reserves		$3,338,738	$34,337,125	$69,041,533	$106,111,656	$145,087,792	$186,993,258	$232,342,920	$279,674,988	$328,988,239	$380,215,157	$432,954,477
Reserve Target		$122,082,257										

SANBAG Community Choice Aggregation
Financial Proforma
Portfolio RPS

Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	515,826	521,655	527,550	533,511	539,540	545,636	551,802	558,037	564,343
Commercial	54,612	55,229	55,853	56,484	57,122	57,768	58,421	59,081	59,749
Industrial	312	316	319	323	327	330	334	338	0
Lighting & Traffic Control	6,660	6,735	6,812	6,889	6,966	7,045	7,125	7,205	0
Agricultural	1,874	1,896	1,917	1,939	1,960	1,983	2,005	2,028	0
Total Customers	579,285	585,831	592,451	599,145	605,916	612,763	619,687	626,689	624,092
Energy Sales (MWh)									
Domestic	3,797,847	3,840,763	3,884,163	3,928,054	3,972,442	4,017,330	4,062,726	4,108,635	4,155,062
Commercial	2,642,865	2,672,730	2,702,932	2,733,475	2,764,363	2,795,600	2,827,191	2,859,138	2,891,446
Industrial	2,033,727	2,056,708	2,079,949	2,103,452	2,127,221	2,151,259	2,175,568	2,200,152	2,225,013
Lighting & Traffic Control	73,652	74,484	75,326	76,177	77,038	77,909	78,789	79,679	80,580
Agricultural	296,916	300,271	303,664	307,095	310,566	314,075	317,624	321,213	324,843
Total Energy Sales (MWh)	8,845,007	8,944,955	9,046,033	9,148,254	9,251,629	9,356,172	9,461,897	9,568,817	9,676,944

CCE Operating Costs	2028	2029	2030	2031	2032	2033	2034	2035	2036
Power Supply	$548,658,172	$566,362,265	$580,875,978	$599,067,291	$617,551,808	$637,671,875	$658,180,175	$679,537,499	$701,816,578
Billing & Data Management	$8,687,789	$8,785,961	$8,885,243	$8,985,646	$9,087,184	$9,189,869	$9,293,715	$9,398,734	$9,504,939
SCE Fees	$2,849,703	$2,881,903	$2,914,468	$2,947,400	$2,980,704	$3,014,385	$3,048,446	$3,082,893	$3,117,728
Technical Services	$3,076,034	$3,688,515	$4,523,600	$5,678,260	$7,298,639	$9,608,019	$12,952,350	$17,875,422	$25,244,683
Staffing	$3,145,737	$3,208,652	$3,272,825	$3,338,281	$3,405,047	$3,473,148	$3,542,611	$3,613,463	$3,685,732
General & Administrative expenses	$415,698	$373,012	$380,473	$388,082	$470,844	$428,761	$411,836	$420,072	$428,474
Debt Service (CCE Bonds & Start-up Costs)	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140
Contribution to Annual Reserves									
New Programs	$54,606,116	$56,437,696	$57,523,867	$58,825,997	$59,624,763	$60,093,856	$59,551,620	$57,519,167	$53,160,470
Start-Up Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$3,006,230	$3,100,085	$3,179,383	$3,278,698	$3,382,215	$3,496,763	$3,618,585	$3,752,704	$3,903,698
Total Operating Costs	$631,976,619	$652,369,231	$669,086,976	$690,040,794	$711,332,344	$734,507,815	$758,130,477	$782,731,094	$808,393,442
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$631,976,619	$652,369,231	$669,086,976	$690,040,794	$711,332,344	$734,507,815	$758,130,477	$782,731,094	$808,393,442
Average CCE Rate ($/kWh)	$0.0715	$0.0729	$0.0740	$0.0754	$0.0769	$0.0785	$0.0801	$0.0818	$0.0835
Average SCE Generation Rate ($/kWh)	$0.0851	$0.0868	$0.0881	$0.0898	$0.0915	$0.0935	$0.0954	$0.0974	$0.0995
Total CCE Charges									
SCE Non-bypassable Charges	$26,881,816	$27,185,580	$27,492,777	$27,803,446	$28,117,624	$28,435,354	$28,756,673	$29,081,624	$29,410,246
CCE Revenue Requirement	$631,976,619	$652,369,231	$669,086,976	$690,040,794	$711,332,344	$734,507,815	$758,130,477	$782,731,094	$808,393,442
Total CCE Generation Revenue Requirement	$658,858,435	$679,554,811	$696,579,753	$717,844,240	$739,449,969	$762,943,169	$786,887,151	$811,812,718	$837,803,688
Bundled SCE Revenues	$1,861,813,136	$1,921,066,891	$1,977,048,485	$2,039,210,466	$2,102,947,810	$2,170,138,209	$2,239,109,425	$2,310,532,679	$2,384,548,303
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$1,768,318,453	$1,823,991,665	$1,877,096,124	$1,935,577,570	$1,995,573,559	$2,058,667,312	$2,123,460,293	$2,190,522,665	$2,259,978,845
Savings	**$93,494,683**	**$97,075,226**	**$99,952,361**	**$103,632,896**	**$107,374,251**	**$111,470,897**	**$115,649,132**	**$120,010,013**	**$124,569,457**
Percent Savings	**5.0%**	**5.1%**	**5.1%**	**5.1%**	**5.1%**	**5.1%**	**5.2%**	**5.2%**	**5.2%**
Cumulative Reserves	$487,560,592	$543,998,289	$601,522,155	$660,348,152	$719,972,916	$780,066,772	$839,618,392	$897,137,559	$950,298,029
Reserve Target									

SANBAG Community Choice Aggregation
Financial Proforma
Portfolio -50% Renewable

Load Data	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts												
Domestic	0	3,864	461,002	466,212	471,480	476,808	482,196	487,644	493,155	498,727	504,363	510,062
Commercial	0	33,205	48,808	49,359	49,917	50,481	51,051	51,628	52,212	52,802	53,398	54,002
Industrial	0	0	279	282	285	289	292	295	299	302	305	309
Lighting & Traffic Control	0	4,096	5,952	6,020	6,088	6,156	6,226	6,296	6,367	6,439	6,512	6,586
Agricultural	0	43	1,675	1,694	1,713	1,733	1,752	1,772	1,792	1,812	1,833	1,853
Total Customers	0	41,208	517,717	523,567	529,483	535,466	541,517	547,636	553,824	560,083	566,412	572,812
Energy Sales (MWh)												
Domestic	0	48	3,394,200	3,432,554	3,471,342	3,510,568	3,550,238	3,590,355	3,630,926	3,671,956	3,713,449	3,755,411
Commercial	0	80,550	2,361,973	2,388,663	2,415,655	2,442,952	2,470,558	2,498,475	2,526,708	2,555,259	2,584,134	2,613,335
Industrial	0	0	1,817,576	1,838,114	1,858,885	1,879,890	1,901,133	1,922,616	1,944,341	1,966,313	1,988,532	2,011,002
Lighting & Traffic Control	0	26,827	65,824	66,568	67,320	68,081	68,850	69,628	70,415	71,211	72,015	72,829
Agricultural	0	11,057	265,359	268,357	271,390	274,456	277,558	280,694	283,866	287,074	290,318	293,598
Total Energy Sales (MWh)	0	118,482	7,904,931	7,994,257	8,084,592	8,175,948	8,268,336	8,361,769	8,456,256	8,551,812	8,648,448	8,746,175

CCE Operating Costs	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Power Supply	$0	$6,032,329	$409,940,751	$421,359,492	$433,117,927	$445,534,854	$458,291,916	$471,270,295	$484,786,278	$498,634,313	$513,387,229	$528,761,063
Billing & Data Management	$0	$432,679	$7,764,423	$7,852,161	$7,940,891	$8,030,623	$8,121,369	$8,213,140	$8,305,949	$8,399,806	$8,494,724	$8,590,714
SCE Fees	$149,501	$1,939,421	$4,405,258	$2,575,617	$2,604,720	$2,634,152	$2,663,917	$2,694,018	$2,724,459	$2,755,244	$2,786,377	$2,817,862
Technical Services	$620,000	$740,000	$1,310,000	$1,356,600	$1,401,003	$1,465,319	$1,552,981	$1,669,111	$1,821,084	$2,019,393	$2,278,936	$2,620,965
Staffing	$90,000	$970,000	$2,488,333	$2,632,212	$2,684,856	$2,738,553	$2,793,324	$2,849,191	$2,906,175	$2,964,298	$3,023,584	$3,084,056
General & Administrative expenses	$90,000	$260,000	$350,000	$306,000	$312,120	$318,362	$399,730	$356,224	$337,849	$344,606	$351,498	$508,528
Debt Service (CCE Bonds & Start-up Costs)	$0	$1,170,882	$9,872,904	$9,872,904	$9,872,904	$9,872,904	$8,702,022	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140
Contribution to Annual Reserves	$0	$3,326,217	$29,715,629	$36,950,700	$45,960,681	$50,735,321						
New Programs	$0	$0	$0	$0	$0	$0	$55,821,177	$62,584,959	$67,362,454	$72,326,198	$76,289,957	$78,054,196
Start-Up Capital	$0	($10,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$4,748	$62,727	$2,516,230	$2,569,139	$2,632,871	$2,700,051	$2,763,625	$2,601,884	$2,672,490	$2,745,143	$2,822,657	$2,904,469
Total Operating Costs	$954,248	$4,934,254	$468,363,529	$485,474,825	$506,527,972	$524,030,140	$541,110,061	$559,769,962	$578,447,878	$597,720,141	$616,966,102	$634,872,994
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$954,248	$4,934,254	$468,363,529	$485,474,825	$506,527,972	$524,030,140	$541,110,061	$559,769,962	$578,447,878	$597,720,141	$616,966,102	$634,872,994
Average CCE Rate ($/kWh)		$0.0497	$0.0592	$0.0607	$0.0627	$0.0641	$0.0654	$0.0669	$0.0684	$0.0699	$0.0713	$0.0726
Average SCE Generation Rate ($/kWh)		$0.0571	$0.0681	$0.0698	$0.0720	$0.0737	$0.0752	$0.0769	$0.0786	$0.0803	$0.0820	$0.0834
Total CCE Charges												
SCE Non-bypassable Charges	$0	$1,000,043	$67,114,353	$67,872,745	$68,639,707	$69,415,336	$70,199,729	$25,793,617	$26,085,085	$26,379,847	$26,677,939	$26,979,400
CCE Revenue Requirement	$954,248	$4,934,254	$468,363,529	$485,474,825	$506,527,972	$524,030,140	$541,110,061	$559,769,962	$578,447,878	$597,720,141	$616,966,102	$634,872,994
Total CCE Generation Revenue Requirement	$954,248	$5,934,297	$535,477,882	$553,347,570	$575,167,680	$593,445,476	$611,309,791	$585,563,579	$604,532,963	$624,099,988	$643,644,041	$661,852,393
Bundled SCE Revenues	$0	$18,296,669	$1,351,759,556	$1,397,071,297	$1,447,722,341	$1,495,125,726	$1,542,903,988	$1,593,385,654	$1,644,803,337	$1,697,848,344	$1,751,837,051	$1,805,291,234
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$0	$17,776,245	$1,306,158,609	$1,349,189,033	$1,396,972,863	$1,442,042,787	$1,487,553,868	$1,535,535,483	$1,584,453,681	$1,634,913,687	$1,686,324,653	$1,737,404,554
Savings	**$0**	**$520,424**	**$45,600,947**	**$47,882,263**	**$50,749,479**	**$53,082,939**	**$55,350,120**	**$57,850,170**	**$60,349,655**	**$62,934,657**	**$65,512,398**	**$67,886,680**
Percent Savings		**2.8%**	**3.4%**	**3.4%**	**3.5%**	**3.6%**	**3.6%**	**3.6%**	**3.7%**	**3.7%**	**3.7%**	**3.8%**
Cumulative Reserves		$3,326,217	$33,041,846	$69,992,545	$115,953,226	$166,688,548	$222,509,725	$285,094,683	$352,457,137	$424,783,336	$501,073,293	$579,127,489
Reserve Target		$126,440,563										

SANBAG Community Choice Aggregation
Financial Proforma
Portfolio -50% Renewable

Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	515,826	521,655	527,550	533,511	539,540	545,636	551,802	558,037	564,343
Commercial	54,612	55,229	55,853	56,484	57,122	57,768	58,421	59,081	59,749
Industrial	312	316	319	323	327	330	334	338	0
Lighting & Traffic Control	6,660	6,735	6,812	6,889	6,966	7,045	7,125	7,205	0
Agricultural	1,874	1,896	1,917	1,939	1,960	1,983	2,005	2,028	0
Total Customers	579,285	585,831	592,451	599,145	605,916	612,763	619,687	626,689	624,092
Energy Sales (MWh)									
Domestic	3,797,847	3,840,763	3,884,163	3,928,054	3,972,442	4,017,330	4,062,726	4,108,635	4,155,062
Commercial	2,642,865	2,672,730	2,702,932	2,733,475	2,764,363	2,795,600	2,827,191	2,859,138	2,891,446
Industrial	2,033,727	2,056,708	2,079,949	2,103,452	2,127,221	2,151,259	2,175,568	2,200,152	2,225,013
Lighting & Traffic Control	73,652	74,484	75,326	76,177	77,038	77,909	78,789	79,679	80,580
Agricultural	296,916	300,271	303,664	307,095	310,566	314,075	317,624	321,213	324,843
Total Energy Sales (MWh)	8,845,007	8,944,955	9,046,033	9,148,254	9,251,629	9,356,172	9,461,897	9,568,817	9,676,944
CCE Operating Costs	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Power Supply	$544,480,927	$561,496,738	$580,875,978	$599,067,291	$617,551,808	$637,671,875	$658,180,175	$679,537,499	$701,816,578
Billing & Data Management	$8,687,789	$8,785,961	$8,885,243	$8,985,646	$9,087,184	$9,189,869	$9,293,715	$9,398,734	$9,504,939
SCE Fees	$2,849,703	$2,881,903	$2,914,468	$2,947,400	$2,980,704	$3,014,385	$3,048,446	$3,082,893	$3,117,728
Technical Services	$3,076,034	$3,688,515	$4,523,600	$5,678,260	$7,298,639	$9,608,019	$12,952,350	$17,875,422	$25,244,683
Staffing	$3,145,737	$3,208,652	$3,272,825	$3,338,281	$3,405,047	$3,473,148	$3,542,611	$3,613,463	$3,685,732
General & Administrative expenses	$415,698	$373,012	$380,473	$388,082	$470,844	$428,761	$411,836	$420,072	$428,474
Debt Service (CCE Bonds & Start-up Costs)	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140
Contribution to Annual Reserves									
New Programs	$81,374,841	$84,626,453	$81,419,830	$83,470,311	$85,029,490	$86,326,278	$86,627,708	$85,473,849	$82,031,664
Start-Up Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$2,985,344	$3,075,758	$3,179,383	$3,278,698	$3,382,215	$3,496,763	$3,618,585	$3,752,704	$3,903,698
Total Operating Costs	$654,547,213	$675,668,132	$692,982,939	$714,685,109	$736,737,071	$760,740,237	$785,206,566	$810,685,776	$837,264,636
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$654,547,213	$675,668,132	$692,982,939	$714,685,109	$736,737,071	$760,740,237	$785,206,566	$810,685,776	$837,264,636
Average CCE Rate ($/kWh)	$0.0740	$0.0755	$0.0766	$0.0781	$0.0796	$0.0813	$0.0830	$0.0847	$0.0865
Average SCE Generation Rate ($/kWh)	$0.0851	$0.0868	$0.0881	$0.0898	$0.0915	$0.0935	$0.0954	$0.0974	$0.0995
Total CCE Charges									
SCE Non-bypassable Charges	$26,881,816	$27,185,580	$27,492,777	$27,803,446	$28,117,624	$28,435,354	$28,756,673	$29,081,624	$29,410,246
CCE Revenue Requirement	$654,547,213	$675,668,132	$692,982,939	$714,685,109	$736,737,071	$760,740,237	$785,206,566	$810,685,776	$837,264,636
Total CCE Generation Revenue Requirement	$681,429,028	$702,853,712	$720,475,716	$742,488,554	$764,854,695	$789,175,591	$813,963,239	$839,767,400	$866,674,882
Bundled SCE Revenues	$1,861,813,136	$1,921,066,891	$1,977,048,485	$2,039,210,466	$2,102,947,810	$2,170,138,209	$2,239,109,425	$2,310,532,679	$2,384,548,303
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$1,790,889,047	$1,847,290,566	$1,900,992,087	$1,960,221,884	$2,020,978,286	$2,084,899,734	$2,150,536,382	$2,218,477,347	$2,288,850,040
Savings	**$70,924,090**	**$73,776,325**	**$76,056,398**	**$78,988,582**	**$81,969,524**	**$85,238,475**	**$88,573,044**	**$92,055,332**	**$95,698,263**
Percent Savings	**3.8%**	**3.8%**	**3.8%**	**3.9%**	**3.9%**	**3.9%**	**4.0%**	**4.0%**	**4.0%**
Cumulative Reserves	$660,502,330	$745,128,783	$826,548,613	$910,018,924	$995,048,414	$1,081,374,693	$1,168,002,401	$1,253,476,250	$1,335,507,915
Reserve Target									

SANBAG Community Choice Aggregation
Financial Proforma
Portfolio -100% Renewable

Load Data	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts												
Domestic	0	3,864	461,002	466,212	471,480	476,808	482,196	487,644	493,155	498,727	504,363	510,062
Commercial	0	33,205	48,808	49,359	49,917	50,481	51,051	51,628	52,212	52,802	53,398	54,002
Industrial	0	0	279	282	285	289	292	295	299	302	305	309
Lighting & Traffic Control	0	4,096	5,952	6,020	6,088	6,156	6,226	6,296	6,367	6,439	6,512	6,586
Agricultural	0	43	1,675	1,694	1,713	1,733	1,752	1,772	1,792	1,812	1,833	1,853
Total Customers	0	41,208	517,717	523,567	529,483	535,466	541,517	547,636	553,824	560,083	566,412	572,812
Energy Sales (MWh)												
Domestic	0	48	3,394,200	3,432,554	3,471,342	3,510,568	3,550,238	3,590,355	3,630,926	3,671,956	3,713,449	3,755,411
Commercial	0	80,550	2,361,973	2,388,663	2,415,655	2,442,952	2,470,558	2,498,475	2,526,708	2,555,259	2,584,134	2,613,335
Industrial	0	0	1,817,576	1,838,114	1,858,885	1,879,890	1,901,133	1,922,616	1,944,341	1,966,313	1,988,532	2,011,002
Lighting & Traffic Control	0	26,827	65,824	66,568	67,320	68,081	68,850	69,628	70,415	71,211	72,015	72,829
Agricultural	0	11,057	265,359	268,357	271,390	274,456	277,558	280,694	283,866	287,074	290,318	293,598
Total Energy Sales (MWh)	0	118,482	7,904,931	7,994,257	8,084,592	8,175,948	8,268,336	8,361,769	8,456,256	8,551,812	8,648,448	8,746,175
CCE Operating Costs	**2017 Jan - June**	**2017 July - Dec**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Power Supply	$0	$8,054,913	$536,576,640	$549,138,715	$562,272,029	$576,365,622	$590,588,068	$605,302,786	$620,418,253	$636,081,141	$652,426,823	$669,500,366
Billing & Data Management	$0	$432,679	$7,764,423	$7,852,161	$7,940,891	$8,030,623	$8,121,369	$8,213,140	$8,305,949	$8,399,806	$8,494,724	$8,590,714
SCE Fees	$149,501	$1,939,421	$4,405,258	$2,575,617	$2,604,720	$2,634,152	$2,663,917	$2,694,018	$2,724,459	$2,755,244	$2,786,377	$2,817,862
Technical Services	$620,000	$740,000	$1,310,000	$1,356,600	$1,401,003	$1,465,319	$1,552,981	$1,669,111	$1,821,084	$2,019,393	$2,278,936	$2,620,965
Staffing	$90,000	$970,000	$2,488,333	$2,632,212	$2,684,856	$2,738,553	$2,793,324	$2,849,191	$2,906,175	$2,964,298	$3,023,584	$3,084,056
General & Administrative expenses	$90,000	$260,000	$350,000	$306,000	$312,120	$318,362	$399,730	$356,224	$337,849	$344,606	$351,498	$508,528
Debt Service (CCE Bonds & Start-up Costs)	$0	$1,170,882	$9,872,904	$9,872,904	$9,872,904	$9,872,904	$8,702,022	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140
Contribution to Annual Reserves	$0	$2,850,249	$26,266,804	$36,876,500	$50,070,502	$57,787,103						
New Programs	$0	$0	$0	$0	$0	$0	$65,915,629	$75,867,468	$83,975,321	$92,210,104	$99,661,146	$104,451,184
Start-Up Capital	$0	($10,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$4,748	$72,840	$3,149,410	$3,208,035	$3,278,641	$3,354,204	$3,425,106	$3,272,046	$3,350,650	$3,432,377	$3,517,855	$3,608,165
Total Operating Costs	$954,248	$6,490,984	$592,183,773	$613,818,744	$640,437,666	$662,566,843	$684,162,147	$707,755,124	$731,370,880	$755,738,110	$780,072,083	$802,712,980
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$954,248	$6,490,984	$592,183,773	$613,818,744	$640,437,666	$662,566,843	$684,162,147	$707,755,124	$731,370,880	$755,738,110	$780,072,083	$802,712,980
Average CCE Rate ($/kWh)		$0.0628	$0.0749	$0.0768	$0.0792	$0.0810	$0.0827	$0.0846	$0.0865	$0.0884	$0.0902	$0.0918
Average SCE Generation Rate ($/kWh)		$0.0571	$0.0681	$0.0698	$0.0720	$0.0737	$0.0752	$0.0769	$0.0786	$0.0803	$0.0820	$0.0834
Total CCE Charges												
SCE Non-bypassable Charges	$0	$1,000,043	$67,114,353	$67,872,745	$68,639,707	$69,415,336	$70,199,729	$25,793,617	$26,085,085	$26,379,847	$26,677,939	$26,979,400
CCE Revenue Requirement	$954,248	$6,490,984	$592,183,773	$613,818,744	$640,437,666	$662,566,843	$684,162,147	$707,755,124	$731,370,880	$755,738,110	$780,072,083	$802,712,980
Total CCE Generation Revenue Requirement	$954,248	$7,491,027	$659,298,126	$681,691,489	$709,077,373	$731,982,179	$754,361,876	$733,548,742	$757,455,965	$782,117,956	$806,750,022	$829,692,380
Bundled SCE Revenues	$0	$18,296,669	$1,351,759,556	$1,397,071,297	$1,447,722,341	$1,495,125,726	$1,542,903,988	$1,593,385,654	$1,644,803,337	$1,697,848,344	$1,751,837,051	$1,805,291,234
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$0	$19,332,976	$1,429,978,853	$1,477,532,952	$1,530,882,557	$1,580,579,491	$1,630,605,953	$1,683,520,646	$1,737,376,684	$1,792,931,655	$1,849,430,634	$1,905,244,541
Savings	**$0**	**($1,036,307)**	**($78,219,296)**	**($80,461,656)**	**($83,160,215)**	**($85,453,765)**	**($87,701,965)**	**($90,134,992)**	**($92,573,347)**	**($95,083,311)**	**($97,593,583)**	**($99,953,307)**
Percent Savings		**-5.7%**	**-5.8%**	**-5.8%**	**-5.7%**	**-5.7%**	**-5.7%**	**-5.7%**	**-5.6%**	**-5.6%**	**-5.6%**	**-5.5%**
Cumulative Reserves		$2,850,249	$29,117,053	$65,993,553	$116,064,055	$173,851,157	$239,766,786	$315,634,254	$399,609,575	$491,819,679	$591,480,825	$695,932,009
Reserve Target		$158,257,831										

SANBAG Community Choice Aggregation
Financial Proforma
Portfolio -100% Renewable

Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	515,826	521,655	527,550	533,511	539,540	545,636	551,802	558,037	564,343
Commercial	54,612	55,229	55,853	56,484	57,122	57,768	58,421	59,081	59,749
Industrial	312	316	319	323	327	330	334	338	0
Lighting & Traffic Control	6,660	6,735	6,812	6,889	6,966	7,045	7,125	7,205	0
Agricultural	1,874	1,896	1,917	1,939	1,960	1,983	2,005	2,028	0
Total Customers	579,285	585,831	592,451	599,145	605,916	612,763	619,687	626,689	624,092
Energy Sales (MWh)									
Domestic	3,797,847	3,840,763	3,884,163	3,928,054	3,972,442	4,017,330	4,062,726	4,108,635	4,155,062
Commercial	2,642,865	2,672,730	2,702,932	2,733,475	2,764,363	2,795,600	2,827,191	2,859,138	2,891,446
Industrial	2,033,727	2,056,708	2,079,949	2,103,452	2,127,221	2,151,259	2,175,568	2,200,152	2,225,013
Lighting & Traffic Control	73,652	74,484	75,326	76,177	77,038	77,909	78,789	79,679	80,580
Agricultural	296,916	300,271	303,664	307,095	310,566	314,075	317,624	321,213	324,843
Total Energy Sales (MWh)	8,845,007	8,944,955	9,046,033	9,148,254	9,251,629	9,356,172	9,461,897	9,568,817	9,676,944
CCE Operating Costs	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Power Supply	$686,649,590	$705,191,857	$724,371,278	$744,095,507	$764,079,831	$784,837,086	$806,863,453	$829,354,073	$852,432,239
Billing & Data Management	$8,687,789	$8,785,961	$8,885,243	$8,985,646	$9,087,184	$9,189,869	$9,293,715	$9,398,734	$9,504,939
SCE Fees	$2,849,703	$2,881,903	$2,914,468	$2,947,400	$2,980,704	$3,014,385	$3,048,446	$3,082,893	$3,117,728
Technical Services	$3,076,034	$3,688,515	$4,523,600	$5,678,260	$7,298,639	$9,608,019	$12,952,350	$17,875,422	$25,244,683
Staffing	$3,145,737	$3,208,652	$3,272,825	$3,338,281	$3,405,047	$3,473,148	$3,542,611	$3,613,463	$3,685,732
General & Administrative expenses	$415,698	$373,012	$380,473	$388,082	$470,844	$428,761	$411,836	$420,072	$428,474
Debt Service (CCE Bonds & Start-up Costs)	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140	$7,531,140
Contribution to Annual Reserves									
New Programs	$111,536,551	$118,837,766	$120,409,440	$126,656,695	$132,538,397	$139,540,476	$144,784,360	$149,227,421	$152,008,749
Start-Up Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$3,696,188	$3,794,233	$3,896,859	$4,003,839	$4,114,855	$4,232,589	$4,362,001	$4,501,787	$4,656,776
Total Operating Costs	$827,588,430	$854,293,040	$876,185,325	$903,624,850	$931,506,641	$961,855,473	$992,789,911	$1,025,005,004	$1,058,610,460
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$827,588,430	$854,293,040	$876,185,325	$903,624,850	$931,506,641	$961,855,473	$992,789,911	$1,025,005,004	$1,058,610,460
Average CCE Rate ($/kWh)	$0.0936	$0.0955	$0.0969	$0.0988	$0.1007	$0.1028	$0.1049	$0.1071	$0.1094
Average SCE Generation Rate ($/kWh)	$0.0851	$0.0868	$0.0881	$0.0898	$0.0915	$0.0935	$0.0954	$0.0974	$0.0995
Total CCE Charges									
SCE Non-bypassable Charges	$26,881,816	$27,185,580	$27,492,777	$27,803,446	$28,117,624	$28,435,354	$28,756,673	$29,081,624	$29,410,246
CCE Revenue Requirement	$827,588,430	$854,293,040	$876,185,325	$903,624,850	$931,506,641	$961,855,473	$992,789,911	$1,025,005,004	$1,058,610,460
Total CCE Generation Revenue Requirement	$854,470,246	$881,478,620	$903,678,102	$931,428,295	$959,624,265	$990,290,826	$1,021,546,584	$1,054,086,628	$1,088,020,706
Bundled SCE Revenues	$1,861,813,136	$1,921,066,891	$1,977,048,485	$2,039,210,466	$2,102,947,810	$2,170,138,209	$2,239,109,425	$2,310,532,679	$2,384,548,303
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$1,963,930,264	$2,025,915,475	$2,084,194,473	$2,149,161,625	$2,215,747,856	$2,286,014,970	$2,358,119,727	$2,432,796,575	$2,510,195,863
Savings	**($102,117,127)**	**($104,848,584)**	**($107,145,989)**	**($109,951,159)**	**($112,800,046)**	**($115,876,760)**	**($119,010,301)**	**($122,263,897)**	**($125,647,560)**
Percent Savings	**-5.5%**	**-5.5%**	**-5.4%**	**-5.4%**	**-5.4%**	**-5.3%**	**-5.3%**	**-5.3%**	**-5.3%**
Cumulative Reserves	$807,468,561	$926,306,327	$1,046,715,766	$1,173,372,462	$1,305,910,858	$1,445,451,335	$1,590,235,694	$1,739,463,115	$1,891,471,864
Reserve Target									

Appendix C – ICP Excluding Riverside County

Introduction

Riverside County (County) has already been exploring developing a Community Choice Aggregation Program for the unincorporated Riverside County separate from ICP. The County is interested in hiring a third party to operate the CCA on behalf of the County, rather than joining a Joint Power Agreement with other public entities.

This Appendix provides the estimated cost impact of Riverside County not joining the ICP CCA given the 50% Renewable Scenario.

Analysis

Based on the data received by SCE, Riverside County load makes up approximately 9 percent of the total ICP load. This scenario was therefore modeled assuming the ICP load and the number of customers would be reduced by 9 percent.

Power supply, data management, billing, SCE charges and non-bypassable charges were reduced to reflect the lower load and number of customers. It was assumed that ICP without the County would still need the same number of staff, operating and administrative costs, and consultant services as the 9 percent reduction in load would not significantly reduce the level of effort required in these areas.

Results

Based on the analysis, the overall savings to ICP customers are reduced from 3.7 percent to 3.2 percent. Savings are reduced largely because the fixed costs needed to operate the CCA remain nearly unchanged while the generation revenues decrease with the load. Table C-1 provides a summary of the projected cost impacts and savings for 2018, while the following pages provide the proforma for the ICP without County analysis for all three power supply scenarios.

Table C-1
Savings Comparison Under the 50% Renewable Scenario

	ICP	ICP without Riverside County
Power Supply Expenses	$738.9 million	$643.2 million
Non-Power Supply Expenses	$104.1 million	$103.1 million
SCE Non-bypassable Charges	$120.3 million	$105.4 million
Total	$963.3 million	$851.7 million
Bundled SCE Rate	$2,492.1 million	$2,173.2 million
CCA Total Bill	$2,384.4 million	$2,104.1 million
Savings	$93.7 million	$69.0 million
	3.8%	3.2%

Appendix D – Glossary

aMW: Average annual Megawatt. A unit of energy output over a year that is equal to the energy produced by the continuous operation of one megawatt of capacity over a period of time (8,760 megawatt-hours).

Basis Difference (Natural Gas): The difference between the price of natural gas at the Henry Hub natural gas distribution point in Erath, Louisiana, which serves as a central pricing point for natural gas futures, and the natural gas price at another hub location (such as for Southern California).

Buckets: Buckets 1-3 refer to different types of renewable energy contracts according to the Renewable Portfolio Standards requirements. Bucket 1 are traditional contracts for delivery of electricity directly from a generator within or immediately connected to California. These are the most valuable and make up the majority of the RECS that are required for LSEs to be RPS compliant. Buckets 2 and 3 have different levels of intermediation between the generation and delivery of the energy from the generating resources.

Bundled Customers: Electricity customers who receive all their services (transmission, distribution and supply) from the Investor-Owned Utility.

CAISO: The California Independent System Operator. The organization responsible for managing the electricity grid and system reliability within the former service territories of the three California IOUs.

California Clean Power (CCP): A private company providing wholesale supply and other services to CCAs.

California Energy Commission (CEC): The state regulatory agency with primary responsibility for enforcing the Renewable Portfolio Standards law as well as a number of other, electric-industry related rules and policies.

California Public Utilities Commission (CPUC): The state agency with primary responsibility for regulating IOUs, as well as Direct Access (ESP) and CCA entities.

Capacity Factor: the ratio of an electricity generating resource's actual output over a period of time to its potential output if it were possible to operate at full nameplate capacity continuously over the same period. Intermittent renewable resources, like wind and solar, typically have lower capacity factors than traditional fossil fuel plants because the wind and sun do not blow or shine consistently.

CCEAC: Community Choice Energy Advisory Committee - a committee formed to advise the City of Davis on the best options for pursuing a CCA.

Climate Zone: A geographic area with distinct climate patterns necessitating varied energy demands for heating and cooling.

Coachella Valley Association of Governments (CVAG): CVAG is the regional planning agency coordinating government services in the Coachella Valley. It includes 10 Cities, Riverside County, the Agua Caliente Band of Cahuilla Indians and the Cabazon Band of Mission Indians as members.

Coincident Peak: Demand for electricity among a group of customers that coincides with peak total demand on the system.

Community Choice Aggregation: Method available through California law to allow Cities and Counties to aggregate their citizens and become their electric generation provider.

Community Choice Energy: A City, County or Joint Powers Agency procuring wholesale power to supply to retail customers.

Community Choice Partners: A private company providing services to CCAs in California.

Congestion Revenue Rights (CRRs): Financial rights that are allocated to Load Serving Entities to offset differences between the prices where their generation is located and the price that they pay to serve their load. These rights may also be bought and sold through an auction process. CRRs are part of the CAISO market design.

Demand Response (DR): Electric customers who have a contract to modify their electricity usage in response to requests from a utility or other electric entity. Typically, will be used to lower demand during peak energy periods, but may be used to raise demand during periods of excess supply.

Direct Access: Large power consumers which have opted to procure their wholesale supply independently of the IOUs through an Electricity Service Provider.

EEI (Edison Electric Institute) Agreement: A commonly used enabling agreement for transacting in wholesale power markets.

Electric Service Providers (ESP): An alternative to traditional utilities. They provide electric services to retail customers in electricity markets that have opened their retail electricity markets to competition. In California the Direct Access program allows large electricity customers to opt-out of utility-supplied power in favor of ESP-provided power. However, there is a cap on the amount of Direct Access load permitted in the state.

Electric Tariffs: The rates and terms applied to customers by electric utilities. Typically have different tariffs for different classes of customers and possibly for different supply mixes.

Enterprise Model: When a City or County establish a CCA by themselves as an enterprise within the municipal government.

Federal Tax Incentives: There are two Federal tax incentive programs. The Investment Tax Credit (ITC) provides payments to solar generators. The Production Tax Credit (PTC) provides payments to wind generators.

Feed-in Tariff: A tariff that specifies what generators who are connected to the distribution system are paid.

Forward Prices: Prices for contracts that specify a future delivery date for a commodity or other security. There are active, liquid forward markets for electricity to be delivered at a number of Western electricity trading hubs, including NP15 which corresponds closely to the price location which the City of Davis will pay to supply its load.

Implied Heat Rate: A calculation of the day-ahead electric price divided by the day-ahead natural gas price. Implied heat rate is also known as the 'break-even natural gas market heat rate,' because only a natural gas generator with an operating heat rate (measure of unit efficiency) below the implied heat rate value can make money by burning natural gas to generate power. Natural gas plants with a higher operating heat rate cannot make money at the prevailing electricity and natural gas prices.

Inland Choice Power (ICP): The name of the proposed CCA that would serve the ICP areas of CVAG, SANBAG, and WRCOG.

Integrated Resource Plan: A utility's plan for future generation supply needs.

Investor-Owned Utility: For profit regulated utilities. Within California there are three IOUs - Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric.

ISDA (International Swaps and Derivatives Association): Popular form of bilateral contract to facilitate wholesale electricity trading.

Joint Powers Agency (JPA): A legal entity comprising two or more public entities. The JPA provides a separation of financial and legal responsibility from its member entities.

Lancaster Choice Energy (LCE): The most recent California CCA to go-live, exclusively serving the City of Lancaster in Southern California.

LEAN Energy (Local Energy Aggregation Network): A not-for-profit organization dedicated to expanding Community Choice Aggregation nationwide.

Load Forecast: A forecast of expected load over some future time horizon. Short-term load forecasts are used to determine what supply sources are needed. Longer-term load forecasts are used for budgeting and long-term resource planning.

Marginal Unit: An additional unit of power generation to what is currently being produced. At and electric power plant, the cost to produce a marginal unit is used to determine the cost of increasing power generation at that source.

MCE: Formerly Marin Clean Energy - the first CCA in California serving Cities within and the Counties of Marin and Napa.

MRTU: CAISO's Market Redesign and Technology Upgrade. The redesigned, nodal (as opposed to zonal) market that went live in April of 2009.

Net Energy Metering: The program and rates that pertain to electricity customers who also generate electricity, typically from rooftop solar panels.

Non-Coincident Peak: Energy demand by a customer during periods that do not coincide with maximum total system load.

Non-Renewable Power: Electricity generated from non-renewable sources or that does not come with a Renewable Energy Credit (REC).

NP15: Refers to a wholesale electricity pricing hub - North of Path 15 - which roughly corresponds to PG&E's service territory. Forward and Day-Ahead power contracts for Northern California typically provide for delivery at NP15. It is not a single location, but an aggregate based on the locations of all the generators in the region.

On-Bill Repayment (OBR): Allows electric customers to pay for financed improvements such as energy efficiency measures through monthly payments on their electricity bills.

Operate on the Margin: Operation of a business or resource at the limit of where it is profitable.

Opt-Out: Community Choice Aggregation is, by law, an opt-out program. Customers within the borders of a CCA are automatically enrolled within the CCA unless they proactively opt-out of the program.

Power Cost Indifference Adjustment (PCIA): A charge applied to customers who leave IOU service to become Direct Access or CCA customers. The charge is meant to compensate the IOU for costs that it has previously incurred to serve those customers.

PPA (Power Purchase Agreement): The standard term for bilateral supply contracts in the electricity industry.

Renewable Energy Credits (RECs): The renewable attributes from RPS-qualified resources which must be registered and retired to comply with RPS standards.

Resource Adequacy (RA): The requirement that a Load-Serving Entity own or procure sufficient generating capacity to meet its peak load plus a contingency amount (15 percent in California) for each month.

RPS (Renewable Portfolio Standards): The state-based requirement to procure a certain percentage of load from RPS-certified renewable resources.

San Bernardino Associated Governments (SANBAG): SANBAG is the council of government and transportation planning agency for San Bernardino County. SANBAG's members include 24 cities and San Bernardino County.

Scheduling Coordinator: An entity that is approved to interact directly with CAISO to schedule load and generation. All CAISO participants must be or have an SC.

Scheduling Agent: A person or service that forecasts and monitors short term system load requirements and meets these demands by scheduling power resource to meet that demand.

Sonoma Clean Power (SCP): A CCA serving Sonoma County and Sonoma County Cities.

Spark Spread: The theoretical grow margin of a gas-fired power plant from selling a unit of electricity, having bought the fuel required to produce this unit of electricity. All other costs (capital, operation and maintenance, etc.) must be covered from the spark spread.

Supply Stack: Refers to the generators within a region, stacked up according to their marginal cost to supply energy. Renewables are on the bottom of the stack and peaking gas generators on the top. Used to provide insights into how the price of electricity is likely to change as the load changes.

ICP: Refers collectively to the three councils of governments: Coachella Valley Association of Governments (CVAG), San Bernardino Associated Governments (SANBAG), and Western Riverside Council of Governments (WRCOG).

Weather Adjusted: Normalizing energy use data based on differences in the weather during the time of use. For instance, energy use is expected to be higher on extremely hot days when air conditioning is in higher demand than on days with comfortable temperature. Weather adjustment normalizes for this variation.

Western Electric Coordinating Council (WECC): The organization responsible for coordinating planning and operation on the Western electric grid.

Western Riverside Council of Governments (WRCOG): WRCOG is the council of governments in Western Riverside County consisting of 17 Cities, Riverside County, and the Morongo Band of Mission Indians.

Wholesale Power: Large amounts of electricity that are bought and sold by utilities and other electric companies in bulk at specific trading hubs. Quantities are measured in MWs, and a standard wholesale contract is for 25 MW for a month during heavy-load or peak hours (7am to 10 pm, Mon-Sat), or light-load or off-peak hours (all the other hours).

WSPP (Western States Power Pool) Agreement: Common, standardized enabling agreement to transact in the wholesale power markets.

Appendix E – Inland Choice Power Launch Schedule

Legend: COG or JPA Action · CCA Team Process · Non-negotiable External Timeline

		2017												2018	
		January	February	March	April	May	June	July	August	Septembe	October	Novembe	Decembe	January	February
ICP Formation & Staffing	**CVAG, WRCOG, SANBAG form and join Inland Choice Power (ICP)**														
	Setup ICP Governance Board														
	Hire Executive Director and key staff for pre-operations														
	Hire Staff														
CPUC Implementation Plan & Registration	Develop Implementation Plan														
	ICP approves & files Implementation Plan														
	CPUC certifies implementation plan[1]														
	Submit Surety Bond to CPUC and copy to SCE[2]														
	JPA submits registration package to CPUC[3]														
Power Supply and Data Management	Develop RFP for Power Supply & Data Management														
	Issue power supply and data mgmt RFP and receive responses														
	Review, select, negotiate power supply and data management providers														
	ICP executes Power Supply & Data Management Contracts														
	ICP finalizes initial rates														
Financing	Prepare financing plan														
	Negotiate Financing & Line of Credit														
	ICP Approves Financing Agreement														
	Transaction testing														
SCE Process	ICP negotiates notice of start date with SCE														
	Establish credit worthiness with IOU														
	SCE Forms[4]														
	Negotiate opt-out notification & processing responsibility (CCA or SCE)														
	Determine Annual Joint Rate Comparison (JRC) lead (CCA or SCE)														
	ICP executes service agreement with IOU														
	SCE starts six month preparation for CCA launch														
	Test Electronic Data Exchange with SCE														
	Create and validate mass enrollment account list														
	Update SCE on opt-out list														
Customer Communication	Customer outreach														
	Opt Out notice 1														
	Opt Out Notice 2														
	Automatic enrollment of customers that have not opted out														
	Opt Out notice 3														
	Customers switched to CCA service at scheduled meter read														
	Opt Out Notice 4														

[1]Represents maximum possible duration for CPUC review of implementation plan, [2]Contingent on completing financing agreement, [3]Contingent on completion of service agreement with SCE

[4]SCE forms include: "Participant Information Form", "Credit Application & Security Form", "EDI Trading Partner Agreement", "EDI Partner Profiles form", "MFT Server Form", scheduling coordinator letter, non-disclosure agreement, and a declaration by JPA board.

Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **Potential WRCOG Agency Office Relocation**

Contacts: **Rick Bishop, Executive Director, bishop@wrcog.cog.ca.us, (951) 955-8303**

Date: **February 6, 2017**

The purpose of this item is to *provide updated information regarding the WRCOG office relocation and to seek direction from the Executive Committee in finalizing the Agency's relocation.*

Requested Action:

1. Approve staff's recommendation to relocate the WRCOG offices to the Pacific Premiere Bank building and seek a 10-year lease agreement with the County of Riverside.

WRCOG currently occupies 5,532 square feet at the County Administrative Center (CAC), and space is at a premium with up to 30 staff/consultants/interns onsite at any given time. Options for Agency relocation have been discussed with the Administration & Finance and Executive Committees. This report provides additional information regarding a potential location based on recent discussions among WRCOG and staff from the Riverside County Economic Development Agency (EDA).

Update

On January 9, 2017, staff presented the Executive Committee with options for relocating WRCOG's offices. The Executive Committee approved a recommendation from the Administration & Finance Committee for the Agency to move to the Citrus Towers building (3390 University Avenue) in downtown Riverside. One of the major reasons the Citrus Towers building was selected was that upfront costs (tenant improvements) of moving to this location would be covered, and then paid back over the term of the 10-year lease. Several months earlier, reviewing a recommendation to move the Agency to the Pacific Premiere Bank Building (3403 10th Street), the Executive Committee had stated that it was not in favor of having WRCOG pay upfront costs for tenant improvements, and directed staff to examine other options.

Since the Executive Committee's action to approve a relocation to Citrus Towers, staff has had additional meetings with County staff regarding the Pacific Premiere Bank building, which is owned by County EDA. As part of these discussions the County has indicated it would be able to cover the costs of the upfront tenant improvements, so long as the costs could be made up over the course of the 10-year lease.

Using the same \$70/square foot cost estimate for tenant improvements that the owner from Citrus Towers granted WRCOG, staff estimates that improvement costs for the Pacific Premiere Bank building to be \$746,410 (\$70/square foot multiplied by the 10,663 total available square feet). Payback of improvements would occur by adding in this total cost (\$746,410) to the lease on a square foot basis, paid over a 10 year period. Dividing the total cost over a ten-year period adds an additional \$0.58 per square foot, increasing the cost of Pacific Premiere Bank from \$2.02 per sq. ft. to \$2.60 per sq. ft. However, with both building owners now covering the tenant improvements up front, an "apples to apples" comparison of the two buildings shows a considerable savings to the Agency if it were to locate to the Pacific Premiere Bank Building.

Pacific Premiere Bank:	$2.60 sq. ft.	$1,766,273 – Five Year Cost	$3,813,868 – Ten Year Cost
Citrus Towers:	$3.10 sq. ft.	$2,092,906 – Five Year Cost	$4,453,456 – Ten Year Cost

Comparing the cost of the two leases with the new information, the Pacific Premiere Bank location after five years is $326,633 less expensive, and after ten years is $639,588 less expensive. Further, County staff has indicated that it could meet the construction schedule agreed to by the Citrus Towers owner, which could result in having WRCOG occupy the new building within a 4 to 6 month period. Earlier it was believed that the construction time at the Pacific Premiere Bank building would be longer, which was also a concern of the Executive Committee in making its previous decision.

Based on this new information, staff recommends that the Executive Committee direct staff to enter into an agreement with the County for a 10-year lease at the Pacific Premiere Bank Building.

Prior Actions:

January 9, 2017: The Executive Committee approved that WRCOG relocate its offices to the Citrus Towers building located at 3390 University Ave., Riverside.

December 14, 2016: The Administration & Finance Committee recommended that WRCOG relocate its offices to the Citrus Tower building located at 3390 University Ave., Riverside.

August 1, 2016: The Executive Committee directed staff to 1) request the County to hold the space for another 60 days; 2) circle back with WMWD for further discussions; 3) explore the purchase of a building in an expanded area beyond a half-block radius; and 4) revisit options for the 2nd floor within this building.

July 11, 2016: The Administration & Finance Committee recommended that the Executive Committee approve the relocation of the Agency to space within a County-owned building at 3404 10th Street, Riverside.

Fiscal Impact:

WRCOG estimates the cost of relocating to the Pacific Premiere Bank Building will be $3,813,868 (excluding an estimated $312,500 for furniture) over a 10-year period. Costs will be reflected in future annual budgets.

Attachment:

None.

Western Riverside Council of Governments
Executive Committee

Staff Report

Subject: **Transportation Uniform Mitigation Fee (TUMF) Program Activities Update**

Contact: **Christopher Gray, Director of Transportation, gray@wrcog.cog.ca.us, (951) 955-8304**

Date: **February 6, 2017**

The purpose of this item is to *provide Committee members an update on the progress of the 2017 TUMF Nexus Study Update.*

Requested Action:

1. Receive and file.

WRCOG's Transportation Uniform Mitigation Fee (TUMF) Program is a regional fee program designed to provide transportation and transit infrastructure that mitigates the impact of new growth in Western Riverside County. Each of WRCOG's member jurisdictions and the March JPA participates in the Program through an adopted ordinance, collects fees from new development, and remits the fees to WRCOG. WRCOG, as administrator of the TUMF Program, allocates TUMF to the Riverside County Transportation Commission (RCTC), groupings of jurisdictions – referred to as TUMF Zones – based on the amounts of fees collected in these groups, and the Riverside Transit Agency (RTA). The TUMF Nexus Study is intended to satisfy the requirements of California Government Code Chapter 5 Section 66000-66008 (also known as the California Mitigation Fee Act) which governs imposing development impact fees in California. The Study establishes a nexus or reasonable relationship between the development impact fee's use and the type of project for which the fee is required. The TUMF Program is a development impact fee and is subject to the California Mitigation Fee Act (AB 1600, Govt. Code § 6600), which mandates that a Nexus Study be prepared to demonstrate a reasonable and rational relationship between the fee and the proposed improvements for which the fee is used. AB 1600 also requires the regular review and update of the Program and Nexus Study to ensure the validity of the Program. The last TUMF Nexus Study update was adopted in October 2009.

TUMF Nexus Study update

Staff, in coordination with TUMF consultant Parsons Brinckerhoff, is preparing the draft 2017 TUMF Nexus Study, which is expected to be released for review and comment in February. Additionally, staff is available to meet and discuss the Nexus Study at the request of any stakeholder.

Staff have been presenting the key components and comments received by stakeholders regarding the Nexus Study update to the Committee structure. Some items that staff identified as key components include the following:

Proposed fee levels: With the Executive Committee taking action to delay finalizing the Nexus Study in September 2016, staff and the TUMF consultant have reviewed and updated all components of the technical document. Components of the Nexus Study that have been updated include:

- Growth Forecast – Adopted in April 2016 by the SCAG Regional Council, the updated demographic data show that the subregion will add more than 650,000 people, 250,000 households and 400,000 jobs.

- TUMF Network – WRCOG and member jurisdictions undertook a comprehensive review of the facilities included in the TUMF Program to ensure that all facilities warrant inclusion in the Program.
- Fee calculation methodology – WRCOG and TUMF consultant used a Vehicle Miles Travel (VMT) approach for fee calculations of residential and non-residential land-use types. This approach has not previously been utilized in past editions of the Nexus Study.
- Data sources – In response to the release of the draft Nexus Study in summer 2015, WRCOG received comments regarding the use of outdated studies for the employee to square footage conversion. Staff reviewed requested studies and included more recent data from SCAG and Riverside County.

With the exception of the retail land use fee, there are modest increases to the remaining land use types.

Land Use Type	Current Fee	2017 TUMF Nexus Study – Proposed Fee	% Change From Current Fee
Single-Family Residential	**$8,873**	**$9,729**	**10%**
Multi-Family Residential	**$6,231**	**$6,336**	**2%**
Industrial	**$1.73**	**$1.83**	**6%**
Retail	**$10.49**	**$12.71**	**21%**
Service	**$4.19**	**$4.71**	**12%**

Phasing options: In September 2016, WRCOG convened an Ad Hoc Committee with the goal of ultimately selecting a preferred option to recommend to the Committee structure for finalizing the Nexus Study. The Ad Hoc Committee was provided with all components of the Nexus Study, including TUMF Network facilities, growth forecast data, and a fee comparison study. During meetings held in late 2016, WRCOG informed the Ad Hoc Committee that staff, in coordination with member jurisdictions, a comprehensive review of the TUMF Network was conducted in order to ensure all facilities met the criteria for inclusion in the TUMF Program. As a result, the Ad Hoc Committee directed staff to provide phase-in options with a revised TUMF Network.

The Ad Hoc Committee met for a third time on January 23, 2017, to review a set of potential phase-in options developed in order to finalize the TUMF Nexus Study. The Ad Hoc Committee recommended that the Committee structure review a 2-year retail fee freeze and subsequent 2-year phase in, plus a 2-year single-family residential phase-in option for implementation. Members of the Ad Hoc Committee discussed affordable housing and the importance of retail development for jurisdictions. The Ad Hoc Committee also discussed the implications of any phase-in option that is approved and how any loss to the Program would be made up. Revenue loss resulting from any phase-in can be made up through various options, including project savings in the delivery of TUMF facilities.

Impact of keeping the 2009 Nexus Study: As the body that presides over the policy decisions of the Program, the Executive Committee has the authority to reject a Nexus Study update and continue operating under the 2009 Nexus Study. The effects of this decision can be widespread throughout the subregion, as many member jurisdictions will lose TUMF funding for facilities added to the TUMF Network during the update. Examples of such facilities include the Franklin Street / I-15 Interchange, Cajalco Road / I-15 Interchange, Scott Road / I-215 Interchange, Limonite Avenue, Whitewood Road, and the Adams Street / SR-91 Interchange, among others. Additionally, TUMF has not been increased in over seven years, while construction costs have increased by over thirty percent.

Effect of any fee increase: In spring 2016, WRCOG retained Economic & Planning Systems to conduct a comprehensive fee analysis for the jurisdictions in and around this subregion. A key finding from the study concluded that, with the exception of the retail land use, fees assessed on new development in the WRCOG subregion are in line with those assessed on new development in San Bernardino County. The fee analysis determined that with the proposed increase in TUMF, the change in total development costs for all the land uses would be less than one percent.

Benefits of the TUMF Program: Since Program inception in 2003, the TUMF Program has contributed funding to the completion of eighty-seven projects. The contribution of more than $400 million has been leveraged with various funding sources, which represents more than $1 billion in transportation improvements. Participation in the TUMF Program by member; jurisdictions allows those in compliance with the Program to receive funding from Measure A.

Change in TUMF Administrative Responsibilities: At its meeting on January 26, 2017, RCTC approved an item to further discuss the potential for the WRCOG TUMF Program to be transferred to RCTC's responsibility. WRCOG staff will be bringing this item to the February meeting of WRCOG's Administration & Finance Committee for further discussion. Staff will be forwarding any recommendation of the Administration & Finance Committee to the Executive Committee for any action in March. Staff does not recommend at this time delaying the Nexus Study while this item is discussed.

The tentative schedule of remaining tasks for the Nexus Study is as follows:

January 2017:	TUMF Nexus Study Ad Hoc Committee recommends a phase-in option for review by the Committee structure to finalize the Nexus Study;
February 2017:	WRCOG releases a draft Nexus Study for review and comment by stakeholders (the draft Nexus Study comment period will be 30 days);
February 8, 2017:	Administration & Finance Committee conducts first review of the draft Nexus Study and recommendation by the Ad Hoc Committee;
February 16, 2017:	Technical Advisory Committee conducts first review of the draft Nexus Study and recommendation by the Ad Hoc Committee;
March 2017:	WRCOG responds to any comment(s) received during the 30-day comment period of the draft Nexus Study;
March 6, 2017:	Executive Committee conducts first review of the draft Nexus Study and recommendation by the Ad Hoc Committee;
March 8, 2017:	Administration & Finance Committee conducts second review of the draft Nexus Study and recommendation by the Ad Hoc Committee;
March 16, 2017:	Technical Advisory Committee conducts second review of the draft Nexus Study;
April 3, 2017:	Executive Committee conducts second review of the draft Nexus Study;
April 12, 2017:	Administration & Finance Committee makes a recommendation on the draft Nexus Study;
April 20, 2017:	Technical Advisory Committee reviews recommendation on the draft Nexus Study;
May 1, 2017:	Executive Committee reviews recommendation on the draft Nexus Study and takes action;
July / August 2017:	Any change in fee goes into effect (depending on each member jurisdiction's approval of TUMF Ordinance / Resolutions).

Prior Actions:

January 19, 2017:	The Technical Advisory Committee received report.
January 12, 2017:	The Public Works Committee received report.
January 11, 2017:	The Administration & Finance Committee 1) approved staff's recommendation to approve the appeal; and 2) recommended that the Executive Committee approve the appeal consistent with staff's recommendation.
January 9, 2017:	The Executive Committee received report.
December 8, 2016:	The Public Works Committee approved the revised TUMF Network for inclusion in the TUMF Nexus Study.

Fiscal Impact:

TUMF activities are included in the Agency's adopted Fiscal Year 2016/2017 Budget under the Transportation Department.

<u>Attachment</u>:

None.